Carbon Storage Atlas

Fifth Edition

National Energy Technology Laboratory

U.S. Department of Energy | Office of Fossil Energy

Foreword: Carbon Storage Atlas (5th Edition)

It's hard to overstate the value and importance of the *U.S. Department of Energy's Carbon Storage Atlas* as an enterprise. This fifth edition is the culmination of a decade of work led by National Energy Technology Laboratory (NETL) scientists and engineers with their partners to provide a new scientific and technical foundation to the important work of carbon capture, utilization, and storage (CCUS)—deep reductions in greenhouse gas emissions through geological carbon storage.

Since large, permeable, porous rock volumes are required for the indefinite safe and secure storage of CO_2, there is no CCUS without geological storage. In this, viable storage targets and their associated rock volumes are like any other natural resource—and as such, must be mapped and quantified to provide decision makers with sufficient understanding. The *Carbon Storage Atlas* series began as an attempt to do several things:

- Provide information to many stakeholders about what CCUS is and how it works.
- Provide information to decision makers about the CO_2 storage resources in their states and regions.
- Establish methodologies for estimating CO_2 storage resources, as well as pathways to improve those assessments.

This required a profound integration of information from private and public stakeholders, much of which was done through the Regional Carbon Sequestration Partnerships. It required NETL to build a data infrastructure to support these goals, including the National Carbon Sequestration Database and Geographic Information System (NATCARB) data network, and platforms like the Energy Data eXchange (EDX) for data sharing. It required the interaction and engagement of many government agencies, including the U.S. Geological Survey (USGS) and U.S. Environmental Protection Agency (EPA), as well as industry, non-government organizations (NGOs), and academic participation.

When the first *Atlas* was published in 2007, there were only two comparable studies anywhere in the world (Alberta, Canada and Australia). The first volume of the *Carbon Storage Atlas* had a profound effect on the CCUS community as well as in industry and government. Many people, organizations, and governments quickly understood the value of this kind of information. The Energy Policy Act amendments in 2009 specifically called out the need for carbon storage assessment by both the DOE and USGS. Importantly, the *Carbon Storage Atlas* series prompted similar efforts worldwide. These included early attempts to assess the geological storage potential of India, China, and South Africa (as well as more refined events afterwards), as well as partnerships between the United States, Canada, and Mexico for the generation of a *North American Atlas*. It helped make the case to companies and countries that the characterization for CO_2 storage natural resources was a critical enterprise in a carbon-constrained world. It also led to efforts by academic and government researchers to actively improve their approaches to the assessments of CO_2 storage resources, including the local characterization for project development as a necessary follow-on to the high-level characterization of the *Atlas* work.

Throughout this work, NETL has been at the forefront of this issue leading the development of new science and technology through the generation and refinement of the *Atlas* series. This volume highlights some of the specific research and development (R&D) programs past and current that feed the *Atlas*, ranging from data aggregation and sharing to fundamental science on CO_2-rock interactions. That said, NETL's decade-long stewardship of this mission and technical leadership of the effort has also generated important work around the country on this topic, and has fed a national and international enterprise catalyzing important technical and political developments.

As a proponent and practitioner of CCUS as an important option for carbon management, I thank NETL and all their partners for the excellent work on this volume and earlier volumes. Future generations of scientists, investors, policy makers, and operators will look back on this series and understand its indispensable role in creating a low carbon future.

Dr. S. Julio Friedmann
Principal Deputy Assistant Secretary, Office of Fossil Energy
U.S. Department of Energy
August 20, 2015

Background image courtesy of Tim Ford.

Preface

The U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) is proud to release the fifth edition of the *Carbon Storage Atlas (Atlas V)*. Production of *Atlas V* is the result of collaboration among carbon storage experts from local, State, and Federal agencies, as well as industry and academia. The primary purpose of *Atlas V* is to provide a coordinated update of carbon dioxide (CO_2) storage resources for the United States and other portions of North America, and to provide updated information on carbon storage activities and the Regional Carbon Sequestration Partnerships (RCSPs) large-scale field projects.

A key aspect of CCS deals with the amount of carbon storage resources available to effectively help reduce greenhouse gas emissions. As demonstrated in *Atlas V*, CCS holds great promise as part of a portfolio of technologies that enables the United States and the rest of the world to effectively address climate change while meeting the energy demands of the global population. *Atlas V* includes current and best available estimates of potential CO_2 storage resource determined by a methodology applied across all regions.

Atlas V provides low, medium, and high estimates of the CO_2 prospective storage resource for regions in the United States and North America assessed by the RCSPs. Combined totals for all assessed regions are given in the following table.

Atlas V CO_2 Storage Resource Estimates			
	Low	**Medium**	**High**
Oil and Natural Gas Reservoirs	186	205	232
Unmineable Coal	54	80	113
Saline Formations	2,379	8,328	21,633
Total	**2,618**	**8,613**	**21,978**

**Data current as of November 2014. Estimates in billion metric tons.*

Estimates of the CO_2 prospective storage resource represent the fraction of pore volume of porous and permeable sedimentary rocks available for CO_2 storage and accessible to injected CO_2 via drilled and completed wellbores. These estimates do not include economic or regulatory constraints; only physical constraints are applied to define the accessible part of the subsurface. The storage estimates reported in NETL's *Carbon Storage Atlases* have benefitted over time from the additional information available from formation studies, as well as from improved methodologies that have reduced uncertainty and increased accuracy and precision in the estimates.

The number of stationary CO_2 sources and CO_2 emissions reported in *Atlas V* is based on information gathered by the National Carbon Sequestration Database and Geographic Information System (NATCARB) as of November 2014. Likewise, the CO_2 storage resource estimates reported in *Atlas V* are based on information gathered by NATCARB as of November 2014. NATCARB is updated as new data are acquired and methodologies for CO_2 storage estimates improve. Furthermore, it is expected that, through the ongoing work of NETL scientists and engineers and their partners, data quality and conceptual understanding of the CCS process will improve, resulting in more refined CO_2 storage resource estimates.

About *Atlas V*

The *Carbon Storage Atlas* contains the following sections: (1) Introduction to CCS; (2) DOE's Carbon Storage Activities; (3) National Perspectives; (4) Large-Scale Field Projects; (5) Small-Scale Field Projects; and (6) American Recovery and Reinvestment Act (ARRA) Site Characterization Projects. The Introduction to CCS section is an overview of CCS. The DOE's Carbon Storage Activities section is a summary of CCS activities including information on DOE's Carbon Capture and Storage Programs, NETL's Research and Development, DOE's Systems Analysis Activities, and DOE's Interagency and Global Collaborations, and Knowledge Sharing Efforts. The National Perspectives section contains maps showing the number, location, and magnitude of CO_2 stationary sources in the United States and other portions of North America, as well as the areal extent and estimated CO_2 prospective storage resource available in RCSP-evaluated geologic formations. The Large-Scale Field Projects section provides detailed information on various aspects of the large-scale injections conducted by the RCSPs. The Small-Scale Field Projects and Site Characterization Projects sections provide summaries of field project activities that augment the efforts of the large-scale field projects.

Atlas *V* highlights the RCSPs' large-scale field projects. These field projects are unique and address technical and non-technical challenges within their respective regions. The RCSPs are a success story in collaboration and integration of technologies in their trailblazing efforts to provide a firm foundation for moving forward with commercial-scale carbon storage projects. For each of the RCSPs' large-scale field projects, the *Atlas* provides a summary of approaches taken, technologies validated, and lessons learned in carrying out key aspects of a CCS project: site characterization; risk assessment, simulation and modeling, monitoring, verification, accounting and assessment; site operations; and public outreach.

Carbon dioxide geologic storage information in *Atlas V* was developed to provide a high-level overview of prospective storage resource across the United States and other portions of North America. Areal extents of geologic formations and CO_2 storage resource presented are intended to be used as an initial assessment. This information provides CCS project developers a starting point for further investigation of the extent to which geologic CO_2 storage is feasible, but is not intended as a substitute for site-specific characterization, assessment, and testing.

Acknowledgements

Assembling a volume as comprehensive as the *Carbon Storage Atlas* requires collaboration from many talented minds and experts across the carbon storage community. This document was compiled to present carbon storage resources across North America with assessments tailored to each region, which was no small task. In preparing *Atlas V*, NETL worked with our partners in the seven Regional Carbon Sequestration Partnerships, government agencies at all levels, and scientists and engineers in industry and academia.

This edition was made possible through the dedication and skill of project managers, researchers, and the highly proficient staff at NETL. I'd like to give special recognition to Traci Rodosta, Kanwal Mahajan, Andrea Dunn, Mary Sullivan, Angela Goodman, Grant Bromhal, Timothy Grant, Lynn Brickett, Terry Summers, and team members from Leonardo Technologies Inc. (LTI).

The *Atlas* is one of NETL's most trusted, referenced, and requested publications. As NETL's Director, I am proud of all the individuals who worked tirelessly to continue this tradition of excellence for the fifth edition.

Grace M. Bochenek, Ph.D.
Director, National Energy Technology Laboratory

Acronyms and Abbreviations

1-D	One-Dimensional
2-D	Two-Dimensional
3-D	Three-Dimensional
ADEM	Alabama Department of Environmental Management
ADM	Archer Daniels Midland Company
ALARP	as low as reasonably practicable
AoR	Area of Review
ARI	Advanced Resources International, LLC
ARRA	American Recovery and Reinvestment Act
bbl	barrel
BLM	Bureau of Land Management
BOEM	Bureau of Ocean Energy Management
BPM	Best Practice Manual
BSCSP	Big Sky Carbon Sequestration Partnership
CCPII	Carbon Capture Project
CCS	Carbon Capture and Storage
CERC	U.S.-China Clean Energy Research Center
CF	Certification Framework
CO_2	Carbon Dioxide
CSLF	Carbon Sequestration Leadership Forum
CT	computed tomography
CX	Categorical Exclusion
DAS	Detailed Area of Study
DCS	Distributed Control System
DOE	U.S. Department of Energy
DOI	U.S. Department of Interior
DOT	U.S. Department of Transportation
DTS	Digital Temperature System
EA	Environmental Assessment
EDX	Energy Data eXchange
EERC	Energy & Environmental Research Center
EGR	Enhanced Gas Recovery
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ERT	Electrical Resistance Tomography
FE	Office of Fossil Energy
FEP	Features, Events, and Processes
Ft^3	Cubic Feet
FWU	Farnsworth Unit
G-8	Group of Eight
GC	Gas Chromatograph
GCCSI	Global Carbon Capture and Storage Institute
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GWPC	Ground Water Protection Council
HiVIT	High Volume Injection Test
hp	Horsepower
HR3D	high-resolution 3-D
HTCM	heat transport, reactive transport and geomechanics
IBDP	Illinois Basin – Decatur Project
ICCS	Illinois Industrial Carbon Capture and Storage
IEA	International Energy Agency
IEAGHG	International Energy Agency Greenhouse Gas R&D Programme
IGCC	Integrated Gasification Combined Cycle
InSAR	Interferometric Synthetic Aperture Radar
IOGCC	Interstate Oil and Gas Compact Commission
ISGS	Illinois State Geological Survey
J/T_r	Jurassic/Triassic
KGS	Kentucky Geological Survey
kPag	Kilopascal Gauge
kW	Kilowatt
LBNL	Lawrence Berkeley National Laboratory
LIDAR	Light Detection and Ranging
LLNL	Lawrence Livermore National Laboratory
LSEM	Lithostratigraphic Earth Model
MBM	Modular Borehole Monitoring
mD	Millidarcy
MEM	Mechanical Earth Model
MGSC	Midwest Geological Sequestration Consortium
MHI	Mitsubishi Heavy Industries
MIT	Mechanical Integrity Test
MMscf/D	Million Standard Cubic Feet Per Day
MPag	Megapascal Gauge
MRCSP	Midwest Regional Carbon Sequestration Partnership
MRV	Monitoring, Reporting, and Verification
MSD	Mass Selective Detector
MVA	Monitoring, Verification, and Accounting
MW	Megawatt
MWe	Megawatt Electrical
N_2	Nitrogen
NACAP	North American Carbon Storage Atlas Partnership
NACSA	North American Carbon Storage Atlas
NATCARB	National Carbon Sequestration Database
NEPA	National Environment Policy Act
NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
NGO	Non-Government Organization
NPV	Net Present Value
NRAP	National Risk Assessment Partnership
NRCan	Natural Resources Canada
O&M	Operation and Maintenance
O_2	Oxygen
OCS	Outer Continental Shelf
OPPB	Office of Program Performance and Benefits
ORD	Office of Research and Development
P&A	Plugged and Abandoned
PC	Pulverized Coal
PCOR Partnership	Plains CO_2 Reduction Partnership
PFC	Perfluorocarbon
PISC	Post-Injection Site Care
PNC	Pulsed Neutron Capture
psi	Pounds Per Square Inch
psia	Pounds Per Square Inch Absolute
psig	Pounds Per Square Inch Gauge
R&D	Research and Development
RCSP	Regional Carbon Sequestration Partnership
RITE	Research Institute of Innovative Technology for the Earth
RMCCS	Rocky Mountain Carbon Capture and Storage Project
RTAC	Real Time Acquisition Computer
SECARB	Southeast Regional Carbon Sequestration Partnership
SEM	Static Earth Model
SERC	Science and Engineering Research Committee
SGR	South Georgia Rift
SHPO	State Historical Preservation Office
SSEM	Sequence Stratigraphic Earth Model
STEP	Sequestration Training and Education Program
SubTER	Subsurface Technology and Engineering Research, Development, and Demonstration
SWP	Southwest Regional Partnership on Carbon Sequestration
TDS	Total Dissolved Solids
UIC	Underground Injection Control
USACE	U.S. Army Corps of Engineers
USDW	Underground Source of Drinking Water
USGS	U.S. Geological Survey
VGM	Variable Grid Method
VSP	Vertical Seismic Profiling
WAG	Water-Alternating-Gas
WY-CUSP	Wyoming Carbon Underground Storage Project

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Background image: Sideling Hill, a narrow mountain ridge, located in West Virginia, Maryland, and Pennsylvania, USA. Sideling Hill photos are also included on the front cover, page 4, and page 7. Courtesy of Andrea Dunn (NETL).

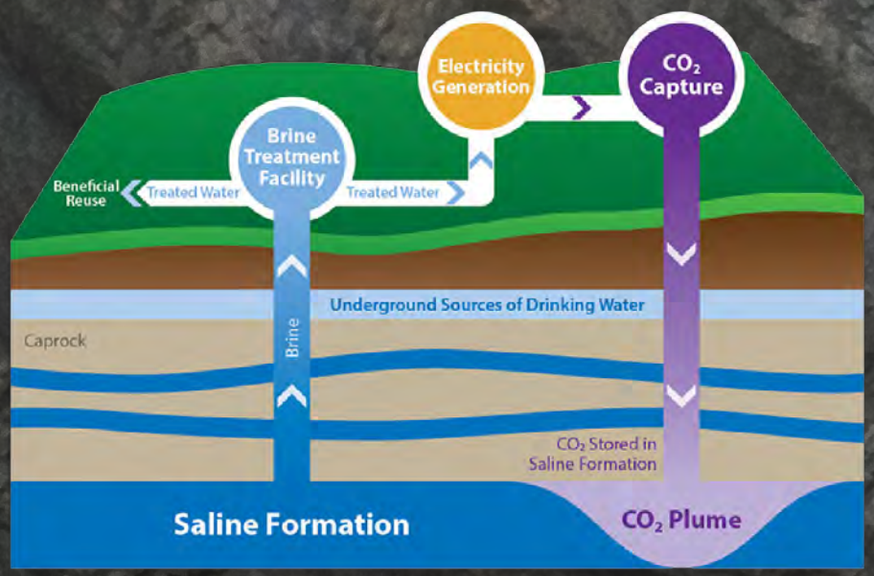
Introduction to CCS

What Is Carbon Capture and Storage?

Carbon capture and storage (CCS) is the separation and capture of carbon dioxide (CO_2) from the emissions of industrial processes prior to release into the atmosphere and storage of the CO_2 in deep underground geologic formations.

CCS enables industry to continue to operate while emitting fewer greenhouse gases (GHGs), making it a powerful tool for mitigating anthropogenic CO_2 in the atmosphere. However, geologic CO_2 storage in a subsurface formation must be safe, permanent, environmentally sustainable, and cost effective. Suitable storage formations can occur in both onshore and offshore settings, and each type of geologic formation presents different opportunities and challenges. The U.S. Department of Energy (DOE) is investigating five types of storage and underground formations for geologic CO_2 storage: saline formations, oil and natural gas reservoirs, unmineable coal, organic-rich shale basins, and basalt formations.

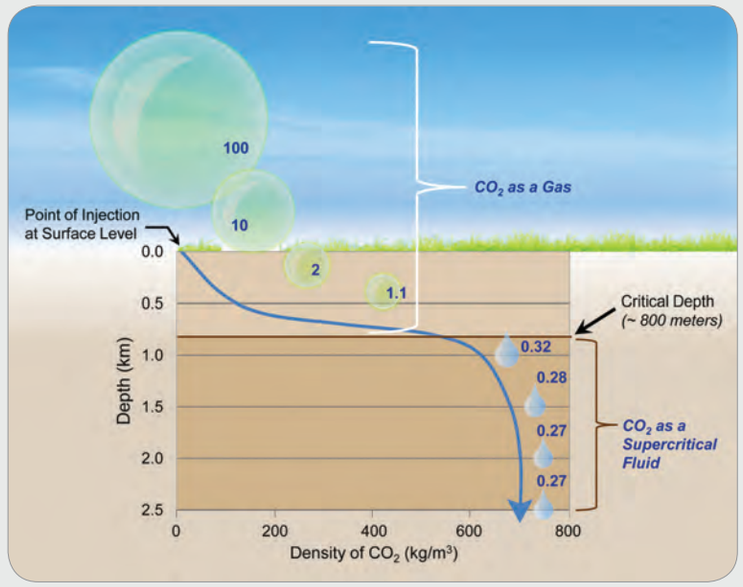
Carbon dioxide can be stored underground as a supercritical fluid. "Supercritical CO_2" means that the CO_2 is at a temperature exceeding 31.1 °C and a pressure exceeding of 72.9 atmospheres (approximately 1,057 pounds per square inch); this temperature and pressure defines the critical point for CO_2. At such high temperatures and pressures, the CO_2 has some properties like a gas and some properties like a liquid. The temperature naturally increases with depth in the Earth's crust, as does the pressure of the fluids (brine, oil, or gas) in the rocks. At depths below approximately 800 meters (approximately 2,600 feet), the natural temperature and fluid pressures exceed the critical point of CO_2 for most places on Earth. This means that CO_2 injected at this depth or deeper will remain in the supercritical condition given the temperatures and pressures present. For more information, visit the Carbon Storage Program's **Frequently Asked Questions** webpage.



Carbon storage diagram showing CO_2 injection into a saline formation while producing brine for beneficial use.

Supercritical (Dense Phase) CO_2

Experts commonly discuss storing CO_2 in the supercritical (dense phase) condition. In supercritical condition, CO_2 is at a temperature exceeding 31.1 °C and a pressure exceeding 72.9 atm (approximately 1,057 psi); this temperature and pressure defines the critical point for CO_2 and occurs at depths below the Earth's surface of about 800 meters (approximately 2,600 feet). At such temperatures and pressures, the CO_2 has some properties like a gas and some properties like a liquid. In particular, it is dense like a liquid, but has viscosity like a gas. The main advantage of storing CO_2 in the supercritical condition is that the required storage volume is less than if the CO_2 were at standard (room) pressure conditions. This reduction in volume is illustrated below. The blue numbers show the CO_2 volume at each depth compared to a reference volume of 100 at the surface.



Pressure effects on CO_2 volume (based upon image from the Cooperative Research Centre for Greenhouse Gas Technologies [CO2CRC]).

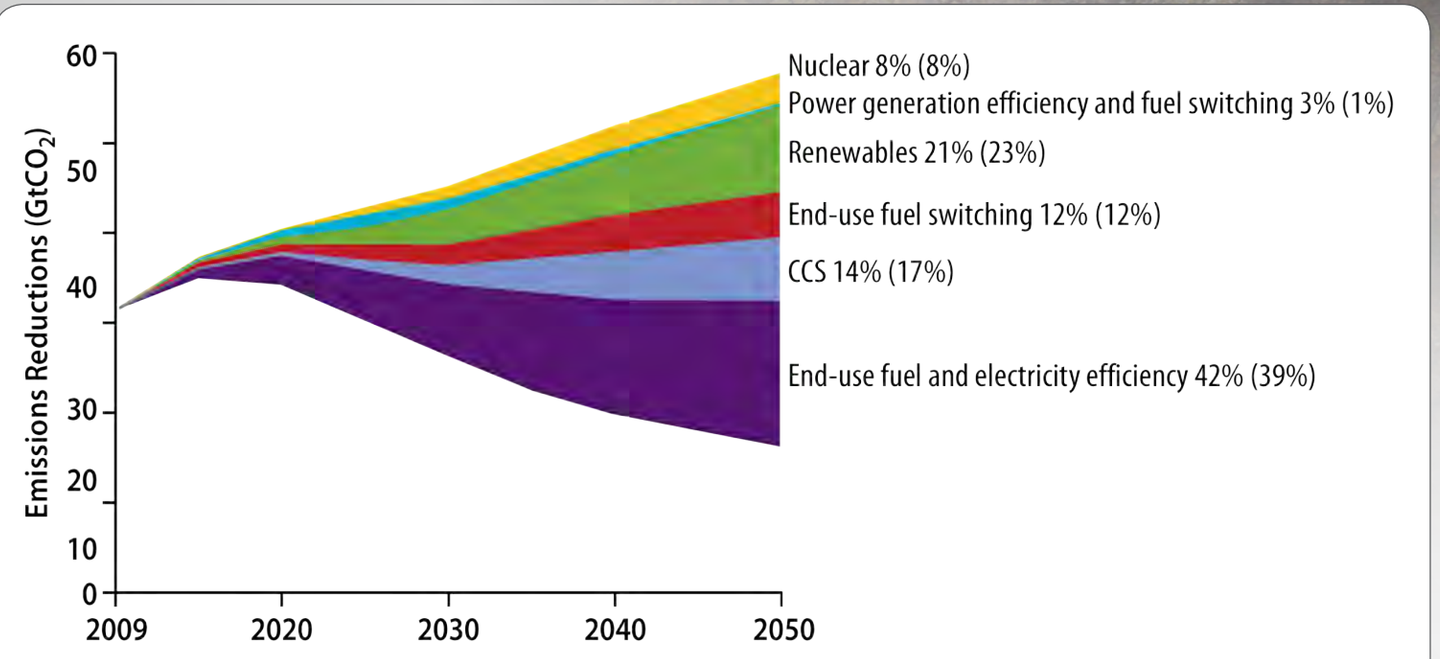
Background image courtesy of Tim Ford.

Why Is CCS Needed?

Globally, fossil fuels—coal, oil, and natural gas—currently provide and are expected to continue to provide the vast majority of energy needed (particularly electricity) to sustain and improve quality of life. Fossil fuels contain high percentages of the chemical element carbon. When fossil fuels are burned, carbon reacts with oxygen to produce CO_2. Due to the reliance on fossil fuels for both energy production and industrial processes, the amount of CO_2 in the atmosphere has increased since the Industrial Revolution. As the amount of CO_2 in the atmosphere increases, more heat is radiated back from the Earth's surface and trapped in the Earth's atmosphere. The increase in GHG concentrations in the atmosphere, in turn, leads to increasing global temperatures.

It is expected that coal and natural gas will continue to play a critical role in generating electricity both domestically and globally for the next several decades. For more than 20 years, scientists have been investigating CCS from stationary sources, such as coal- and natural gas-fired power plants, as one option for mitigating CO_2 emissions. During the past decade, CCS has gained considerable recognition among the broader global scientific community, as well as policymakers, as a promising option to reduce GHG emissions. The International Energy Agency (IEA), the IEA Greenhouse Gas R&D Program (IEAGHG), and the U.S. Environmental Protection Agency (EPA), among other organizations, have strongly endorsed CCS technology. For example, in 2013, the Executive Director of the IEA stated: "After many years of research, development, and valuable but rather limited practical experience, we now need to shift to a higher gear in developing CCS into a true energy option, to be deployed in large scale" (IEA Technology Carbon Capture and Storage Roadmap, 2013). Similarly, in 2014 the United Nations' Intergovernmental Panel on Climate Change (a Nobel Prize winning organization) concluded in its Fifth Assessment Report on climate change that CCS was a technology with the potential for important contributions to the mitigation of GHG emissions by 2030 (IPCC 2014). The report listed CCS as a key technology for mitigation in both the energy and industrial sectors.

CCS is an important component of the broad portfolio of approaches and technologies that will be needed if climate change is to be successfully addressed. CCS could allow fossil fuels to remain part of the global energy mix by limiting the emissions from their use. To achieve significant emissions reductions, the United Nations Economic Commission for Europe (UNECE) provided formal recommendations to the United Nations Framework Convention on Climate Change (UNFCCC) stating that CCS must be recognized and supported in the new global climate change agreement, must receive policy parity with other low-carbon technologies, and should receive government support for global demonstration projects. For more information about why CCS is needed, visit the Carbon Storage Program's **Frequently Asked Questions** webpage.



Note: Per IEA, the numbers in parentheses are shares in 2050. For example, 14% is the share of CCS in cumulative emission reductions through 2050, and 17% is the share of CCS in emission reductions in 2050, compared with the 6 °C Scenario.

(Source: 2013 IEA Global CCS Roadmap).

Different technologies contribute to meeting the energy sector target of cutting CO_2 emissions by more than half by 2050.

DOE's Carbon Capture and Storage Activities

Background image: Isolated pore space from a sub-core of Mt. Simon sandstone, obtained from the subsurface and scanned with NETL computed tomography equipment. Diameter of the sub-core is roughly the diameter of a pencil.

DOE's Carbon Capture and Storage Efforts

Addressing the potential adverse impacts from climate change is a top priority for the U.S. Department of Energy (DOE). As the global temperature increases, wildfires, drought, severe weather, and electricity demand place stress on the Nation's energy infrastructure.

DOE supports research and advancement that makes fossil energy technologies cleaner and less impactful to people and the environment. DOE is taking steps to cut CO_2 emissions through clean energy innovation.

DOE's clean coal research and development (R&D) is focused on developing and demonstrating advanced power generation and carbon capture, utilization, and storage technologies for existing facilities and new fossil-fueled power plants by increasing overall system efficiencies and reducing capital costs. In the near-term, advanced technologies that increase the power generation efficiency for new plants and technologies to capture CO_2 from new and existing industrial and power-producing plants are being developed. In the longer term, the goal is to increase energy plant efficiencies and reduce both the energy and capital costs of CO_2 capture and storage from new, advanced coal plants and existing plants. These activities will help allow coal to remain a strategic fuel for the Nation while enhancing environmental protection.

DOE's CCS research advances safe, cost-effective, capture and permanent geologic storage and/or use of CO_2. The technologies developed and large-volume injection tests conducted through this program will benefit the existing and future fleet of fossil fuel power generating facilities by creating tools to increase our understanding of geologic reservoirs appropriate for CO_2 storage and the behavior of CO_2 in the subsurface.

DOE's Office of Fossil Energy (FE) is developing a portfolio of technologies that can capture and permanently store GHGs. The Carbon Capture Program, administered by the FE and the National Energy Technology Laboratory (NETL), is conducting R&D activities on Second Generation and Transformational carbon capture technologies that have the potential to provide step-change reductions in both cost and energy penalty as compared to currently available First Generation technologies. The Carbon Storage Program, also administered by FE and NETL, is focused on ensuring the safe and permanent storage and/or utilization of CO_2 captured from stationary sources. Carbon dioxide storage in geologic formations includes oil and natural gas reservoirs, unmineable coal, saline reservoirs, basalt formations, and organic-rich shale basins.

CARBON CAPTURE AND STORAGE (CCS)

is the separation and capture of CO_2 from the atmospheric emissions of industrial processes and the transport and safe, permanent storage of the CO_2 in deep underground geologic formations.

Background image: To better understand geologic formations, researchers at NETL's High-Pressure Immersion and Reactive Transport Laboratory in Albany are studying subsurface systems.

DOE'S CARBON CAPTURE PROGRAM

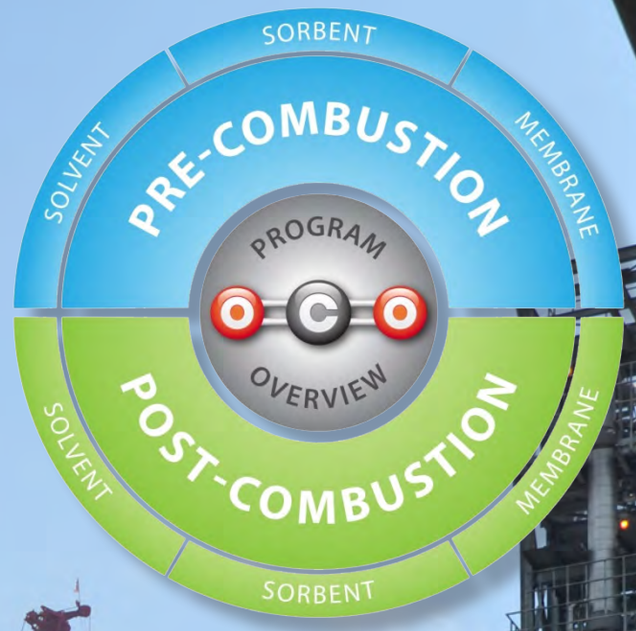
Carbon capture involves the separation of CO_2 from flue gas or synthesis gas (syngas) at fossil fuel power plants or from CO_2 emissions at other large industrial facilities. The Carbon Capture Program is developing a portfolio of technology options to enable the United States to continue to benefit from using the Nation's secure and affordable fossil fuel resources. Over the next few decades, technology innovations developed under this program will need to be broadly applied to both the Nation's coal-fired power plants, as well as its natural gas combined cycle (NGCC) fleet to meet the long-term goals for reducing CO_2 emissions. The challenge is to help position the economy to remain competitive, while reducing CO_2 emissions.

The **Carbon Capture Program** consists of two core research technology areas: (1) Post-Combustion Capture and (2) Pre-Combustion Capture. These core areas are focused on creating technological improvements providing a step-change in both cost and performance as compared to current state-of-the-art solvent-based capture systems.

Post-combustion capture is primarily applicable to conventional pulverized coal (PC)-fired power plants, where the fuel is burned with air in a boiler to produce steam that drives a turbine/generator to produce electricity. The carbon is captured from the flue gas after fuel combustion. Pre-combustion capture is applicable to integrated gasification combined cycle (IGCC) power plants, where solid fuel is converted into gaseous components (syngas) by applying heat under pressure in the presence of steam and oxygen. In this case, the carbon is captured from the syngas before combustion and power production occurs. In both cases, R&D is underway to develop solvent-, sorbent-, and membrane-based capture technologies. Although R&D efforts are focused on capturing CO_2 from the flue gas or syngas of coal-based power plants, the same capture technologies are applicable to natural gas- and oil-fired power plants and other industrial CO_2 sources.

The core research projects leverage public and private partnerships to support the goal of broad, cost-effective CCS deployment. Current efforts in the Major Demonstration Program are pursuing the demonstration of First Generation carbon capture technologies with existing and new power plants and industrial facilities using a range of capture alternatives. The Carbon Capture Program is performing R&D of Second Generation and Transformational advanced CO_2 capture technologies.

Although the majority of the Second Generation technology options being considered are still in the laboratory- and bench-scale stages of development, a limited number of small pilot-scale field tests have been initiated. Successful R&D efforts today have generated a demand to move the most promising Second Generation capture technologies on to large-scale pilot testing (10–50 MWe). This step will generate the knowledge required to efficiently integrate and demonstrate technologies at full scale in final preparation for commercialization.



Background image: Linde Group 1 MWe Post-combustion CO_2 Capture Pilot Plant at the National Carbon Capture Center in Wilsonville, Alabama.

DOE'S CARBON STORAGE PROGRAM

The overall objective of the **Carbon Storage Program** is to develop and advance CCS technologies both onshore and offshore that will significantly improve the effectiveness of the technology, reduce the cost of implementation, and be ready for widespread commercial deployment in the 2025–2035 timeframe.

To accomplish widespread deployment, technical and economic barriers must be overcome and data and information must be generated and communicated to inform regulators and industry on the safety and permanence of CCS.

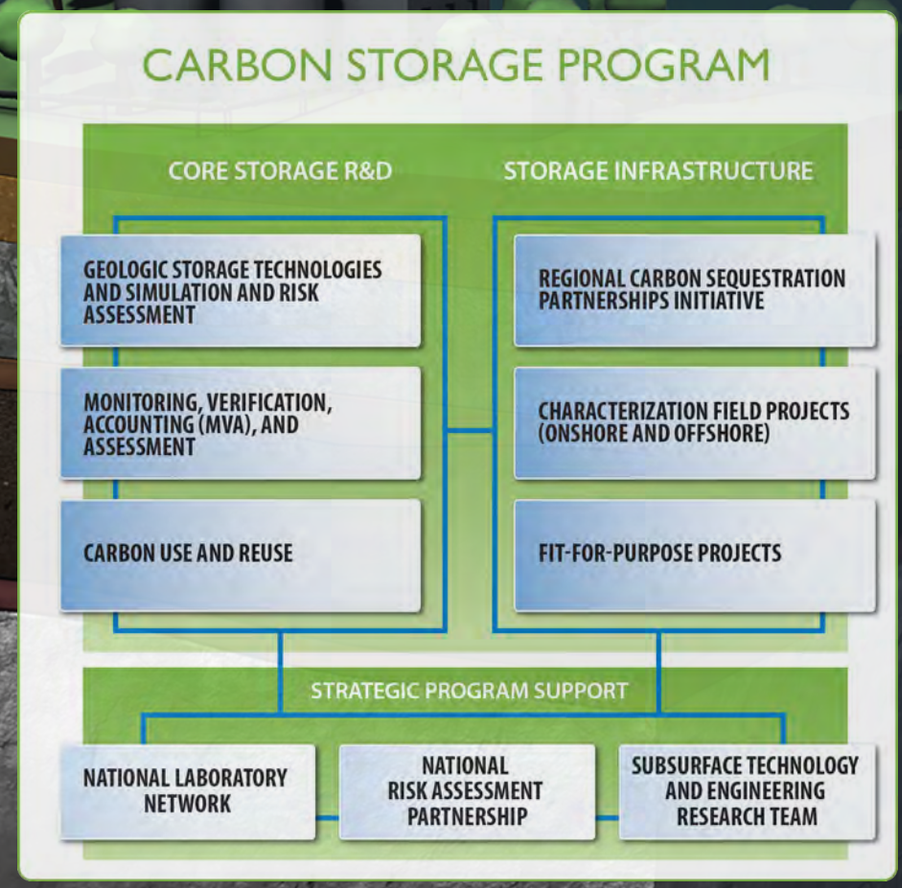
The Carbon Storage Program contains three principal components: **Core Storage R&D**; **Storage Infrastructure**; and **Strategic Program Support**. The integration of these components will address technological and marketplace challenges. Three technology areas are combined to form the Core Storage R&D technology component, which is driven by stakeholders' needs. The Storage Infrastructure technology component includes three technology pathways where validation of various CCS technology options and their efficacy are being confirmed, and represents the development of the infrastructure necessary for the deployment of CCS. The Storage Infrastructure technology component tests new technologies and benefits from specific solutions developed in the Core Storage R&D component. In turn, data gaps and lessons learned from small- and large-scale field projects are fed back to the Core Storage R&D technology component to guide future R&D.

A key element of the Carbon Storage Program is the **Regional Carbon Sequestration Partnership (RCSP) Initiative**. This initiative is carrying out regional characterization and field projects to demonstrate that different types of geologic storage reservoirs, distributed over different geographic regions of the United States, have the capability to permanently and safely store CO_2, providing the basis for commercial-scale CO_2 storage.

In addition to the RCSP Initiative, DOE is also conducting **site characterization field projects and fit-for-purpose** projects. Site characterization field projects focus on value-added reservoirs that can support the deployment of CCS technologies in both onshore and offshore settings. Fit-for-purpose projects are focused on developing specific subsurface engineering approaches to address research needs critical for advancing CCS to commercial scale, such as confirmation of modeling results for advanced pressure management with brine extraction.

Both **Core Storage R&D** and **Storage Infrastructure** sponsor applied research at laboratory scale, validate promising technologies at pilot scale, and support large-scale, large-volume injection field projects at pre-commercial scale to confirm system performance and economics. The Strategic Program Support activities contribute to an integrated domestic and international approach to ensure that CCS technologies are cost-effective and commercially available. The activities bring strategically focused expertise and resources to bear on issues that are key to commercial deployment of storage technologies.

Since 1997, DOE's Carbon Storage Program has significantly advanced the CCS knowledge base through a diverse portfolio of applied research projects. The portfolio includes industry cost-shared technology development projects, university research grants, collaborative work with other national laboratories, and research conducted in-house through NETL. More information is available in the **Carbon Storage Technology Program Plan**.



Managed within FE and implemented by NETL, the Carbon Storage Program works to develop effective and economically viable technology options for CCS. To accomplish this, the Carbon Storage Program focuses on developing technologies to store CO_2 to reduce GHG emissions from energy producers and other industries without adversely affecting the supply of energy or hindering economic growth.

CO_2 Prospective Storage Methodologies Research and Development

NETL is developing and evaluating a suite of methodologies to quantitatively assess storage resource for onshore and offshore storage reservoirs, including saline formations, oil and natural gas reservoirs, unmineable coal, and organic-rich shales. These methodologies directly address the high-level Carbon Storage Program goal of predicting storage capacity to +/-30 percent accuracy by further developing estimation methodologies.

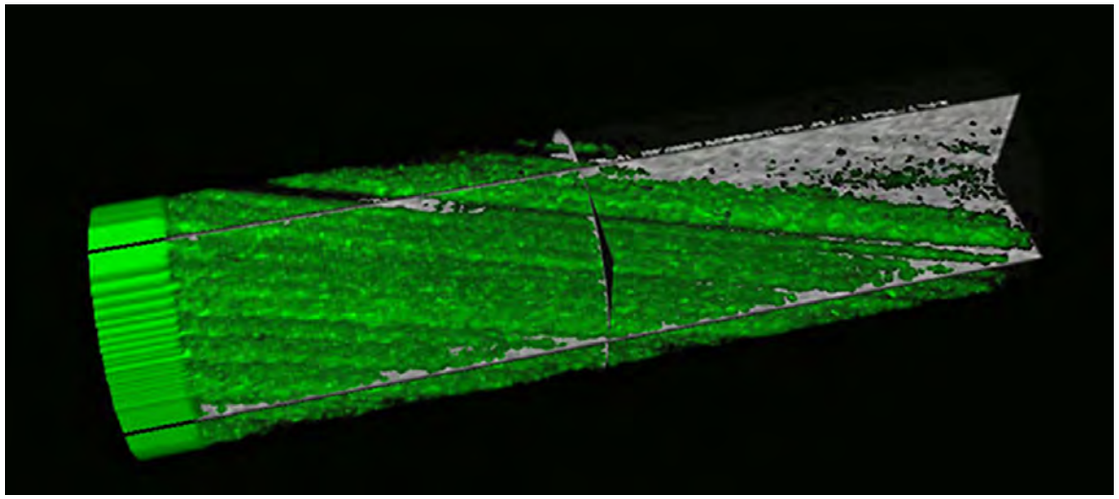
NETL researches engineered-natural systems to enable safe, sustainable production and utilization of domestic energy resources. NETL has world-class capabilities in geomaterials science, fluid flow in geologic media, multi-scale assessments, geospatial data management and analyses, and strategic monitoring of natural systems. NETL is focused on creating the knowledge base needed to enable the safe and sustainable use of fossil energy resources, and does so in the following technical domains: Energy Conversion Engineering, Materials Science and Engineering, Computational Science and Engineering, and Geological and Environmental Science. NETL offers a venue for participation in collaborative research and develops new technologies, processes, and models targeted to meet long-term goals set for programs managed under the Office of Coal and Power R&D. The Geological and Environmental Sciences Focus Area is the primary NETL focus area supporting the Carbon Storage Program.

Background image: South Dakota Department of Environment and Natural Resources, Geological Survey Program coring the Pierre Shale. Photo by Dan Soeder, 2014.

NETL is currently developing methodologies for CO_2 storage in conventional oil-bearing formations and CO_2 storage in unconventional organic-rich shale formations for inclusion in future versions of the Carbon Storage Atlas. NETL is also working toward developing a regional scale methodology for assessing offshore CO_2 storage.

Oil and Natural Gas Reservoirs

Researchers will use information on the distribution of ultimate storage efficiency in typical CO_2-enhanced oil recovery (CO_2-EOR) scenarios as the basis for prescribing a volumetric storage estimation method. This method is intended to have general applicability to oil-bearing formations across the United States. An analytical model, a reduced order model from numerical simulation, and field history and related forward projection of field practices are merged together to characterize the volumetric CO_2 storage efficiency in oil reservoirs.



Computed tomography image of CO_2 displacing brine in Berea Sandstone showing effects of heterogeneity in reducing sweep efficiency at the core scale.

Unconventional Organic-Rich Shale

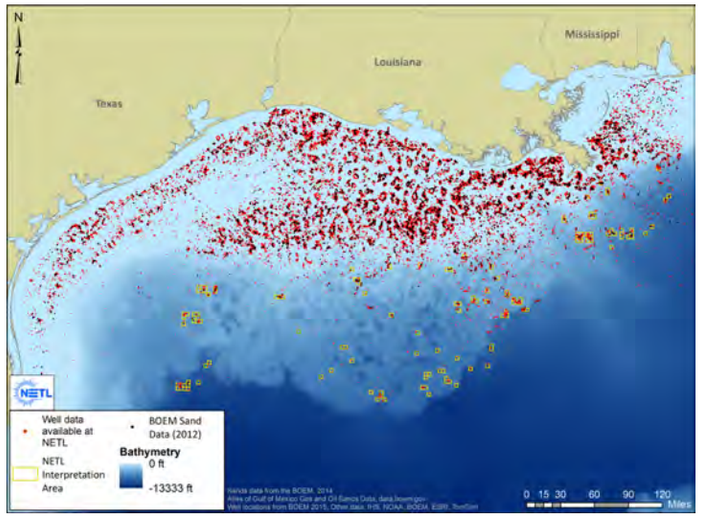
NETL is currently developing a methodology to volumetrically assess the CO_2 storage potential in organic-rich shale reservoirs. The ability of organic-rich shale formations to store CO_2 is based on these rocks containing and producing large quantities of natural gas. In a depleted gas shale, the volume formerly containing natural gas may be available for CO_2 storage. The volumetric method accounts for storage of CO_2 as a free-gas within fractures and matrix pores as well as a sorbed phase on organic matter and clays within hydraulically stimulated shale volumes. Future work will be focused on improving the understanding of pore-to-reservoir scale behavior of organic-rich shale to reduce the uncertainty associated with prospective storage estimates.

Parallel, vertical, orthogonal natural fracture faces (joint sets) in an outcrop of organic-rich Millboro Shale (Marcellus equivalent), Clover Creek, VA. Photo by Dan Soeder, 2014.

Offshore CO_2 Storage

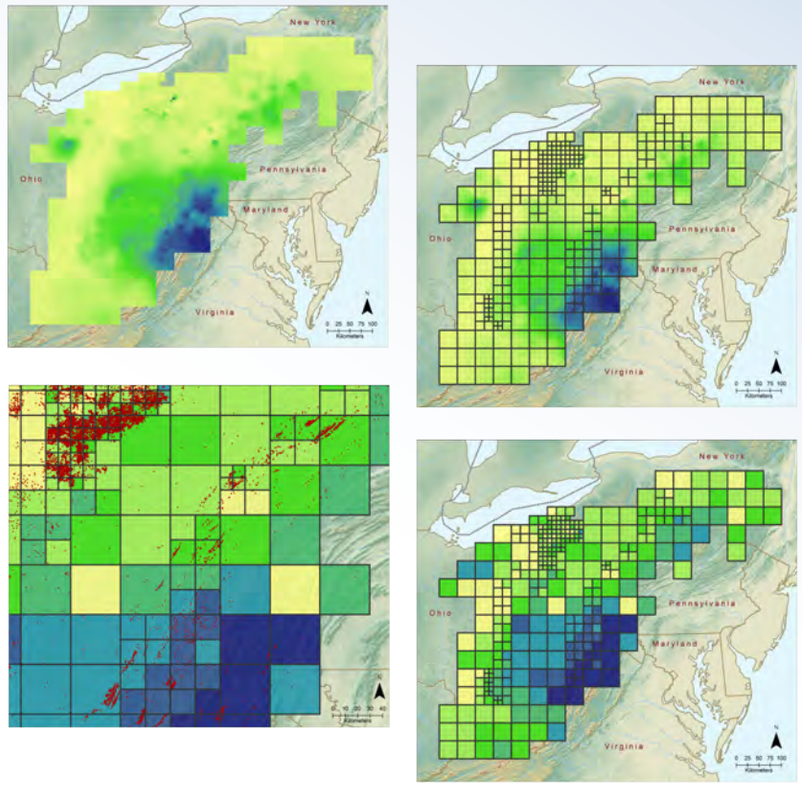
In future efforts, the offshore CO_2 methodology will leverage data and information about the offshore from the U.S. Gulf of Mexico and Arctic regions already developed and assimilated by NETL researchers as part of the Offshore Resources Portfolio in the Geological and Environmental Science Focus Area.

This map shows locations in the U.S. Gulf of Mexico where data is available to NETL, as well as areas where NETL has interpreted the subsurface geology. Data including reservoir parameters, well information, and subsurface analyses will be used to identify areas with the potential for CO_2 storage.



Variable Grid Method

NETL's Variable Grid Method (VGM) can be applied to the current storage methodology to refine the spatial resolution of model input(s) and effectively communicate and quantify CO_2 storage potential and the uncertainty underlying the assessed capacities. The VGM utilizes varying grid cell sizes to visually communicate and constrain uncertainty associated with input data to create an integrated visualization layer. To communicate the results in a manner accessible to a range of users, the VGM represents areas with a smaller range of uncertainty with smaller grid cells, while areas with larger uncertainty are signified with larger grid cells. The VGM can be applied to various data types (i.e., vector and raster) and formats (i.e., discrete, categorical, and continuous), as well as uncertainty categories or quantifications associated with a given dataset or analysis (e.g., data clusters, indices, sample density, sample variance, interpolations, empirical simulations, or probabilistic models). This flexibility allows the VGM to be customized to best address users' needs and applications. NETL's VGM seeks to address the information gap currently associated with spatial analytical products by simultaneously offering the consumer both the spatial interpretation along with a measure of the uncertainty.



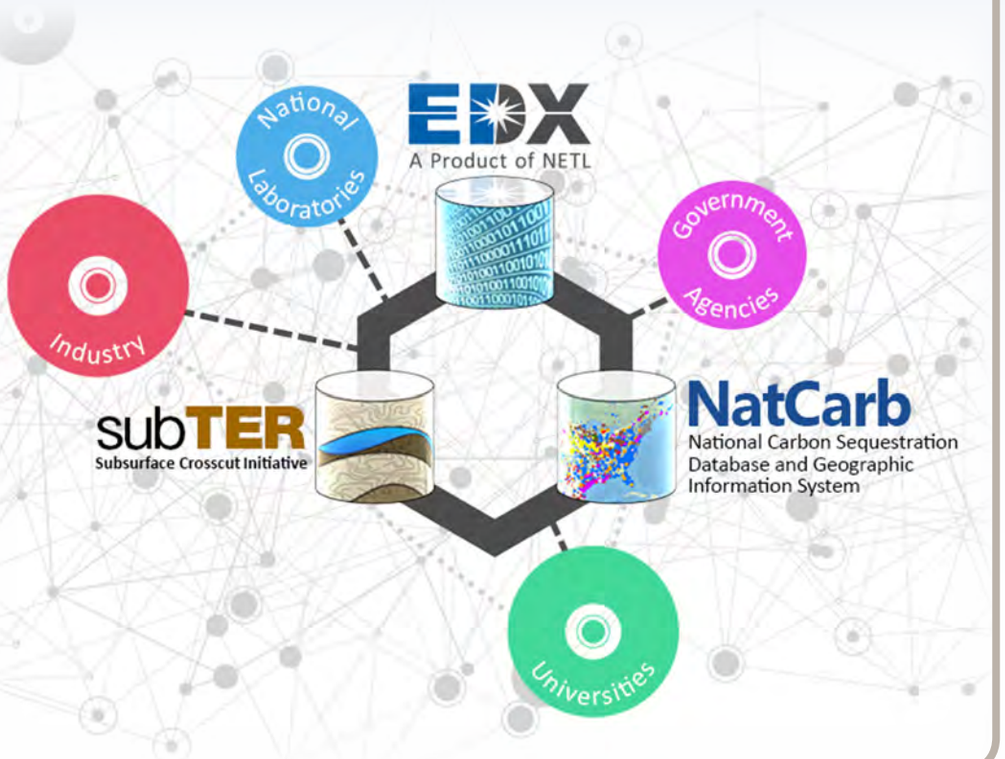
Example of a traditional representation of subsurface data (upper left) as a continuous surface compared to the same data presented with the VGM as an overlay (upper right) and as an integrated layer (bottom right, bottom left zoomed in for more detail). The VGM represents uncertainty utilizing grid cell size and data values with colors, while still preserving the overall data trends and patterns.

Cross-Disciplinary Approaches

Through partnerships with universities, the private sector, and other government agencies, the National Labs serve as regional hubs for scientific innovation and technological advancement. At NETL, collaboration is a key component to the complex challenges of fossil energy research. These challenges require cross-disciplinary approaches and quicker, more efficient access to resources. NETL's Energy Data eXchange (EDX) facilitates the active advancement of energy innovations by simplifying the logistics of research and collaboration. When the scientists from DOE's National Labs and other federal agencies need to work together to support carbon storage and other DOE R&D needs, EDX offers researchers and their collaborators an online tool to facilitate sharing, discovery, and development of data, tools, and resources key to efficient coordination and collaboration. EDX is a comprehensive, evolving tool for research and collaboration.

Today, EDX is improving coordination among NETL research teams and their outside collaborators in academia and industry. EDX's combination of efficient access to relevant public and private resources and capabilities for multi-agency projects, such as those affiliated with the National Carbon Sequestration Database (NATCARB), is especially valuable since NETL's research crosscuts multiple areas associated with fossil energy R&D. EDX Collaborative Workspaces have been leveraged by carbon storage multi-organizational project teams, allowing the researchers to focus more time and resources on the research itself and less on the mechanics of how to share or transfer information among team members. EDX houses a growing suite of pertinent work products associated with DOE R&D. From the beginning, EDX became the home of NATCARB, an assembly of data, including results from DOE R&D, that supports addressing technical and policy challenges of CCS. The NATCARB database is assembled with collaborative partnerships through the RCSPs and site characterization projects funded through the American Recovery and Reinvestment Act (ARRA). Other publicly available data repositories, such as U.S. Geological Survey Earth Resources Observation and Science Center (USGS-EROS) and EPA data warehouse, are also used to enhance its capabilities. The NATCARB database and NATCARB viewer are both accessible via EDX on its public side via "Search," "Groups," and "EDXtools" sections of EDX. As these resources evolve and mature with new products and information, they are updated through web feeds or periodic updates on the EDX system—thus, ensuring NATCARB resources remain current and relevant for all stakeholders.

As a system, the National Labs bring capabilities and expertise together to solve today's energy problems. Under the auspices of DOE's Subsurface Technology and Engineering Research, Development, and Demostration (SubTER) Tech Team, EDX is also supporting carbon storage R&D needs. For SubTER and the Carbon Storage Program, EDX offers research teams a multi-faceted online research tool, with capabilities for coordination and collaboration aimed at facilitating and accelerating energy technology innovation. Through SubTER efforts associated with EDX, the system will continue to evolve, incorporating advanced data mining, fusion, discovery, and utilization capabilities, including those associated with Big Data resources. EDX bridges the gap between U.S. DOE researchers and external collaborators to efficiently, effectively address carbon storage R&D and technology challenges.



Analysis to Support SWP

NETL's analytical support team is providing tracer analysis for the Southwest Regional Partnership on Carbon Sequestration (SWP) Farnsworth Project for the collection of perfluorocarbon (PFC) tracers co-injected with CO_2. NETL's PFC tracer laboratory utilizes thermal desorption in conjunction with a gas chromatograph (GC)/mass selective detector (MSD) to analyze exposed sorbent tubes for the presence of PFC tracers. NETL's tracer laboratory has extensive experience in handling the typical contamination found at a production location.

Injection of PFT at West Pearl Queen, New Mexico.

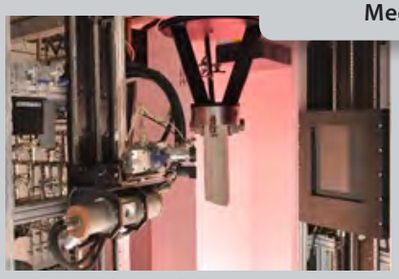
Injection of PFT at West Pearl Queen, New Mexico.

Agilent 6890N GC with Gerstel cryogenic focusing, coupled to a Agilent 5975 MSD for tracer analysis.

NETL Geoimaging Laboratory

Traditional petrographic and core-evaluation techniques typically aim to determine the mineral make-up and internal structure of rock cores, as well as to analyze properties influencing fluid flow. Often this type of evaluation is destructive; physically sectioning the core to capture the internal composition details. NETL's Geoimaging Laboratory provides a non-destructive alternative to these traditional methods. The Lab hosts three computed tomography (CT) X-ray scanners, an assortment of supporting flow-through instrumentation, and a mobile core logging unit. These technologies work in tandem to provide characteristic geologic and geophysical information at a variety of scales. The medical CT scanner and core logger analyze bulk structure, composition, and density variations. The industrial CT scanner images pore and fracture networks. Lastly, the micro-CT scanner allows evaluation of microscopic structure and pore surfaces. Porosity, permeability, fracture roughness and aperture, overall structure, and composition can all be analyzed, yielding quantifiable and relevant parameters to understand CO_2 flow under a wide variety of relevant storage conditions.

Medical CT scanner.



Industrial CT scanner.

Micro-CT scanner.

Monitoring Groundwater Impacts

NETL is currently developing and demonstrating a suite of protocols and tools for new types of geochemically based monitoring strategies for groundwater systems and developing a statistical understanding of natural groundwater variability in CO_2 storage systems. Monitoring of underground sources of drinking water (USDW) is crucial to the successful implementation of geologic carbon storage. Protection of groundwater resources is the main focus of regulations that dictate the requirements for permitting of CO_2 storage sites. A suite of groundwater monitoring techniques are being developed and/or tested at NETL with an emphasis on geochemical signals and isotopes, which are used to identify sources of contamination. NETL research on novel materials and sensing techniques are being developed for in-situ measurements of various geochemical signals including CO_2, pH, and chemistry. The techniques will be field tested and critically evaluated to develop a statistically based protocol for USDW monitoring. Field testing is being expanded through collaboration with the RCSPs and field demonstration projects.

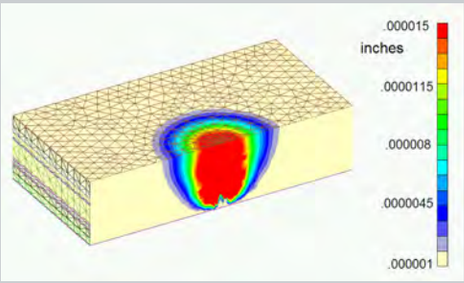
NETL's Thermo Scientific NEPTUNE PLUS MC-ICP-MS [multicollector-inductively coupled plasma-mass spectrometry] at the University of Pittsburgh, Department of Geology & Planetary Science.

NETL researchers in conjunction with collaborators at West Virginia University pioneered the use of a CarboQC carbonation meter used in the beverage industry (manufactured by Anton Paar) for the direct measurement of CO_2 in waters in the field setting.

NETL's Reservoir Simulation Software

Results of computer simulations allow insight into the physical and chemical interplay between the injected CO_2 and the material composing the storage stratum. Simulation outcomes suggest answers to the following: Where are the best locations for the injection wells? How far and in what direction will the CO_2 travel? Where should the monitoring instruments be placed? What signals should be targeted? These answers reveal how best to utilize a stratum for CO_2 storage, the amount of CO_2 that can be stored, and the risk of CO_2 release.

NETL is developing and improving its reservoir simulation software: FracGen, NFFlow, and ancillary programs. The software is designed to report fluid flow, pressure, and composition in strata exhibiting a network of fractures throughout a matrix of sedimentary rock. FracGen uses available geologic data to generate a stochastic representation of the fracture network. NFFlow uses that network and solves for fluid flow in the reservoir.



The type of result available from a computer simulation. The software shows the deformation of the earth near Hobbes, New Mexico, caused by injecting 2,000 tons of CO_2 into a deep stratum.

CO_2 Saline Storage and CO_2-EOR Cost Models

NETL's Office of Program Performance and Benefits (OPPB) conducts analyses to demonstrate how R&D activities support national and international priorities related to energy supply, energy use, and environmental protection. This team also examines the following three areas of analysis (with respect to the Carbon Storage Program): ***(1) Systems***—contextualizes research objectives (e.g., improvements in the cost and efficiency of CCS technologies); ***(2) Policy***—places CCS in the context of regulatory compliance and environmental policy; and; (***3) Benefits***—combines technology and policy to show economic and environmental costs and benefits that a successful carbon storage R&D program will provide both domestically and internationally. Supporting this effort, NETL has developed the CO_2 Saline Storage Cost Model and is developing the CO_2-EOR Cost Model.

The CO_2 Saline Storage Cost Model is a spreadsheet that estimates the revenues and capital, operating, and financial costs for a CO_2 storage project in a saline reservoir. These costs occur in one or more of the five stages of a storage project: regional geologic evaluation, site characterization, permitting, operations, and post-injection site care and site closure. The costs associated with long-term stewardship are not explicitly modeled. The model uses simplified reservoir engineering equations to model the storage process and includes a database of potential storage formations. The CO_2 Saline Storage Cost Model can estimate the revenue and costs for a single saline storage project or can cycle through a database of storage formations to generate the breakeven price/cost and CO_2 storage capacity for each storage formation (the breakeven price or cost occurs when the net present value for the project is zero). This data can be used to create a cost supply curve.

The CO_2-EOR Cost Model will estimate the revenues and capital, operating, and financial costs for a CO_2-EOR operation. Many of the costs in this model will come from the CO_2 Saline Storage Cost Model with modifications for modeling EOR operations. The CO_2-EOR Cost Model will use NETL's CO_2 Prophet Model to simulate the inputs (water and CO_2) and outputs (oil, water, and CO_2) for a single pattern in an EOR field. The model will incorporate a database of oil reservoirs developed by the Energy Information Administration (EIA). The model will include the costs for complying with Subpart UU of the EPA's GHG Reporting Regulations. It will also include the costs for complying with the Underground Injection Control (UIC) Class VI injection well regulations and Subpart RR regulations for Class VI wells, should the user choose to include these costs. The CO_2-EOR Cost Model will be able to estimate the breakeven oil price and oil output for a single oil reservoir or cycle through the database of oil reservoirs to generate the data needed to create a cost supply curve.

Stages of Operations for Geologic Storage and Enhanced Oil Recovery Modeled in the CO_2 Saline Storage and CO_2-EOR Cost Models

Geologic Storage (GS) Class VI

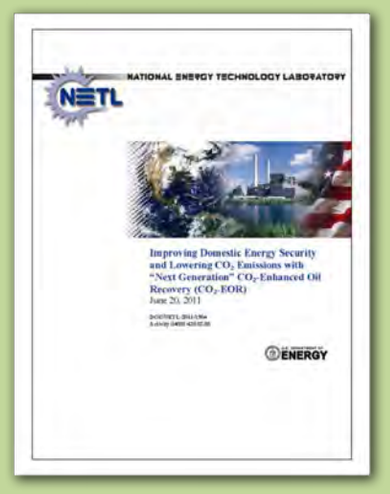
Regional Evaluation for a Specific Site	Site Selection & Characterization	Permitting	Operations	Post-Injection Monitoring	Long-Term Stewardship
Negative Cash Flow			Positive Cash Flow Injection Fee	Negative Cash Flow	Trust Fund Covers Costs
• Volume of emissions to store and pore space needed. • Geologic, geophysical, engineering, financial, and social. • Identify several prospective sites. • Begin assembly of acreage block	• Assemble/acquire new data. • Drill new well(s) & acquire seismic. • Get necessary permits. • Finish assembling acreage block. • Prepare required plans for Class VI permit. • Front-end engineering design for site. • Establish financial responsibility.	• Submit all plans and financial responsibility for permit application. • Approval to drill injection wells; State approves site permit. • Drill injection wells, incorporate new data in plans (e.g., AoR) and present to Director of EPA. • Injection operations approved. • Have 180 days to submit monitoring, reporting and verification (MRV) plan per Subpart RR regulations.	• Finish construction of surface facilities and MVA grid. • Begin injection of captured CO_2. • Follow plans, AoR every 5 years, annual reporting. • Annual mechanical integrity testing. • Drill new monitoring wells/perform corrective action as plume expands. • Plug and abandon (P&A) injection wells per plan. • Some financial responsibility instruments released.	• Update & present post-injection site care & site closure plan to Director. • Apply for reduced time period. • Follow Post-Injection Site Care (PISC) & site closure plan. • Plugged and abandoned all wells, restore sites. • Release of financial responsibility instruments.	• Another entity accepts long-term stewardship, oversees trust fund, pays site costs, settles all claims.
0.5 to 1 year	3+ years	2+ years	30 to 50 years	10 to 50+ years	Post Closure

Enhanced Oil Recovery (EOR) Class II

Prospect Screening	Facility/Field Design	Facility/Field Construction	Operations
Negative Cash Flow			Positive Cash Flow Oil & Gas Sales
• Technical and Economic Evaluation: 1. Reservoir & recoverable oil. 2. Facilities & costs.	• Wells, processing plant, pipelines, pattern development, etc. • Permitting, unitization. • Contract for CO_2.	• Drill/workover wells, build plant, install pipelines, connect with CO_2 source, etc.	• Begin injection of CO_2. • Production of oil, gas, CO_2, and water; gas & fluid separation & processing. • Recycling of CO_2. • Operation and maintenance (O&M). • Closeout. • P&A wells at end.
1 to 2 years			20 to 50 years

CO_2-EOR Resource Assessment

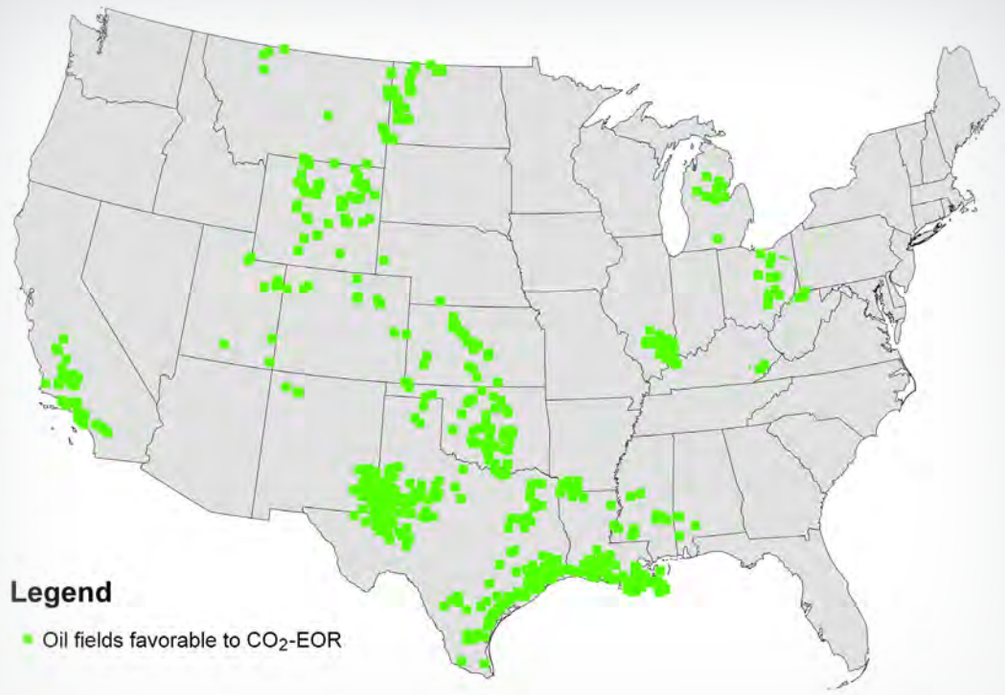
Advanced Resources International, Inc., (ARI) has prepared an NETL-sponsored assessment on the potential for additional recovery of crude oil and the corresponding mass of CO_2 that can be stored by applying CO_2-EOR to oil-bearing formations underlying the United States. A proprietary database containing the oil properties and geologic characteristics of 1,800 onshore reservoirs and more than 4,000 offshore reservoirs was used. The simulations for this assessment were conducted using the CO_2 Prophet Model, a screening tool that uses advanced computational techniques to model CO_2, water, and oil flows between injection wells and producing wells and estimates the magnitude and timing of oil production.



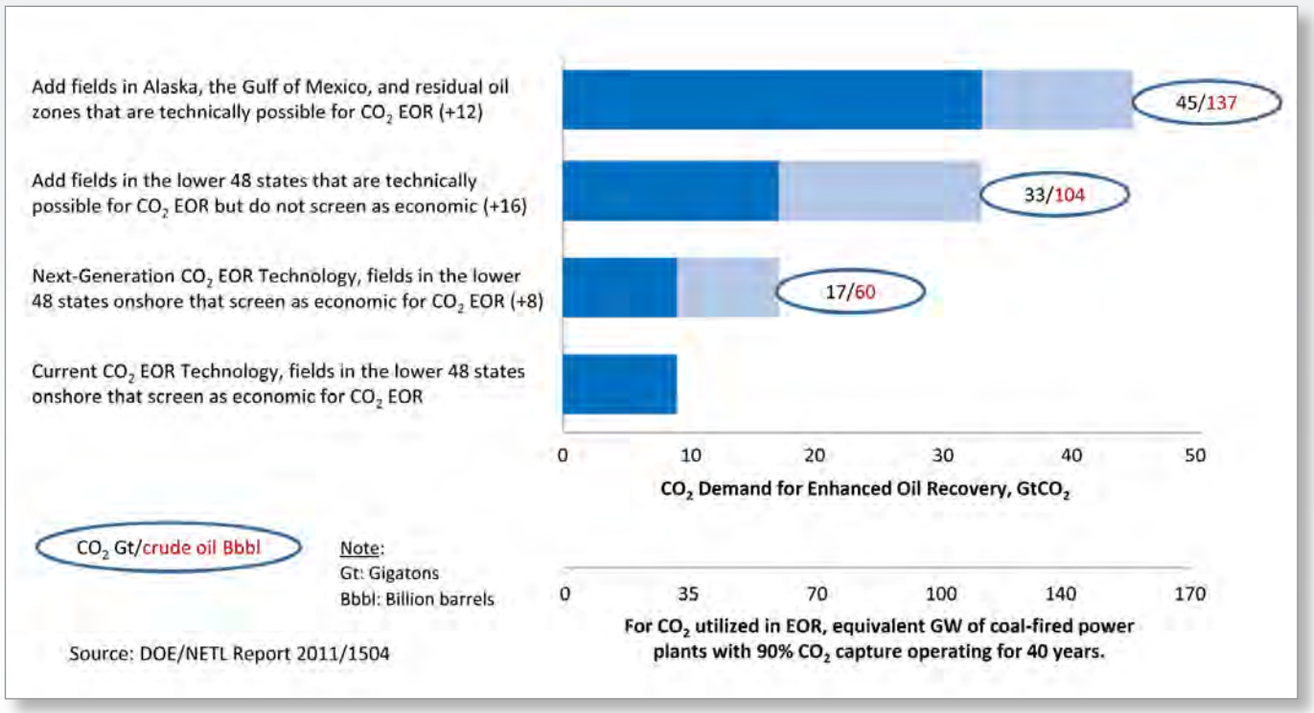
Improving Domestic Energy Security and Lowering CO_2 Emissions with "Next Generation" CO_2-Enhanced Oil Recovery (CO_2-EOR)

The figure to the right summarizes the results of this assessment based on today's technology (cost of CO_2 at $40/metric ton and the market price for crude oil at $85/bbl), the continental United States holds onshore an estimated resource of economically recoverable oil of 24 billion barrels (Bbbl). This level of additional crude oil recovery presents a potential demand for and subsequent storage of approximately 9 billion metric tons of CO_2. Under a case with "next generation" CO_2-EOR technology, the economic resource recovery value increases significantly to 60 billion barrels of oil, and demand for and potential storage of CO_2 increases to 17 billion metric tons. If one considers conventional oil-bearing formations where CO_2-EOR is technically possible but not economic (e.g., highly-fractured, low permeability, lower than minimum miscibility pressure, or other characteristics that make a CO_2 flood relatively difficult), the potential for crude oil recovery increases to 104 billion barrels of oil while demand for and potential storage of CO_2 demand increases to 33 billion metric tons.

The estimated technical recovery potential for CO_2-EOR can be increased further by including oil-bearing formations in Alaska, the offshore Gulf of Mexico, and residual oil zones. NETL is funding analyses to refine and improve the estimates for technical and economic resources for non-conventional CO_2-EOR settings.



Oil-bearing formations favorable for CO_2-EOR, onshore lower 48 states. (Source: ARI disaggregated database, Ventex Velocity Suite Database).



NETL/ARI estimates for CO_2 storage potential and additional crude oil recovery potential for oil-bearing formations in the United States. Source: "Improving Domestic Energy Security and Lowering CO_2 Emissions with Next-Generation CO_2 Enhanced Oil Recovery" (NETL 2011/1504, June 2011).

Intra-Agency Coordination

Through ongoing engagement with key stakeholders to help identify high priority technology areas for advancement, DOE, via SubTER and NRAP, has developed a comprehensive, focused, and coordinated R&D strategy. This coordinated strategy provides DOE research and program managers the ability to look across similar activities, quickly fill critical gaps in research, and archive results in a corporate database, all of which will promote the dissemination of important information for current and future researchers.

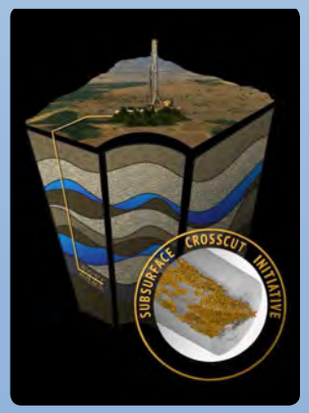
National Risk Assessment Partnership

The National Risk Assessment Partnership (NRAP)—an initiative within FE and led by NETL—applies DOE's core competency in science-based prediction for engineered–natural systems to the long-term storage of CO_2. NRAP members include five national DOE laboratories that have been conducting collaborative research for the Carbon Storage Program for many years: NETL, Lawrence Berkeley National Laboratory, Lawrence Livermore National Laboratory, Los Alamos National Laboratory, and the Pacific Northwest National Laboratory. NRAP has also joined international efforts to develop the risk assessment tools needed for safe, permanent geologic CO_2 storage. The NRAP program receives input from industry, government, non-government organizations, and academia regarding research needs for large-scale CO_2 storage deployment.

The science-based prediction of engineered–natural systems is a core competency that crosscuts many of today's energy challenges. Over decades, DOE has built a unique set of resources for predicting how these complex and heterogeneous systems behave under extreme conditions and over large ranges in time. NRAP's primary objective is to develop a defensible, science-based methodology and platform for quantifying risk profiles at most types of CO_2 storage sites to guide decision making and risk management. NRAP will also develop monitoring and mitigation protocols to reduce uncertainty in the predicted long-term behavior of a site. To accomplish these goals, researchers listen to industry and regional partnerships to make sure their research is relevant to market needs and working toward solving real-world problems associated with the risk assessment of CO_2 storage.

Subsurface Technology and Engineering Research, Development, and Demostration (SubTER) Tech Team

DOE established the SubTER Tech Team as an integrated platform across DOE subsurface interests to address crosscutting challenges associated with using the subsurface for energy extraction and storage purposes. The SubTER Tech Team includes representatives of all of DOE's applied technology offices, as well as several other offices focused on policy, research, and development. The functions of the DOE SubTER Tech Team include identifying subsurface challenges and advocating solutions, identifying potential crosscutting subsurface initiatives, facilitating both intra-departmental and interagency collaboration of crosscutting subsurface R&D activities, and engaging industry stakeholders operating in the subsurface.



Interagency and State Coordination

DOE collaborates with a number of Federal and State agencies to help inform regulatory issues that have not yet been addressed for wide-scale deployment of CCS technologies. The objective of these efforts is to provide research results that help inform regulatory decision making. In addition to collaboration through the Interagency Task Force on CCS, the Carbon Storage Program interacts with the U.S. EPA, the U.S. Department of Interior's Bureau of Ocean Energy Management (BOEM), Bureau of Land Management (BLM) and U.S. Geological Survey (USGS), the Interstate Oil and Gas Compact Commission (IOGCC), Ground Water Protection Council (GWPC), and the U.S. Department of Transportation (DOT) on issues related to CO_2 storage and transport. The methodologies developed and data collected by the program support the efforts of BLM, BOEM, and USGS as they determine the potential role for Federal lands in developing CCS opportunities both onshore and offshore.

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.
- Collaborating with USGS on storage capacity resource assessment.
- Assisting BOEM with developing rules for offshore CO_2 injection.
- Examining the legal and regulatory framework for CO_2 storage with IOGCC.
- Examining State regulatory program data management for CO_2 storage with GWPC.
- Interacting with EPA and State regulatory agencies mostly through the permitting process by the RCSPs and small-scale field injection projects. EPA participates as an expert panelist for the IEAGHG R&D Programme Peer Review.
- Collaborating with DOT, the Federal Energy Regulatory Commission, National Association of Regulatory Utility Commissioners, and Surface Transportation Board to examine the regulatory framework for CO_2 pipeline siting, operation, and tariffs.
- Participating in the IOGCC Pipeline Transportation Task Force on CO_2 pipelines for carbon storage. More than 20 States and Canadian Provinces are IOGCC members.
- All of this work supports the Interagency Task Force on CCS.

Knowledge Sharing Efforts

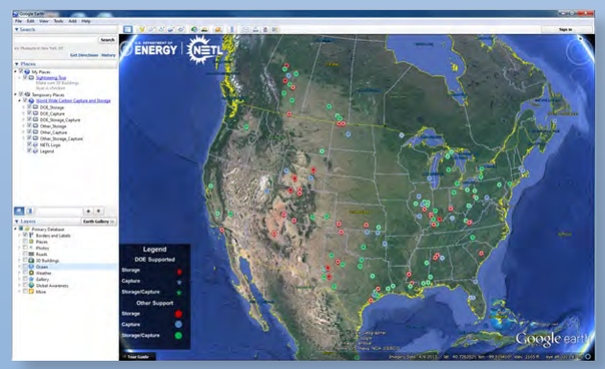
DOE understands that knowledge sharing among various stakeholders is essential to promote the commercialization of CCS technologies. In addition to the series of past and future *Carbon Storage Atlases*, NETL promotes information and knowledge sharing through various avenues, including the development and distribution of Best Practices Manuals (BPMs), the development of online tools and resources, involvement in CCS working groups, and other public outreach and education efforts (e.g., the Carbon Storage Newsletter). NETL has been actively disseminating knowledge and developing the workforce required for the future through seven Regional Technology Training Centers that focus on training personnel for future implementation of CCS technology.

Best Practices Manuals

One of NETL's main initiatives to promote information and knowledge sharing is the development of a series of BPMs that outline uniform approaches to address a variety of CCS-related issues and challenges. Developing best practices (or reliable and consistent standards and operational characteristics for CO_2 collection, injection, and storage) is essential for providing the basis for a legal and regulatory framework and encouraging widespread global CCS deployment. These BPMs provide recommended approaches for monitoring, verification, accounting (MVA), and assessment; public outreach and education; geologic storage formation classifications; site screening, selection, and characterization; simulation and risk assessment; well construction, operations, and closure; and terrestrial sequestration.

NETL's CCS Database – Version 5

NETL's CCS Database includes active, proposed, and terminated CCS projects worldwide. Information in the database regarding technologies being developed for capture, evaluation of sites for CO_2 storage, an estimation of project costs, and anticipated dates of completion is sourced from publicly available information. As of November 2014, the database contained 274 CCS projects worldwide. The 274 projects include 69 capture, 60 storage, and 145 capture and storage in more than 30 countries across 6 continents. While several of the projects are still in the planning and development stage, 128 are actively capturing and/or injecting CO_2.



Energy Data eXchange

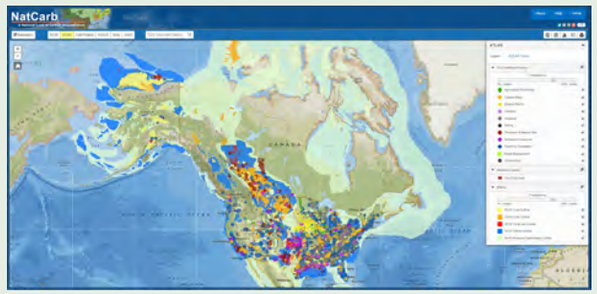
NETL maintains the EDX as an online system to support internal coordination and collaboration as well as timely tech transfer of data-driven products across NETL's research portfolios. EDX coordinates historical and current data and information from a wide variety of sources to facilitate access to research that crosscuts multiple NETL projects and programs. EDX provides external access to technical products and data published by NETL-affiliated research teams. NETL-affiliated researchers can use EDX's Collaborative Workspaces to coordinate and share work with a variety of organizations and institutions in a secure environment. NATCARB provides the *Atlas* data to EDX.

National Carbon Sequestration Database and Interactive Viewer

NATCARB aims to construct a national carbon cyberinfrastructure by assembling the data required to address technical and policy challenges of CCS. The NATCARB database is assembled by collaborative partnerships with RCSPs and ARRA-funded site characterization projects. Other publicly available data repositories are used to enhance its capabilities.

NATCARB provides access to datasets required for CCS deployment. It displays information about CO_2 stationary sources and CO_2 storage resource data. Data are generated and maintained at each RCSP or the publicly available data warehouses.

The NATCARB interactive viewer addresses broad needs of all users and provides easy data access on different platforms ranging from desktops to mobile platforms such as tablets. The general public can access the viewer and query the database for a wide variety of information on different CCS projects ranging from emission and storage potential to brine data for geochemistry. The national estimates on emission of CO_2 stationary sources and the geologic storage resources are available for download.



DOE'S CARBON STORAGE PROGRAM

Fort Nelson

Zama Oilfield

Weyburn-Midale
Courtesy of Cenovus Energy

Aquistore
Courtesy of Aquistore Project

CarbFix
Courtesy of Orkuveita Reykjavikur

PROJECT LOCATION	OPERATIONS	RESERVOIR TYPE	OPERATOR/ PARTNER	DOE CONTRIBUTION
CarbFix Europe, Iceland	CO_2 stream from Hellisheidi geothermal power plant	Saline Basalt	Reykjavik Energy	Supporting Columbia University Lamont-Doherty Earth Observation to test tracer methods to assess trapping mechanisms in basalt formations.

Global Collaborations

DOE is partnering with many international organizations that are advancing carbon storage research at projects located throughout the world. These collaborative learning opportunities will help to advance CCS technologies at a lower cost and on a shorter time frame. The benefits of U.S. scientists' participation range from opportunities to field test innovative technologies at commercial- and large-scale CCS operations around the world to providing U.S. expertise on multinational CCS investigative R&D teams. Supporting these projects directly enhances U.S. efforts to develop technologies and tools to meet the strategic goals of the Carbon Storage Program's Core R&D Element.

DOE's **global collaborations** also include participation in or relationships with the IEAGHG R&D Programme, the Global Carbon Capture and Storage Institute (GCCSI), the Carbon Sequestration Leadership Forum (CSLF), the North American Carbon Storage Atlas Partnership (NACAP), and the U.S.-China Clean Energy Research Center (CERC). These collaborations provide a means to encourage the transfer of technical lessons learned between industry and academia to facilitate the development and adoption of new technologies in the field and to train personnel in the United States for future careers in the CCS industry throughout the world.

PROJECT LOCATION	OPERATIONS	RESERVOIR TYPE	OPERATOR/ PARTNER	DOE CONTRIBUTION
Weyburn-Midale North America, Canada, Saskatchewan	2.8 million metric tons CO_2 /year Commercial in 2000	Oilfield Carbonate EOR	Cenovus, Apache, Petroleum Technology Research Centre	DOE is a lead sponsor of the IEAGHG research project and U.S. scientists test multiple monitoring and simulation technologies.
Zama Oilfield North America, Canada, Alberta	360,647 tons of CO_2 injected during Phase III and 29,966 tons of CO_2 injected during Phase II	Oilfield Carbonate EOR	Apache (RCSP)	Supported the PCOR Partnership to conduct monitoring and reservoir modeling of CO_2 injection into pinnacle reefs.
Fort Nelson North America, Canada, British Columbia	Anticipated injection of >1 million metric tons CO_2 /year 1.8 million metric tons acid gas/year Large-scale demonstration	Saline Carbonate Formation	Spectra Energy (RCSP)	Supporting the PCOR Partnership to conduct monitoring and reservoir modeling studies.
Aquistore North America, Canada, Saskatchewan	Up to 1,000 metric tons CO_2 /day	Saline Sandstones	Petroleum Technology Research Centre	Supporting LBNL in performing seismic testing and distributed acoustic sensor monitoring, as well as the PCOR Partnership performing reservoir modeling and simulation.

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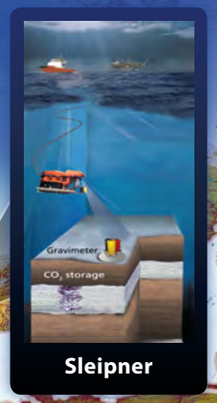
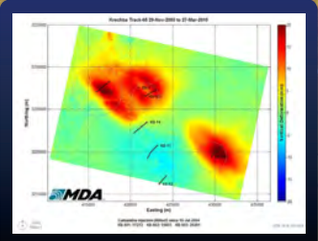


Sleipner

Snøhvit CO_2 Storage

CO_2 SINK, Ketzin
Courtesy of Ketzin Project



In Salah Gas

PROJECT LOCATION	OPERATIONS	RESERVOIR TYPE	OPERATOR/ PARTNER	DOE CONTRIBUTION
Sleipner Europe, Norway, North Sea	1 million metric tons CO_2/year Commercial in 1996	Saline Marine Sandstone	StatoilHydro	Supporting Indiana University for reservoir modelling and the Scripps Institute of Oceanography for past time-lapse gravity surveys.
Snøhvit CO_2 Storage Europe, Norway, North Sea	700,000 metric tons CO_2/year Commercial in 2008	Saline Marine Sandstone	StatoilHydro	Supported LLNL to simulate geomechanical conditions of the reservoir and caprock with a focus on probabilistic analysis of the potential for fault reactivation and dynamic well test analysis and continuous inversion of gage data.
CO_2SINK, Ketzin Europe, Germany	60,000 metric tons CO_2Demonstration 2008	Saline Sandstone	GeoForschungsZentrum, Potsdam	Supporting LBNL to deploy downhole monitoring technology based on seismic and thermal perturbation sensors and Multi-Phase Technologies, LLC, to conduct electromagnetic monitoring.

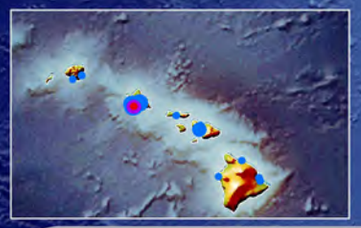
PROJECT LOCATION	OPERATIONS	RESERVOIR TYPE	OPERATOR/ PARTNER	DOE CONTRIBUTION
In Salah Gas Africa, Algeria	3.8 million metric tons CO_2 injected Commercial from 2004 – 2008	Gasfield Sandstone	BP, Sonatrach, StatoilHydro	Supporting LLNL and LBNL to test field and remote sensing monitoring technologies and modeling geomechanical and geochemical reservoir processes.
Otway Basin Australia, Victoria	65,000 metric tons CO_2 Stage I 2008, Stage II 2011	Gasfield and Saline Sandstone	CO_2CRC	Supporting LBNL to test multiple monitoring technologies at depleted gasfield and saline formations, including geochemical U-tube sampling and tracer studies, and seismic fiber optic acquisition.
Ordos Basin Asia, China	100,000 metric tons CO_2 /year	Ordos Basin	Shenhua Coal	Supporting West Virginia University and LLNL in assessment of capacity for storage, and simulation of hydrogeologic and geochemical reservoir conditions.

U.S.-CHINA CLEAN ENERGY RESEARCH CENTER

Ordos Basin

Otway Basin
Courtesy of CO_2CRC

National Perspectives



Atlas V CO_2 Stationary Sources

- Agricultural Processing
- Cement Plant
- Electricity
- Ethanol
- Fertilizer
- Industrial
- Petroleum / Natural Gas
- Refineries / Chemical
- Unclassified

Annual CO_2 Emissions (Metric Tons)

- 10,000 - 250,000
- 250,001 - 500,000
- 500,001 - 750,000
- 750,001 - 10,000,000
- > 10,000,000

0 125 250 500 750 1,000 Kilometers

0 75 150 300 450 600 Miles

NETL

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Disclaimer - This map was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, expressed or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights.

CO_2 Stationary Source Emission Estimates by RCSP/Region*

RCSP/Region	Number of Sources	CO_2 Emissions (million metric tons per year)
BSCSP	301	115
MGSC	380	267
MRCSP	1,308	604
PCOR**	946	522
SECARB	1,857	1,022
SWP	779	326
WESTCARB**	555	162
U.S. Non-RCSP***	232	53
Total	**6,358**	**3,071**

* Current as of November 2014

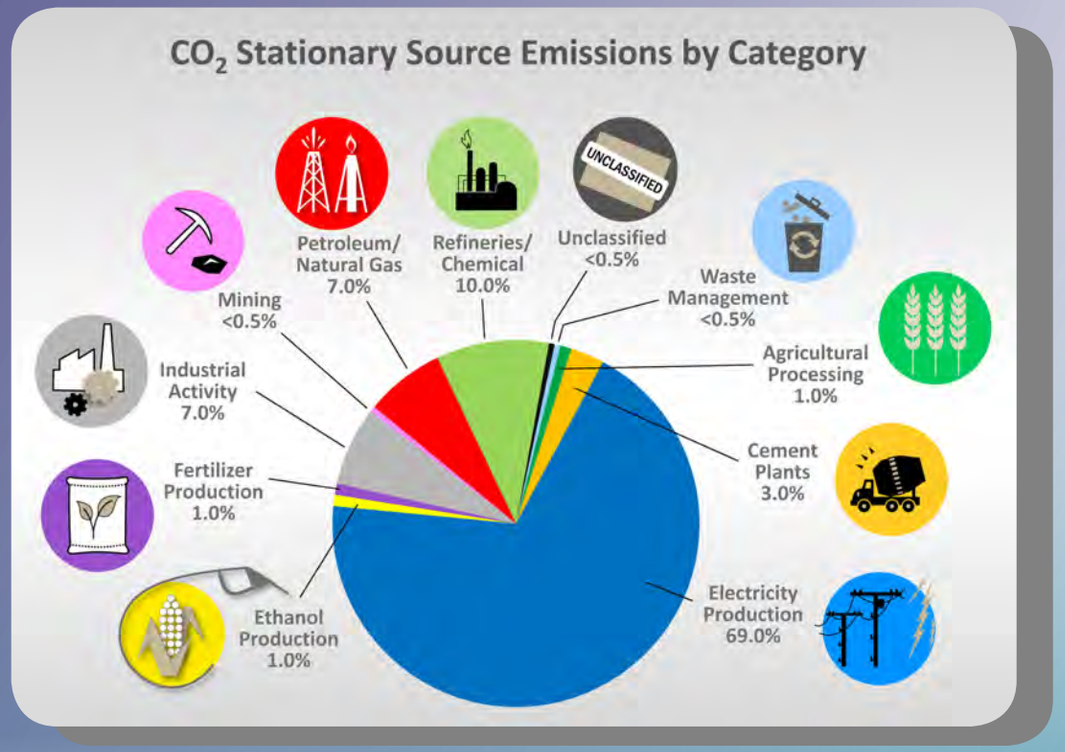
** Totals include Canadian sources identified by the RCSP.

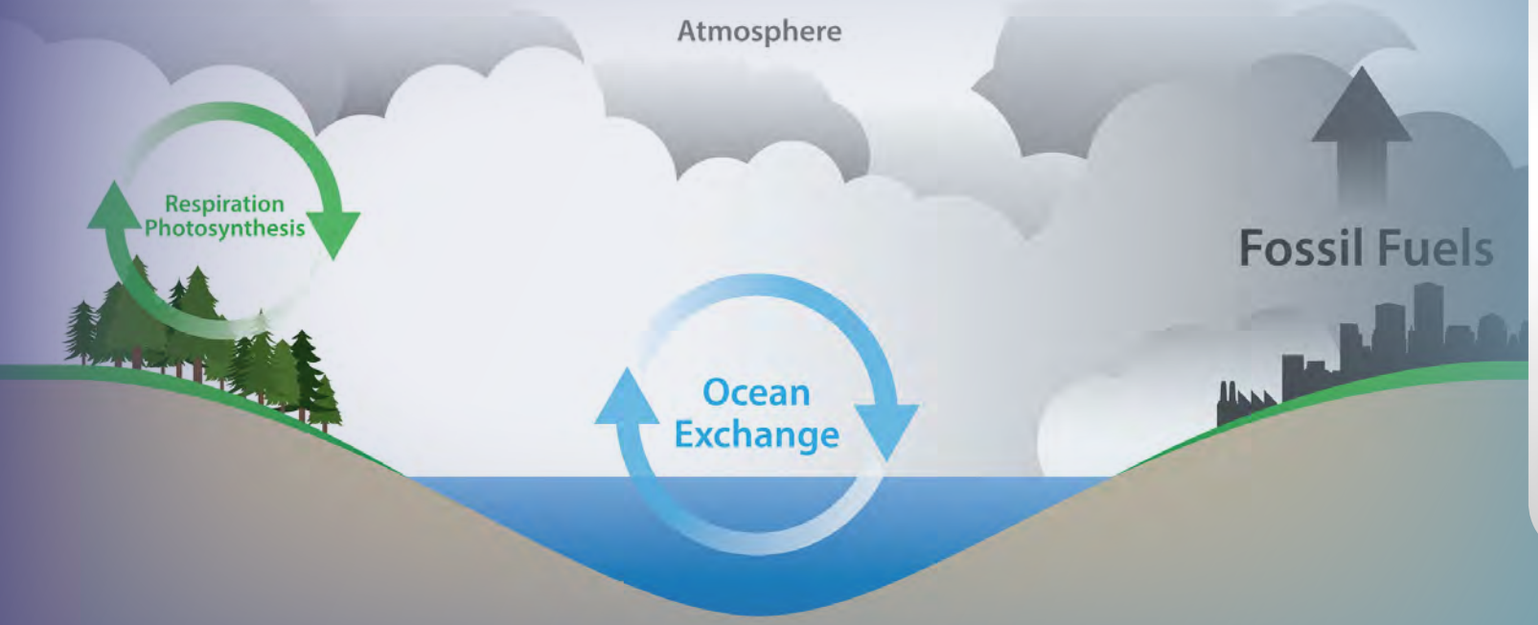
*** As of July 2015, "U.S. Non-RCSP" includes Connecticut, Delaware, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont, and Puerto Rico.

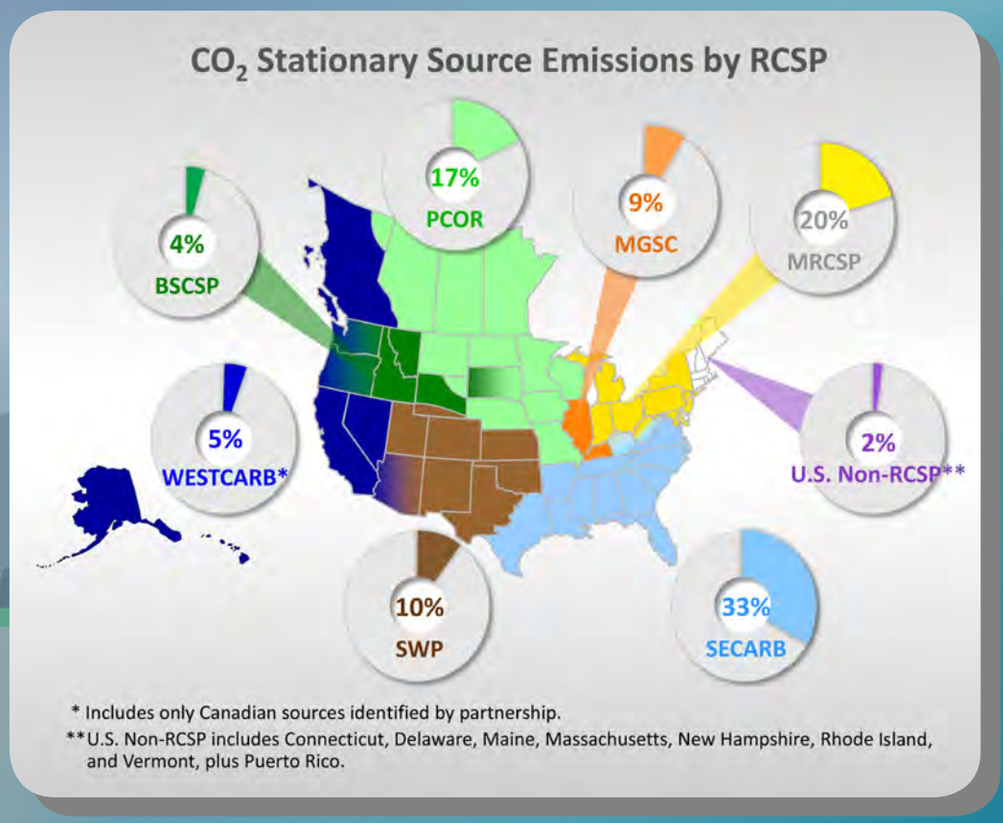
CO_2 SOURCES

There are two types of CO_2 emission sources: natural and anthropogenic (man-made). Natural sources include respiration from animals and plants, volcanic eruptions, forest and grass natural fires, decomposition of biomass material (plants and trees), and naturally occurring sources in geologic formations. Anthropogenic sources result from human activity, including burning fossil fuels for electricity generation, cement production and other industrial processes, deforestation, agriculture, and changes in natural land usage. Although CO_2 emissions from natural sources are estimated to be greater than the anthropogenic sources, natural sources are believed to maintain equilibrium through a process known as the global carbon cycle, in which carbon is exchanged between the land, ocean, and atmosphere. This natural system keeps CO_2 levels in the atmosphere stable over time. Increases in anthropogenic emissions over the last 200 years have led to an overall increase in the concentration of CO_2 and other GHGs in the atmosphere. While nature's carbon cycle keeps CO_2 levels in balance, human activity, mostly resulting from burning fossil fuels, produces more CO_2 than nature can absorb. One important mitigation option that can help offset this imbalance is CCS.

DOE has documented 6,358 stationary CO_2 sources with total annual emissions of approximatively 3,071 million metric tons of CO_2. For details on large stationary sources of CO_2 by State/Province, see Appendix C. For more information on the methodologies used to generate these emission estimates, please see Appendix A.







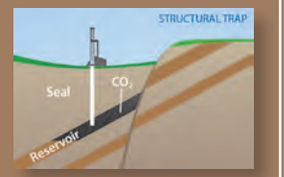
SEDIMENTARY BASINS

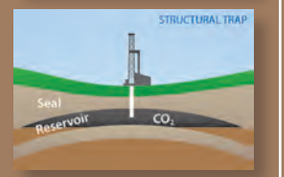
DOE has identified and examined the location of potential CO_2 injection formations in different sedimentary basins throughout the United States. These sedimentary basins collected sediments that compacted under pressure over time to become sedimentary rocks. If these sedimentary rocks are porous or fractured, they can be saturated with oil, gas, or brine (saline water with a high total dissolved solids concentration—a measure of the amount of salt in water). If the sedimentary rock is permeable (e.g., many sandstones), it could be a target for CO_2 injection. If it is impermeable (e.g., shales), it could act as a confining zone to prevent CO_2 migration. The presence of both a reservoir with sufficient injectivity and a seal to prevent migration are necessary conditions for a CO_2 storage site.

Brine is water that contains appreciable amounts of salts that have either been leached from the surrounding rocks or from seawater that was trapped when the rock was formed. The U.S. EPA has determined that a saline formation used for CO_2 storage must have at least 10,000 parts per million of total dissolved solids. Most drinking water supply wells contain a few hundred parts per million or less of total dissolved solids. Oil and natural gas reservoirs are often saline formations that have traps and seals that allowed oil and gas to accumulate over millions of years. Many oil and gas fields contain stacked formations (different reservoirs over top of each other) with characteristics such as good porosity, which can make for excellent multiple target locations at one geologic storage site.

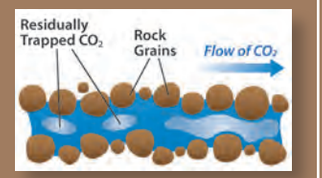
CO_2 TRAPPING

Trapping refers to the way the CO_2 remains underground in the location where it was injected. Four main mechanisms trap the injected CO_2 in the subsurface. Each of these mechanisms play a role in how the CO_2 remains trapped in the subsurface.

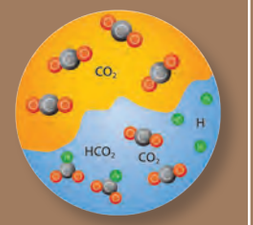




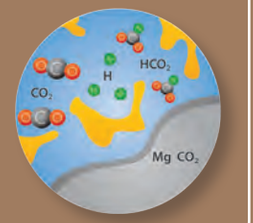
- **Structural Trapping**—The physical trapping of CO_2 in the rock and the mechanism that traps the greatest amount of CO_2.



- **Residual Trapping**—The CO_2 that remains trapped in the pore space between the rock grains as the CO_2 plume migrates through the rock.



- **Solubility Trapping**—A portion of the injected CO_2 will dissolve into the brine water that is present in the pore spaces within the rock.



- **Mineral Trapping**—A reaction that can occur when the CO_2 dissolved in the rock's brine water reacts with the minerals in the rock.

Atlas V
Sedimentary Basins
Sedimentary Basins

0 125 250 500 750 1,000
Kilometers
Miles
0 75 150 300 450 600

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OIL RESERVOIRS

Oil reservoirs are porous rock formations (usually sandstones or carbonates) containing crude oil that has been physically trapped. There are two main types of physical traps: (1) stratigraphic traps, created when changes have occurred in rock types, and (2) structural traps, in which the rocks have been folded or faulted to create a trapping mechanism. Oil reservoirs are ideal geologic storage sites because they have held the crude oil for thousands to millions of years and thus should have conditions suitable for CO_2 storage. Furthermore, their architecture and properties are well known as a result of exploration for and production of these hydrocarbons. In addition, due to the industrialization of these sites, infrastructure probably exists for CO_2 transportation and storage.

Traditionally, oil is extracted from a reservoir in up to three different phases. The primary recovery phase uses the natural pressure in the reservoir to push the oil to the production well. This process usually accounts for 10 to 15 percent oil recovery. In order to increase this recovery, a process called enhanced oil recovery (EOR) is usually started. EOR involves injecting fluids to sweep the oil to production wells. The secondary recovery phase usually involves injecting water to increase the reservoir pressure and displace the oil toward producing wells. This process produces an additional 15 to 25 percent of the original oil. Together, these two phases account for the recovery of 25 to 40 percent of the original oil, leaving up to two-thirds of the oil in the reservoir. There are many kinds of tertiary recovery, one of which involves injecting CO_2 into reservoirs to increase oil recovery. This method has been carried out for more than 40 years. When CO_2 is injected into an oil reservoir, it raises the reservoir pressure and increases the oil mobility, making it easier for the oil to reach producing wells. This method, called CO_2-EOR, is an attractive option for CO_2 storage because, as part of the conventional CO_2-EOR operations, a portion of the CO_2 is naturally stored and referred to as associated storage.

The utilization of CO_2 for EOR in some portions of oil fields could provide the potential for low carbon oil. One promising target is the residual oil zone (ROZ). ROZs have the potential to store more CO_2 than is emitted by the use of the produced oil. In all oil fields the main production zones are underlain by an ROZ, in which a substantial volume of oil is present, but the oil content is too low to be produced by conventional processes. In recent years research projects have attempted to utilize CO_2 to extract oil from ROZs, with varying amounts of technical and economic success. Additional research and analysis is merited to better understand the viability of this emission reduction strategy, including assessment of the full life cycle emissions profile and consideration of the anthropogenic CO_2 source.

While assessment continues, DOE has documented approximately 186 to 232 billion metric tons of CO_2 storage resource in oil and natural gas reservoirs. For details on oil and natural gas reservoir CO_2 storage resource by State/Province, see Appendix C. For more information on the methodologies used to estimate this potential, please see Appendix B.

Atlas V
Oil Reservoirs

Oil Reservoirs

EOR operations in Michigan. Courtesy of MRCSP.

CO_2 Storage Resource Estimates for Oil and Natural Gas Reservoirs by RCSP*

RCSP	Low	Medium	High
	Billion Metric Tons	Billion Metric Tons	Billion Metric Tons
BSCSP	<1	<1	1
MGSC	<1	<1	<1
MRCSP	9	14	26
PCOR	2	4	9
SECARB	27	34	41
SWP	144	147	148
WESTCARB	4	5	7
Total	**186**	**205**	**232**

* Current as of November 2014; Medium = p50

0 125 250 500 750 1,000 Kilometers

0 75 150 300 450 600 Miles

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NATURAL GAS RESERVOIRS

Natural gas reservoirs are similar to oil reservoirs in that they are porous rock formations containing hydrocarbons (natural gas) that have been physically trapped in stratigraphic or structural traps. Natural gas reservoirs are ideal geologic storage sites because they have held hydrocarbons for thousands to millions of years, and their architecture and properties are well known as a result of exploration and production activities. Natural gas can occur in oil reservoirs. This natural gas is referred to as "associated-dissolved" natural gas and occurs either as free gas (associated gas) or as gas in solution with the crude oil (dissolved gas). Natural gas also occurs in reservoirs without significant amounts of oil, and this gas is referred to as "non-associated" natural gas. Historically in the United States, more than twice as much non-associated gas has been produced compared to associated-dissolved gas from oil reservoirs.

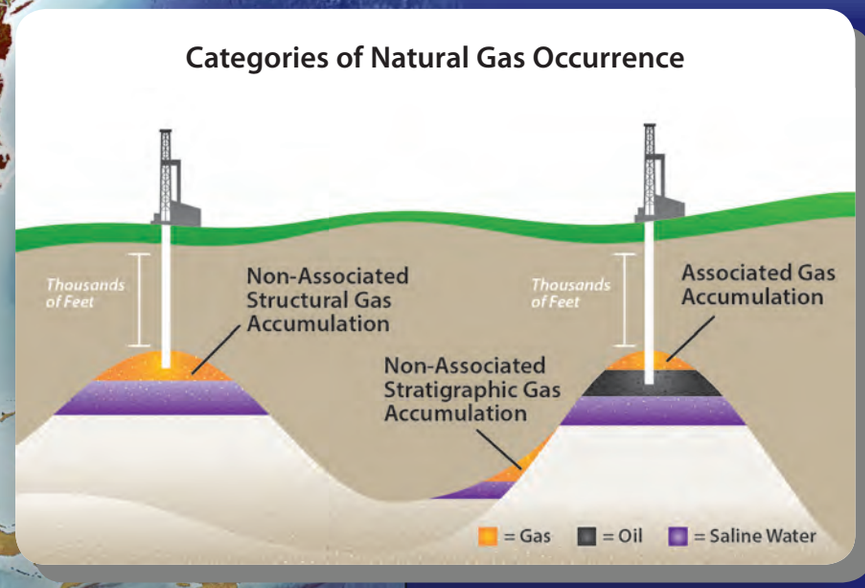
Recovery factors are higher in gas fields than they are in oilfields. Typical recovery factors for gas are approximately 50 to 80 percent. Due in part to these higher recovery factors, there is no conventional commercial enhanced recovery technology counterpart for gas reservoirs similar to that of oil reservoirs. Some research studies have concluded that it is technically feasible to use CO_2 to enhance gas recovery by increasing reservoir pressure and displacing natural gas toward producing wells.

To meet fluctuating demand, natural gas produced from gas reservoirs is transported by pipeline and re-injected into interim storage facilities. In many places in the United States these interim storage facilities are saline formations. The experience and technologies associated with the commercial saline formation storage of natural gas are applicable to CO_2 storage. A few research studies have been carried out to explore the possibility of using CO_2 in place of natural gas as the cushion gas needed to maintain pressures in saline storage facilities.

While assessment continues, DOE has documented approximately 186 billion metric tons to more than 232 billion metric tons of CO_2 storage resource in oil and natural gas reservoirs. For details on oil and natural gas reservoir CO_2 storage resource by State/Province, see Appendix C. For more information on the methodologies used to estimate this potential, please see Appendix B.

Atlas V
Natural Gas Reservoirs

Natural Gas Reservoirs



0 125 250 500 750 1,000 Kilometers

0 75 150 300 450 600 Miles

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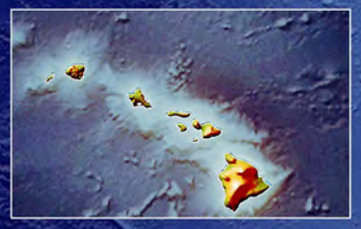
UNMINEABLE COAL

Coal that is considered unmineable because of geologic, technological, or economic factors has the potential for CO_2 storage. These factors include coal that is too deep, too thin, or lacking the internal continuity to be economically mined with today's technologies. Coal preferentially adsorbs CO_2 over methane, which is naturally found in coal seams, at a ratio of 2 to 13 times. This property, known as adsorption trapping, is the basis for CO_2 storage in coal seams. Typically, methane gas is recovered from coal seams by dewatering and depressurization, but this can leave some methane trapped in the seam. The process of injecting and storing CO_2 in unmineable coal seams to enhance methane recovery is called enhanced coalbed methane recovery. Enhanced coalbed methane recovery parallels EOR because it provides an economic benefit from the recovery and sale of the methane gas, helping to offset the cost of CO_2 storage.

The coal must have sufficient permeability, which controls injectivity, for CO_2 storage. Coal permeability depends on the effective stress and usually decreases with increasing depth. Furthermore, studies have shown that CO_2 injection can impact coal permeability and injectivity. Carbon dioxide does not need to be in the supercritical (dense phase) state for it to be adsorbed by coal, so CO_2 storage in coals can take place at shallower depths (at least 200 meters deep) than storage in oil and natural gas reservoirs and saline formations (at least 800 meters depth).

While assessment continues, DOE has documented approximately 54 billion metric tons to more than 113 billion metric tons of potential CO_2 storage resource in unmineable coal. For details on unmineable CO_2 storage resource by State/Province, see Appendix C. For more information on the methodologies used to estimate this potential, please see Appendix B.



Atlas V
Unmineable Coal

- Assessed
- Non-Assessed

Skyland coalbed in Kentucky. Courtesy of MRCSP.

CO_2 Storage Resource Estimates for Unmineable Coal by RCSP*

RCSP	Low	Medium	High
	Billion Metric Tons	Billion Metric Tons	Billion Metric Tons
BSCSP	<1	<1	<1
MGSC	2	3	3
MRCSP	<1	<1	<1
PCOR	7	7	7
SECARB	33	51	75
SWP	<1	1	2
WESTCARB	11	17	25
Total	**54**	**80**	**113**

* Current as of November 2014; Medium = p50

0 125 250 500 750 1,000 Kilometers

0 75 150 300 450 600 Miles

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SALINE FORMATIONS

Saline formations are layers of sedimentary porous and permeable rocks saturated with salty water called brine. These formations are fairly widespread in both onshore and offshore sedimentary basins throughout North America and have potential for CO_2 storage. Saline formation trapping mechanisms include solubility trapping, mineral trapping, structural trapping, and residual trapping (see page 24 for more information). It is important that a regionally extensive confining zone (often referred to as caprock or seal) overlies the porous rock layer.

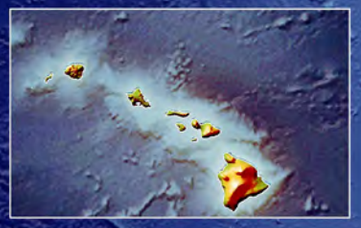
Saline formations represent an enormous potential for CO_2 storage, and recent project results suggest that they can be used as reliable, long-term storage sites. Saline formation storage lacks the economic incentives of oil and natural gas reservoirs or unmineable coal storage; however, they could serve as buffer storage for EOR operations.

While assessment continues, DOE has documented approximately 2,379 billion metric tons to more than 21,633 billion metric tons of CO_2 storage resource in saline formations. For details on saline formation CO_2 storage resource by State/Province, see Appendix C. For more information on the methodologies used to estimate this potential, please see Appendix B.

CO_2 Storage Resource Estimates for Saline Formations by RCSP*

RCSP	Low	Medium	High
	Billion Metric Tons	Billion Metric Tons	Billion Metric Tons
BSCSP	211	805	2,152
MGSC	41	163	421
MRCSP	108	122	143
PCOR	305	583	1,012
SECARB	1,376	5,257	14,089
SWP	256	1,000	2,693
WESTCARB	82	398	1,124
Total	**2,379**	**8,328**	**21,633**

* Current as of November 2014; Medium = p50



Atlas V Saline Formations

Assessed

Non-Assessed

Saline rock formations near Belfry, Montana. Courtesy of John Talbott, BSCSP.

0 125 250 500 750 1,000 Kilometers

0 75 150 300 450 600 Miles

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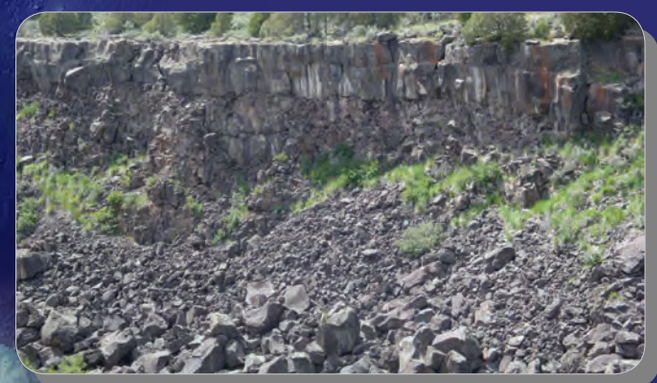
BASALT FORMATIONS

DOE is also investigating use of geologic formations of solidified lava, called basalt, as another potential CO_2 storage option. The relatively large amount of potential storage resource in basalts, along with their geographic distribution, makes them an important formation type for possible CO_2 storage, particularly in the Pacific Northwest and the southeastern United States. These formations have a unique chemical makeup that could potentially convert all of the injected CO_2 to a solid mineral form, thus isolating it permanently from the atmosphere.

The chemistry of basalts allows injected CO_2 to react with magnesium and calcium in the rocks to form the stable carbonate mineral forms of calcite and dolomite. DOE's current efforts are focused on enhancing and utilizing the mineralization reactions and increasing CO_2 flow within basalt formations. However, more research is needed to understand the time frames and actual chemical inputs and outputs of a basalt CO_2 injection.

Basalt outcrop in eastern Washington.
Courtesy of Sarah Koenigsberg.



An example of a basalt flow.
Courtesy of Travia McLing, INL.

Atlas V
Basalt Formations

Basalt Formations

0 125 250 500 750 1,000
Kilometers

0 75 150 300 450 600
Miles

NETL

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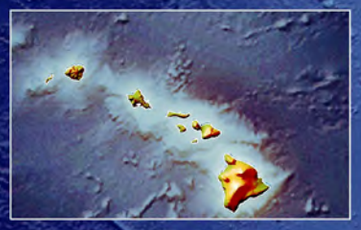
ORGANIC-RICH SHALE BASINS

Organic-rich shales are formed from silicate minerals, which are degraded into clay particles that accumulate over millions of years. The plate-like structure of these clay particles causes them to accumulate in a flat manner, resulting in vertical rock layers with extremely low permeability. Shales are most often used in geologic storage as a confining zone or caprock, though recent investigations have shown potential for select shale formations to be used for CO_2 storage.

Shales of interest for storage are formed from deposits of high-organic materials. During storage, CO_2 will preferentially absorb to mineral surfaces, releasing methane, while permanently locking the CO_2 in place. Recent technological advances in horizontal drilling and hydraulic fracturing have increased interest in the energy sector for natural gas production from organic-rich shales. With horizontal drilling and hydraulic fracturing, operators engineer porosity and permeability into organic-rich shales to create flow pathways. These technologies, coupled with the fact that CO_2 is preferentially adsorbed over methane, will improve the feasibility of using CO_2 for enhanced gas recovery in much the same way as enhanced coalbed methane recovery. While the additional engineering of the rocks would add to the cost, the potential for hydrocarbon production could potentially offset this increase.



Atlas V
Shale Basins

Shale Basins

New Albany Shale outcrop. Courtesy of MGSC.

0 125 250 500 750 1,000
Kilometers

Miles
0 75 150 300 450 600

NETL

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OFFSHORE CO_2 STORAGE POTENTIAL

Offshore geologic storage in the United States is currently being investigated for its potential to serve as one of the options for safe, long-term CO_2 storage. Offshore geologic CO_2 storage involves capturing CO_2 from a stationary emission source, transporting the CO_2 offshore via a sub-sea pipeline or ocean tanker, and injecting it into a geologic formation deep beneath the seabed where it will remain safely stored (isolated from the ocean water) for hundreds to thousands of years. However, there are a number of knowledge gaps for CO_2 storage in offshore geologic formations along the coastal margins of the United States, including limited characterization of offshore CO_2 storage potential and no experience in offshore CO_2 storage and monitoring.

Some assessments of offshore geologic CO_2 storage potential have been undertaken, but not through an organized initiative. The Department of Interior (DOI), BOEM has authority under the Energy Policy Act of 2005 and is in the process of developing regulations to govern outer continental shelf CCS projects, but at this time no regulations exist.

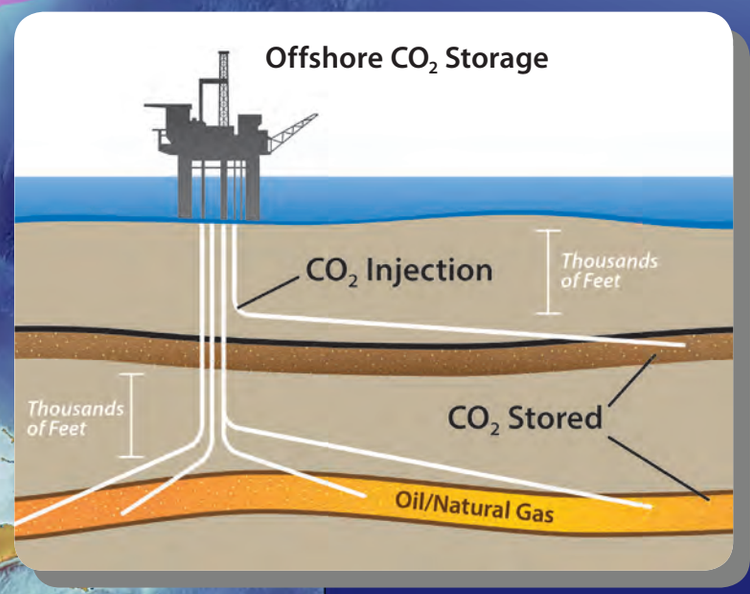
Offshore CO_2 storage offers an alternative opportunity for CO_2 storage to regions with limited onshore geologic storage.

The advantages of offshore CO_2 storage include, but are not limited to:

- Avoids issues with heavily populated, onshore areas.
- Typically one owner for leasing and pipeline siting.
- Reduces difficulty of obtaining surface and mineral owner rights if on Federal lands.
- Reduces risks to USDW.
- Formation fluid in offshore sediments is typically similar to sea water in terms of chemistry and salinity (30,000 to 40,000 ppm total dissolved solids).
- Utilizes existing infrastructure from natural gas and oil facilities and right-of-ways.
- Provides CO_2 storage in areas of many large, stationary CO_2 sources along coastlines and areas that may have potentially limited options for onshore CO_2 storage.

Atlas V Offshore CO_2 Storage Potential

Offshore CO_2 Storage Potential



0 125 250 500 750 1,000 Kilometers

0 75 150 300 450 600 Miles

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Large-Scale Field Projects

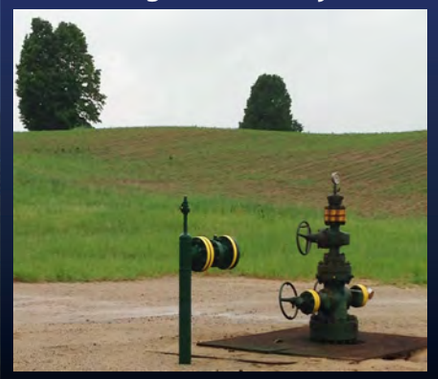
Kevin Dome Project

CO_2 Source: Natural
Storage Type: Saline

Bell Creek Field Project

CO_2 Source: Natural Gas Processing
Storage Type: Enhanced Oil Recovery

Michigan Basin Project



CO_2 Source: Natural Gas Processing
Storage Type: Enhanced Oil Recovery

PCOR Partnership

Toole County, Montana

BIG SKY CARBON SEQUESTRATION PARTNERSHIP

Southeast Montana

MGSC

Ostego County, Michigan

MRCSP MIDWEST REGIONAL CARBON SEQUESTRATION PARTNERSHIP

WEST COAST REGIONAL CARBON SEQUESTRATION PARTNERSHIP westcarb.org

SWP

Decatur, Illinois

Ochiltree County, Texas

SECARB Southeast Regional Carbon Sequestration Partnership

Cranfield, Mississippi

Citronelle, Alabama

Illinois Basin–Decatur Project

CO_2 Source: Ethanol Plant
Storage Type: Saline

Farnsworth Unit Project

CO_2 Source: Ethanol & Fertilizer Production
Storage Type: Enhanced Oil Recovery

Cranfield Project

CO_2 Source: Natural
Storage Type: Saline/Enhanced Oil Recovery

Citronelle Project

CO_2 Source: Coal Power
Storage Type: Saline

Large-Scale Field Projects

Background image: Site of the Bell Creek CO_2-EOR project in the Powder River Basin of southeastern Montana.

PCOR Partnership

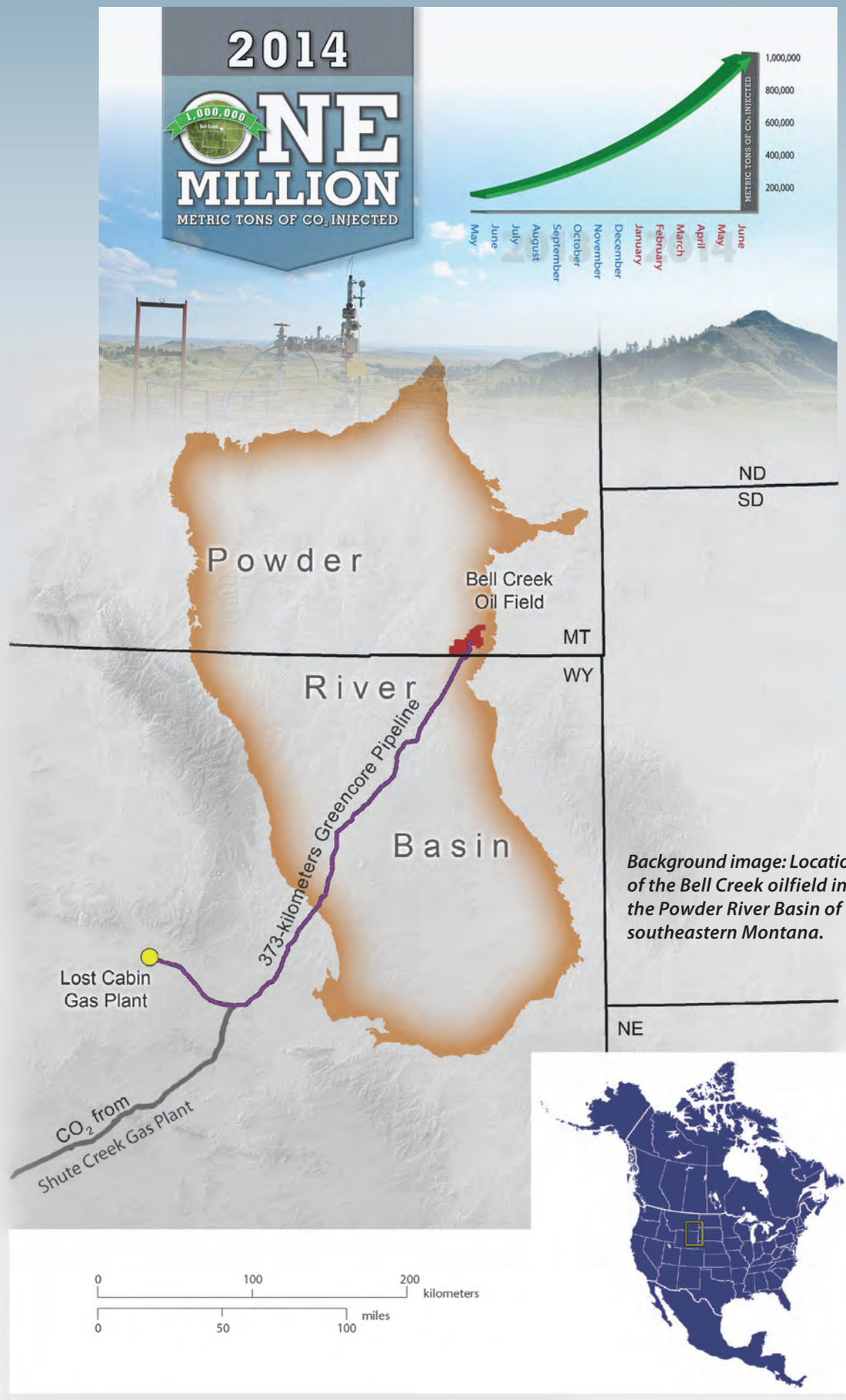
Introduction

The Plains CO_2 Reduction (PCOR) Partnership, led by the Energy & Environmental Research Center (EERC), is working with Denbury Onshore LLC (Denbury) to study carbon dioxide (CO_2) storage associated with a large-scale commercial enhanced oil recovery (EOR) project at the Denbury-operated Bell Creek oilfield. The lessons learned from this study will provide stakeholders with information necessary to move CCS technology development and deployment into broader commercial implementation.

The Lost Cabin and Shute Creek gas-processing facilities in Wyoming provide the CO_2 needed for the project; the CO_2 is transported to the field via the Greencore pipeline with a tie-in from the Anadarko pipeline. The CO_2 is injected into an oil-bearing sandstone reservoir in the Muddy Formation at a depth of approximately 1,370 meters (4,500 feet). This collaborative project is (1) demonstrating that CO_2 storage can be safely and permanently achieved on a commercial scale in association with an EOR operation; (2) demonstrating that oil-bearing sandstone formations are viable regional storage formations for CO_2; and (3) demonstrating that monitoring, verification, accounting (MVA), and assessment methods can be used to effectively monitor CO_2 storage in association with commercial-scale CO_2-EOR projects.

PROJECT HIGHLIGHTS

- Injected more than 1 million metric tons (1.1 million tons) of CO_2 (achieved July 2014) since operations began at the Bell Creek site in May 2013.
- Completed collection of relevant baseline MVA data to aid in evaluating site security, accounting, and location of the lateral and vertical extent of CO_2 in the Bell Creek oilfield.
- Produced a 20-minute video to acquaint a technical audience with the basics of casing-conveyed permanent downhole monitoring systems, as well as the unique field installation practices these systems require.



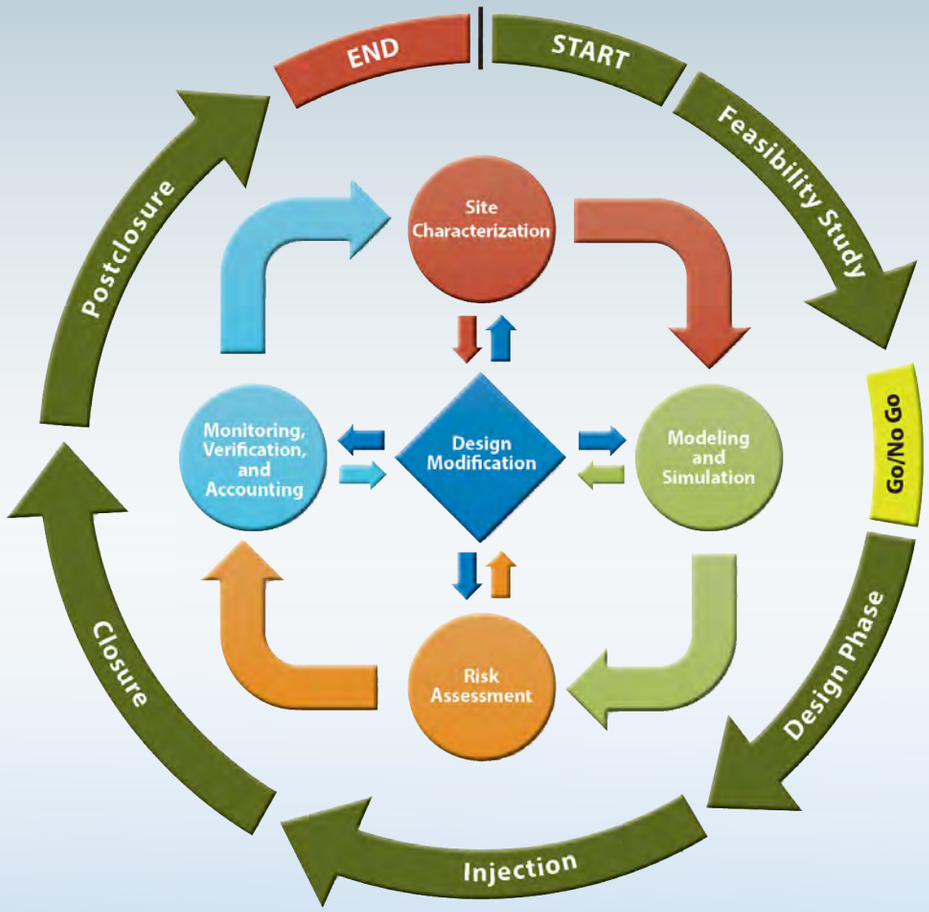
Background image: Location of the Bell Creek oilfield in the Powder River Basin of southeastern Montana.

Site Characterization

A robust and iterative site characterization program was initiated in 2010 to provide data necessary to establish baseline reservoir characteristics and modeling and simulation activities. Characterization activities provide a solid foundation for the other critical elements of the Bell Creek project (risk assessment, modeling and simulation, and MVA), resulting in an increased confidence in predicting and tracking CO_2 movement.

Key site characterization activities include the following:

- Vintage well logs, core analysis, and well file data from more than 700 wells within and surrounding the Bell Creek oilfield were acquired and incorporated into the geologic model.
- A 194-km^2 (75-mi^2) lidar survey collected over the field in July 2011 was used to verify and correct well location and elevation data throughout the field, improving structural interpretations of the reservoir.
- A monitoring and characterization well was drilled in December 2011. A full suite of well logs, 33.5 meters (110 feet) of 10 centimeter (4 inch)-diameter core, and 47 sidewall cores were acquired from the reservoir, along with top and bottom seals.
- Three casing-conveying pressure/temperature gauges and a fiber optic distributed temperature system were installed during completion of the monitoring well to provide reservoir characterization data prior to and during injection.
- A 104-km^2 (40-mi^2), 3-D seismic survey was collected in August 2012 to aid in structural interpretation and to provide a baseline data set for future time-lapse CO_2 monitoring. A repeat 3-D seismic survey was collected in 2014.
- Thirty-three baseline pulsed-neutron well logs were collected in the summer of 2013. Pulsed-neutron well logs provide data sets for determining CO_2, water, and oil saturation changes in the reservoir. Four repeat acquisitions were performed on subsets of the wells, with more planned throughout the project.
- Two 3-D vertical seismic profile (VSP) seismic surveys were conducted in the spring of 2013, which included the installation of a permanent geophone array. These surveys and the geophone array allow for time-lapse data acquisitions for CO_2 monitoring and passive seismic monitoring during injection. Repeat acquisitions occurred in 2014.



The PCOR Partnership's adaptive management strategy incorporates site characterization, modeling and simulation, risk assessment, and MVA in an iterative approach to CCS project management.

Background image: Vibroseis trucks conducting seismic activities in the Bell Creek Field.

Risk Assessment, Simulation, and Modeling

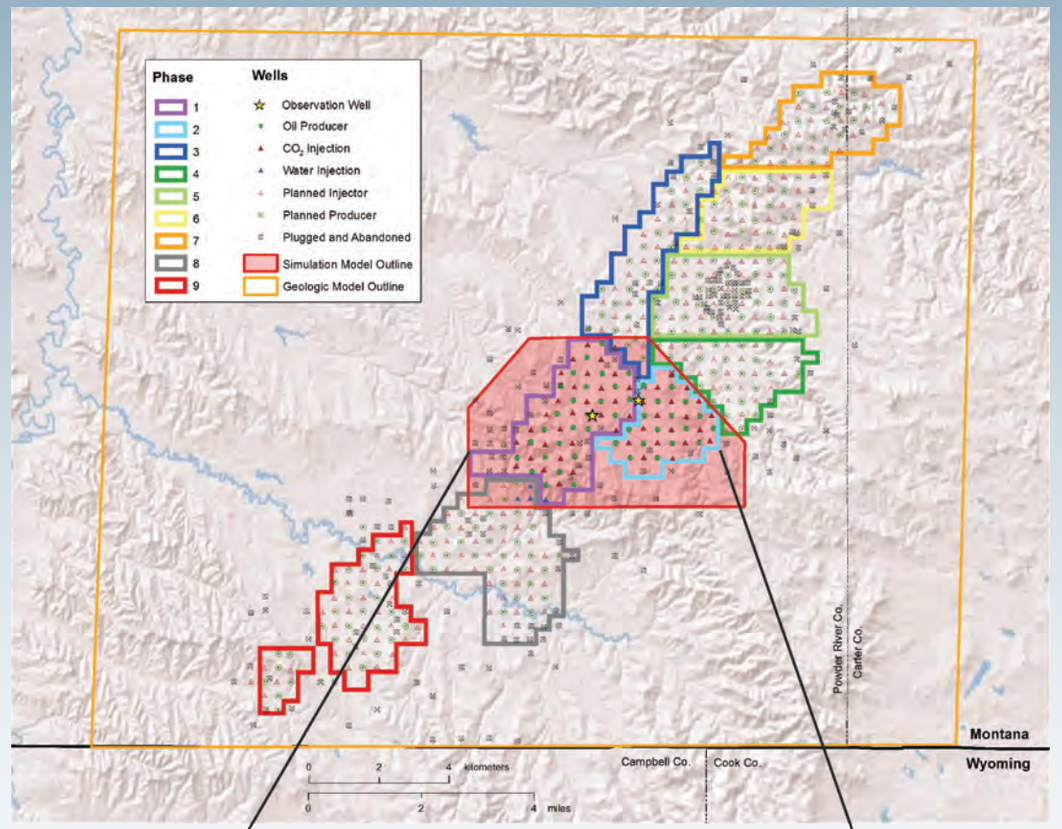
A wide variety of modeling activities have been conducted at the Bell Creek site, including geologic models at multiple scales, predictive multiphase fluid flow simulations, geomechanical modeling, and geochemical simulation. These models and simulations are used to interpret and analyze the geologic, reservoir, and fluid data and to conduct predictive multiphase flow, geomechanical, and geochemical simulations. These efforts identify data gaps and guide the MVA program to better predict and address challenges with long-term associated CO_2 storage.

518-km² (200-mi²) Static Geocellular Model (A 3-D mesh representing upper and lower caprocks and the reservoir): This model was constructed to better understand the injection horizon, the lateral pinch-outs, and overlying and underlying seals.

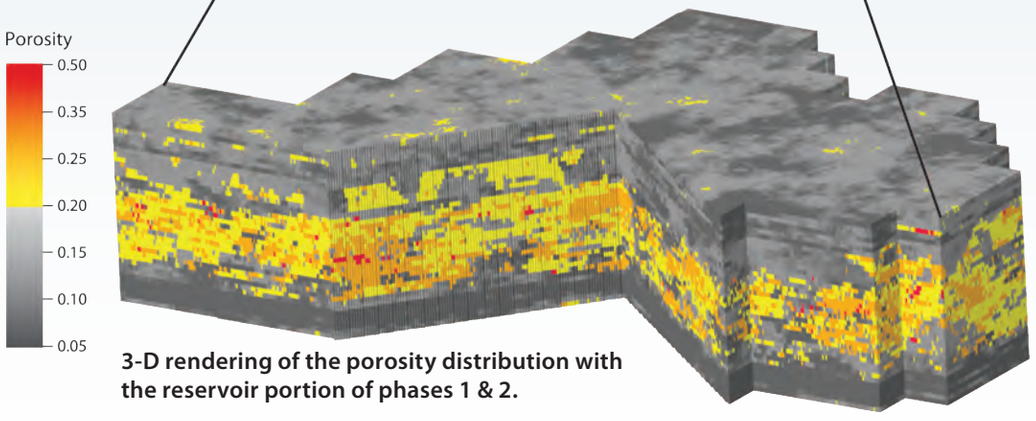
26-km² (10-mi²) Numerical Flow Simulation Model (A 3-D mesh centered on the Phase I and II areas of the Bell Creek Field and spanning the reservoir interval): This model was history-matched to validate the geocellular model and then used to run predictive simulations to evaluate reservoir performance, CO_2 sweep and storage efficiencies, CO_2 breakthrough time at various production wells, pressure response, and long-term CO_2 plume migration. Subsequent efforts have added Phase II to the numerical flow model.

518-km² (200-mi²) 3-D Mechanical Earth Model (MEM) (Centered on the Bell Creek Field and incorporating each formation from the lower seal to the surface): This model was constructed to predict geomechanical changes to the reservoir and surrounding formations as a result of injection and production activities and to assess the local and regional stress regime.

Risk management, modeling, and MVA are interrelated processes, where the results of one become the inputs of the others. This creates an iterative process to manage the risks throughout the life of the project. In the initial risk assessment, the EERC project team identified and evaluated 120 potential subsurface technical risks associated with the study of long-term CO_2 storage that were grouped into broad categories (e.g., capacity, injectivity, and retention; lateral migration; vertical migration). It was determined that the technical risks identified were adequately addressed by the current MVA program. Most risks are monitored using more than one measurement, providing redundant lines of evidence for inferring migration of CO_2 or other fluids beyond the reservoir. Additionally, 24 strategic risks were identified and assessed (e.g., CO_2 supply, management, or policy changes). None of these risks demonstrated significant potential to impact the project.



Map showing simulation and geologic modeling extents in relation to the Bell Creek oilfield.



3-D rendering of the porosity distribution with the reservoir portion of phases 1 & 2.

The PCOR Partnership's management approach allows the changing risk profile to be tracked.

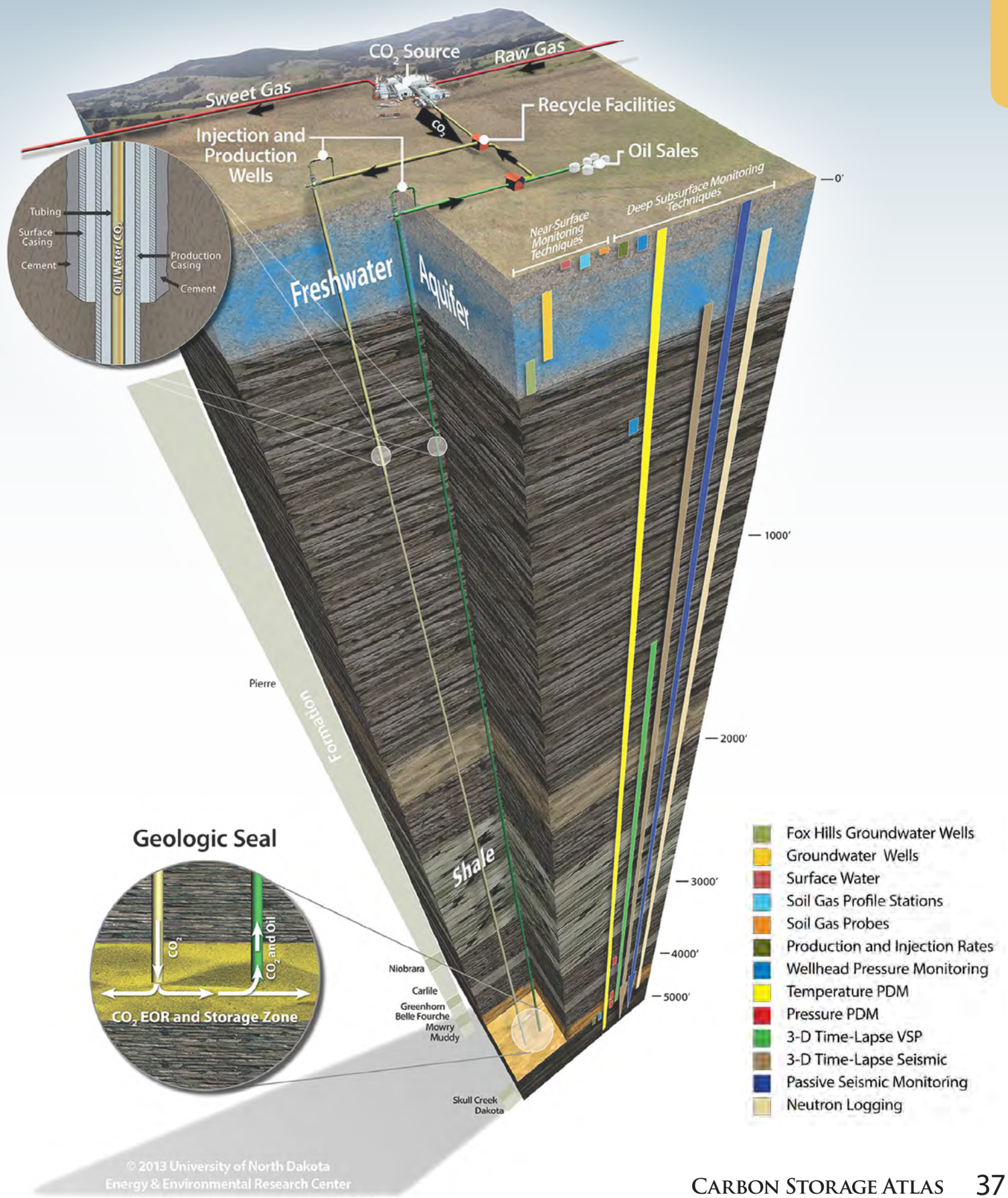
Monitoring, Verification, Accounting, and Assessment

The goal of the MVA program is to provide critical data to verify site security, evaluate reservoir behavior during injection, determine the fate of injected CO_2, and investigate mechanisms that affect CO_2 storage efficiency within the EOR process, all while operating in a manner compatible with the commercial CO_2-EOR operation. The MVA program uses time-lapse data acquisitions as part of a surface-, shallow-subsurface-, and deep-subsurface-monitoring effort guided by the PCOR Partnership's adaptive management approach.

The deep subsurface MVA program focuses on the storage reservoir interval as well as monitoring the entire interval from the reservoir, up to the deepest underground source of drinking water (USDW). The deep subsurface MVA program uses a combination of wellbore and geophysical technologies to track the vertical and lateral extent of fluid and CO_2 during and after injection.

A near-surface-monitoring program accounts for monitoring the interval between the deepest USDW and the surface, including surface water bodies. This program (1) established baseline conditions for soil gas and water chemistries present in surface water, soil, and shallow groundwater formations in the vicinity of the CO_2 injection site, and (2) provides data to demonstrate that surface environments remain unaffected by fluid or gas migration and/or to identify the source and quantify the impact of an out-of-zone migration event should it occur.

No single technology exists that is capable of effectively monitoring the lateral and vertical extent of CO_2 throughout the stratigraphic column in both the near-wellbore and interwellbore environment for all storage sites. For this reason, the PCOR Partnership has designed a program specific to the needs of the Bell Creek oilfield that monitors a variety of physical phenomena using several commercially available technologies. The specific technologies selected are also designed to operate in a complementary manner, where an anomalous detection from one monitoring technique can be investigated using one or more of the remaining techniques to confirm whether an issue exists. Additionally, the PCOR Partnership is evaluating each of these monitoring technologies to understand their benefits, limitations, and challenges when deployed in conjunction with a commercial CO_2-EOR operation.

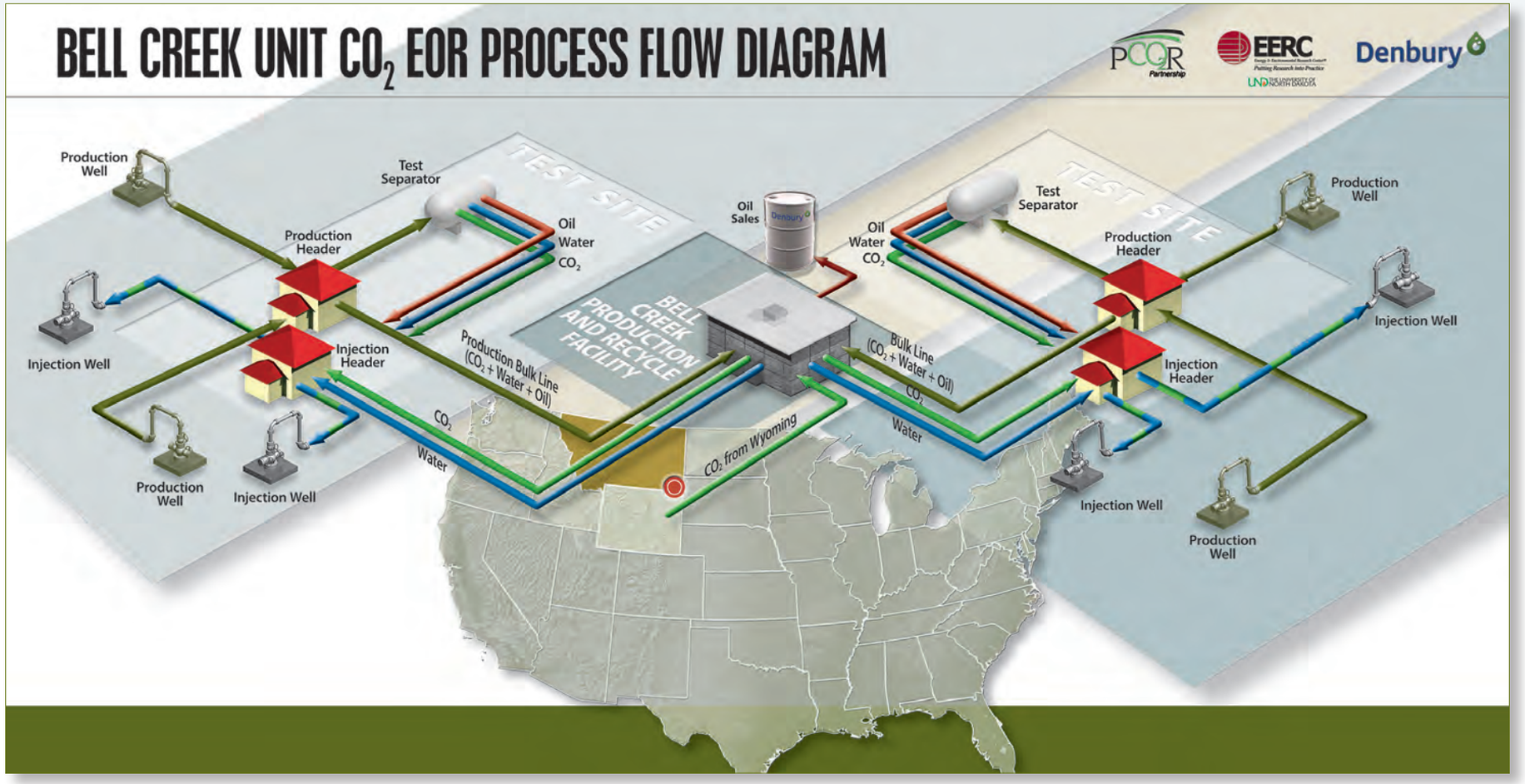


Site Operations

The Bell Creek project began CO_2 injection in May 2013. The CO_2 is delivered to the site via pipeline from the Lost Cabin and Shute Creek gas plants in Wyoming, where it is separated from the process stream during natural gas refinement. The supplied CO_2 is delivered at a target rate of more than 1.4 million cubic meters per day (50 million cubic feet per day) to the Bell Creek oilfield. The CO_2 is injected into the oil-bearing sandstone reservoir of the Lower Cretaceous Muddy (Newcastle) Formation at a depth of approximately 1,370 meters (4,500 feet). The CO_2 injection is occurring in a staged approach (nine planned CO_2 developmental phases) across the field. The reservoir is suitable for miscible flooding conditions and is likely to meet the incremental oil production target of 40 to 50 million barrels.

Injection/production will occur via a typical 5-spot pattern of 40-acre spacing. Currently, the field is operated under continuous CO_2 injection in the Phase I development area. As with typical EOR procedures, recovered oil, CO_2, and water will be separated at the process/recycle facilities located onsite. Oil is sold, whereas the water and CO_2 are recycled and reinjected as part of the EOR operation.

Bell Creek production and recycle facility.



PCOR Partnership Activities

In addition to the Bell Creek Field Project, the PCOR Partnership has several other ongoing activities that provide important data in support of the U.S. Department of Energy's (DOE) efforts toward commercializing geologic CO_2 storage.

Fort Nelson Demonstration Project (CO_2 storage in a saline formation, Fort Nelson, British Columbia): A best practices manual (BPM) has been completed documenting the work of the multiyear Fort Nelson Feasibility Project. The BPM demonstrates the successful implementation of an adaptive project management strategy that included several rounds of site characterization, dynamic modeling and simulations, two rounds of risk assessment, and MVA strategy development. The manual details the effectiveness of this approach for the commercial implementation of geologic CO_2 storage in a saline formation.

Aquistore Project: This project, led by the Petroleum Technology Research Centre, is located near Estevan, Saskatchewan, Canada. The PCOR Partnership is involved with geologic characterization, geocellular modeling, and predictive simulation, and is also represented on the Science and Engineering Research Committee (SERC) project board. This carbon capture and storage (CCS) project is significant because it encompasses the entire CCS process train, with CO_2 captured from a power plant and transported by pipeline to a saline storage site.

Regional Characterization: The PCOR Partnership continues to evaluate the CO_2 storage resource potential within its region. The PCOR Partnership recently collaborated with a number of State, Provincial, and international groups to evaluate the storage resource potential of a 1.1-million-km^2 (400,000-mi^2) basal saline formation system. Additionally, regional characterization efforts include working with DOE to refine the methodology used to calculate CO_2 storage resource values in saline reservoirs, oilfields, and organic-rich shales.

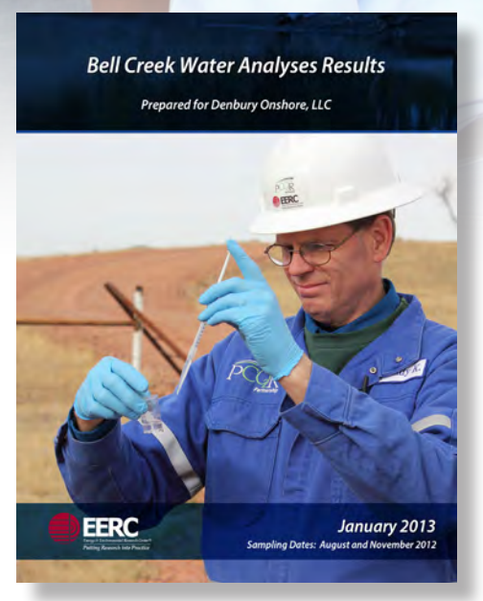
Public Outreach: The PCOR Partnership continues to produce numerous outreach products, such as a regional atlas, fact sheets, CCS documentaries and video clips, public presentations, and educational and training programs. The PCOR Partnership also has an extensive network of industry and regulatory partners, which meet annually for a regulatory review with the region's State and Provincial regulators.

PCOR Partnership Public Outreach

The PCOR Partnership covers all or part of 9 States and 4 Canadian Provinces with a total population of approximately 30 million people in 9 million households. Outreach and education focus on activities and developing products intended to raise awareness about safe, economical, and long-term CO_2 storage to three types of audiences: the general public across the region, key audiences at the regional level, and targeted audiences in the vicinity of the large-scale CO_2 storage projects.

Outreach products and activities that promote awareness of the Bell Creek project include the following:

- Public website
- PCOR Partnership Regional Atlas (distributed 1,600 copies of the 4th edition)
- DVDs documenting the installation of a permanent downhole monitoring system
- Periodic soil and water quality monitoring reports to specific landowners
- Project fact sheet
- Outreach poster summarizing the project
- Commemorative coin
- 35 technical presentations in the past year
- Four technical posters



Scan this code to learn more about the PCOR Partnership Program

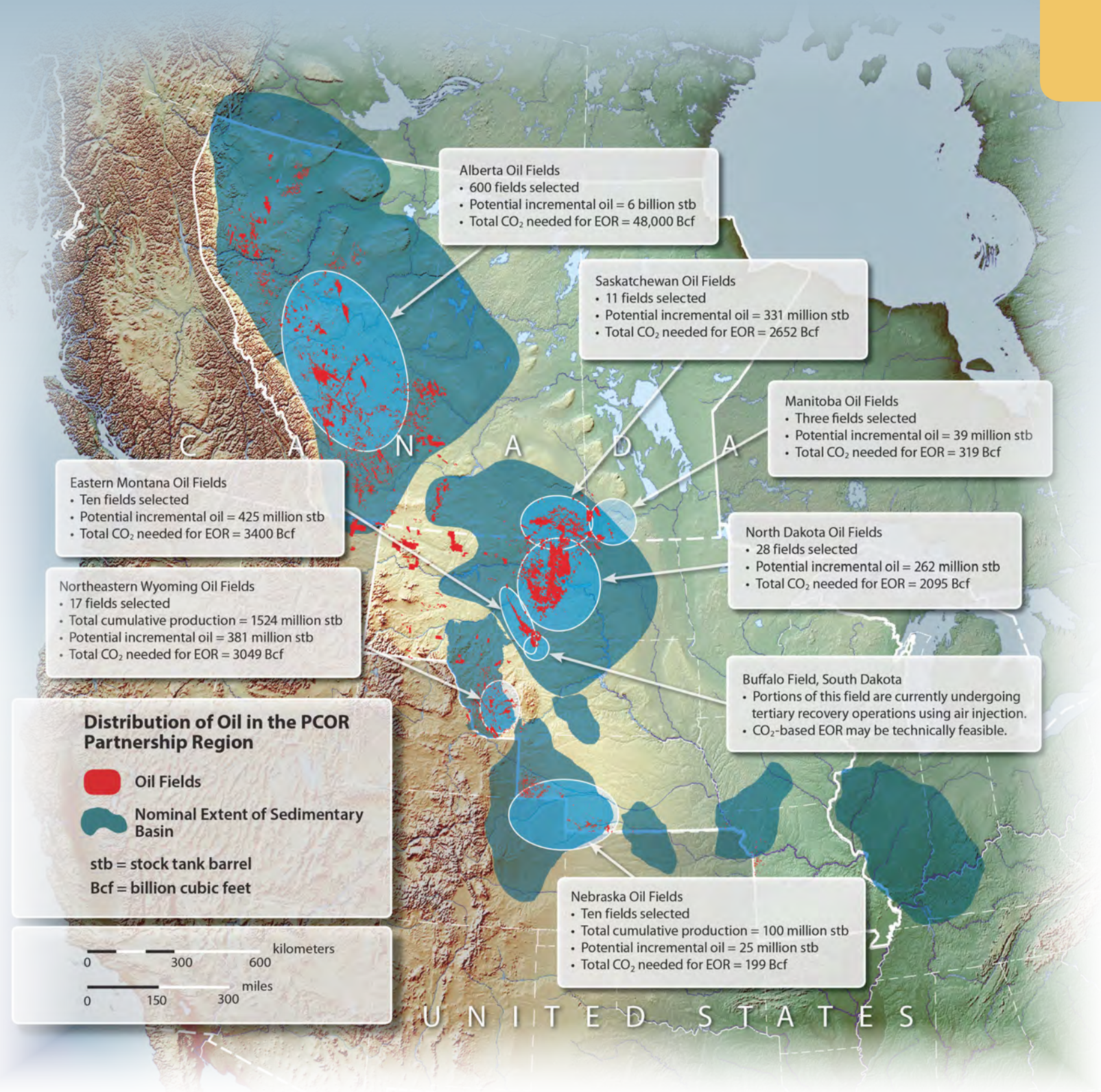
For more information about the PCOR Partnership, please visit: http://www.undeerc.org/pcor/

Commercialization of CCS in the PCOR Partnership Region

Oilfields offer an opportunity to implement large-scale CO_2 storage because (1) they are well characterized, (2) an established industry is already in place with a legal framework for ensuring safe operation and an extensive operating history, and (3) the sale of the incremental oil will considerably offset the cost of CO_2 capture and transportation. Ten of the 13 State/Provincial jurisdictions in the PCOR Partnership region have oilfields within their boundaries, and regional characterization activities conducted by the PCOR Partnership show that hundreds of oilfields in the region may be suitable for CO_2-EOR operations.

The volume of incremental oil that could be produced using CO_2-EOR from the oilfields evaluated by the PCOR Partnership has been estimated at approximately 7 billion barrels. Assuming a crude oil price of $90/bbl, the value of the incremental oil totals approximately $630 billion. Economics will drive the commercial implementation of CO_2-EOR, which could then serve as a bridge for geologic CO_2 storage in saline formations. The demonstration of geologic CO_2 storage would show regulators and the public that subsurface CO_2 injection can be done in a safe, effective manner.

The magnitude of this financial opportunity for the development of a CO_2 market has attracted the attention of oilfield operators and the owners of large stationary CO_2 sources in the PCOR Partnership region, including coal-fired power plants. Many of these companies are members of the PCOR Partnership and have expressed support for an EOR-focused project. This support represents another positive economic driver for CO_2-EOR, increasing the likelihood that the storage strategy could move forward at a commercial scale, with or without changes in the climate policy of the United States. In addition, demonstrating the technical and economic viability of implementing effective MVA strategies at a large-scale, commercial CO_2-EOR project, such as the Bell Creek project, will provide confidence to many third-party stakeholders, including policy makers, regulators, financiers, and the public, that the implementation of subsurface strategies for CO_2 storage can be monitored and controlled.



CITRONELLE PROJECT

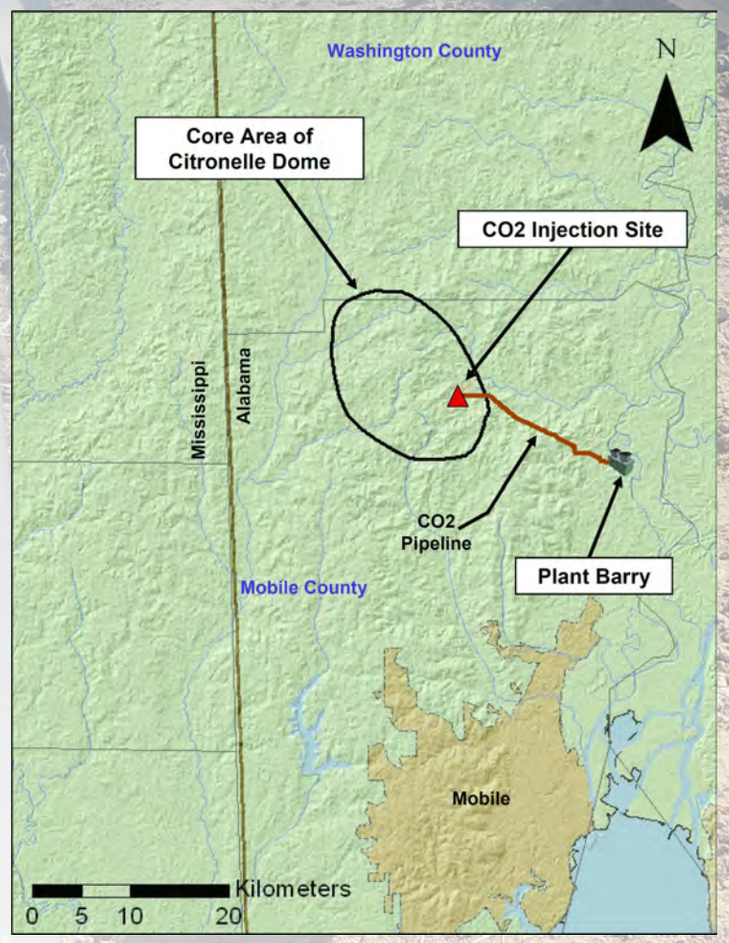
SECARB
Southeast Regional Carbon Sequestration Partnership

Introduction

The Southeast Regional Carbon Sequestration Partnership (SECARB) Citronelle Project has a goal of safely demonstrating large-scale, long-term carbon dioxide (CO_2) injection and storage in a saline reservoir that holds significant promise for future development. This project is the largest demonstration of a fully integrated, pulverized coal-fired carbon capture and storage (CCS) project in the United States as of September 2014, and supports a commercial prototype of CO_2 capture; transportation; subsurface storage; and monitoring, verification, and accounting (MVA), and assessment.

The project begins at the James M. Barry Electric Generating Plant in Bucks, Alabama. A demonstration-scale, post-combustion CO_2 capture facility provides CO_2 for the project. A small amount of flue gas is diverted from the plant's #5 coal burning unit and captured using Mitsubishi Heavy Industries (MHI) KM-CDR™ advanced amine technology to produce CO_2. The captured CO_2 is compressed at Plant Barry and transported by pipeline to the injection location southeast of Citronelle, Alabama.

The CO_2 is injected into the Lower Cretaceous-age Paluxy Formation, a saline formation that occurs at a depth of approximately 3,000 meters (9,400 feet) and overlies the oil production horizon of the Citronelle oilfield operated by Denbury Onshore, LLC. Carbon dioxide injection began in August 2012. The Citronelle MVA team, led by the Electric Power Research Institute (EPRI) and coordinated by Advanced Resources International, Inc., (ARI) is applying proven and experimental MVA technologies to monitor CO_2 movement in the subsurface during and post-injection. As of September 2014, more than 114,000 metric tons have been injected and safely stored at the site.



Map identifying the location of the CO_2 capture facility at Plant Barry, the pipeline route, and the Citronelle domal structure at the oilfield. Map courtesy of ARI.

CITRONELLE PROJECT HIGHLIGHTS

- As a first-of-its-kind demonstration, this field project is important for understanding the challenges of CCS.
- Risk management and environmental protection are central concerns in any CCS project to ensure human health and safety. To support this integrated project, a framework of legal agreements exists between three entities to ensure that responsibilities and expectations are clearly defined. The Citronelle Project team has developed a site-specific registry of communication and project-related risks.
- The Citronelle Project team, in collaboration with Lawrence Berkeley National Laboratory (LBNL) and the Carbon Capture Project, is developing a unique and innovative monitoring technology, the Modular Borehole Monitoring (MBM) Tool. The MBM Tool is a compendium of MVA protocols designed to be deployed in a "flat pack" cable. This singular flat pack replaces seven different lines, thereby reducing the operational aspects of deploying and operating this MVA prototype tool.
- The project achieved a milestone of more than 100,000 metric tons of CO_2 injected in October 2013.
- The Citronelle Project was recognized by the Carbon Sequestration Leadership Forum (CSLF) in November 2013.

Background image: The dedicated CO_2 pipeline extends 12 miles from Plant Barry to the Citronelle oilfield. Photo courtesy of Denbury Resources, Inc.

Site Characterization

The Citronelle Project's geologic storage and MVA sites are located on the flanks of the Citronelle Dome, approximately 5 kilometers (3 miles) southeast of the city of Citronelle, Alabama. The team selected the Paluxy Formation (saline) as the target CO_2 injection zone, because it holds significant promise for future CCS project development. The Citronelle Dome was selected for its close proximity to Plant Barry and its ideal geology for the safe and long-term containment of CO_2.

When evaluating potential project sites, the SECARB team initiated a comprehensive investigation of the regional geology to include regional physiography, regional structural geology, subsurface stratigraphy, CO_2 storage area subsurface characterization, geochemistry, hydrology, natural and induced seismicity, and mineral resources. The team concluded that the porous and permeable sands of the proposed injection zone, the Paluxy Formation, present a favorable injection reservoir in terms of areal extent and petrophysical characteristics. The confining zone, the basal shale of the overlying Washita-Fredericksburg Formation, is persistent throughout the Citronelle area and possesses the appropriate criteria to act as an effective CO_2 seal. In addition to the basal Washita-Fredericksburg Shale, there are secondary overlying confining units including the Middle (Marine) Tuscaloosa Formation, the Selma Group, and the Midway Shale, which create a robust confining system. These formations occur stratigraphically between the injection zone and the base of the lowermost underground source of drinking water (USDW).

Since the project is located in an active oilfield, the SECARB team examined the potential risk of CO_2 migration along existing wellbores in the area as part of its site characterization activities. The team cataloged data and well completion records for wells within the modeled plume area, or Area of Review (AoR). In addition, Denbury Onshore, LLC, maintains an active mechanical integrity test (MIT) program for the oilfield and cement bond logs were run on selected wells in the AoR. Adequate cement bonds were observed across the injection interval and confining units. Currently, the team performs active well maintenance, testing, and monitoring to mitigate any well integrity issues.

Core taken from the characterization well in January 2011 and used for site characterization.

Background image: Drilling rig at the characterization well, January 2011.

Risk Assessment, Simulation, and Modeling

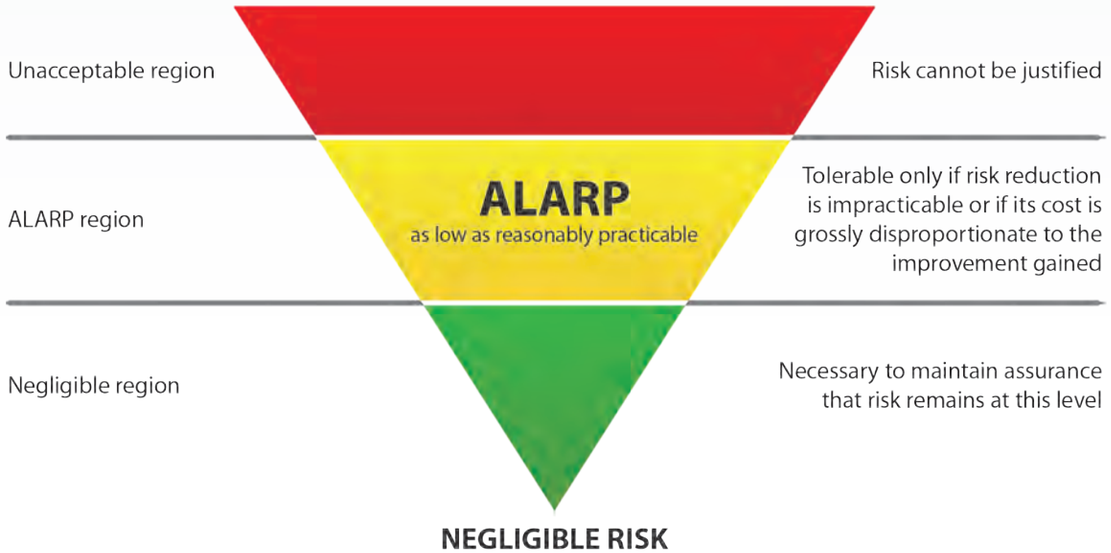
Operational risks for a CCS project must be identified, assessed for consequence and likelihood, documented early, and revisited often to safeguard human health and the environment. The CO_2 capture unit supplying the CO_2 for the Citronelle Project is owned and operated by Alabama Power, a subsidiary of Southern Company. Denbury Onshore, LLC, constructed the pipeline and operates the CO_2 injection well. The SECARB team operates the MVA program. A framework of legal agreements exists between the multiple entities to ensure that responsibilities and expectations are clearly defined. The project team worked cooperatively with DNV GL (formerly Det Norske Veritas and DNV Kema) to develop a site-specific registry of communication and project-related risks. Risk workshops were conducted prior to initiating field activities, prior to the start of CO_2 injection, and at the beginning of the post-injection monitoring period.

Risks associated with the Citronelle Project fall within five primary categories: health and safety, environmental protection, cost, reputation, and schedule to start up integrated operations. These risks are assessed as slight, minor, moderate, severe, or persistent severe. The goal is to have risk treatment actions in place to reduce the severity to as low as reasonably possible. No risks have been assessed as unacceptable, and the highest risks are related to regulatory uncertainty and successful integration of project components.

Reservoir simulation for the Citronelle Project was conducted using detailed geologic models constructed as part of the site characterization effort. The project team employed assumptions of trapping mechanisms from SECARB's Validation Phase field project site in Mississippi. A simulation of CO_2 injection occurring over 3 years was conducted to understand the movement of the plume under injection operations and under equilibrium flow conditions. The goal of this ongoing simulation effort is to determine the movement and fate of the CO_2 within the Paluxy Formation and serve to delineate the project's AoR within which the condition of all existing well penetrations was assessed. From the injection simulations, the model shows that the predicted plume extent is within the permitted AoR limit of approximately 520 meters (1,700 feet).

The *GEM-GHG* reservoir flow simulator was employed to model subsurface CO_2 injection into the injection zone. *GEM-GHG* is a robust, equation-of-state, fully compositional reservoir simulator for modeling the flow of three-phase, multi-component fluids. The simulator includes the capability of modeling CO_2 (and other gases) injection in parallel with comprehensive CO_2 trapping, including residual gas trapping via relative permeability hysteresis, CO_2 dissolution in the aqueous phase and intra-aqueous reactions, mineral dissolution, and precipitation.

		CONSEQUENCE				LIKELIHOOD				
						A: Remote	B: Unlikely	C: Possible	D: Probable	E: Certain
		Health and Safety (HS) and Environmental Protection (E)	Cost	Reputation	Schedule to Start-Up of Operations	Very Unlikely (P<0.05) to occur during life of project	Unlikely to occur during life of project	50/50 chance of occurring during life of project	Likely to occur during life of project	Very Likely (P>0.95) to occur during life of project
CONSEQUENCE SEVERITY	E: Persistent Severe	HS: On-site and off-site exposures/injuries E: Persistent severe damage. Extensive remediation required. Environment restored > 5 years.	More than $10 million	National or International media attention. Regulators shut down operations.	More than 12 months	M	M	H	H	H
	D: Severe	HS: On-site exposures/injuries leading to absence from work more than 5 days or long term negative health effects. E: Severe environmental damage. Remediation measures required. Environment restored < 5 years.	$1 to $10 million	Regional media attention. Regulatory or legal action taken.	6–12 months	L	M	M	H	H
	C: Moderate	HS: Lost time event/on-site injury leading to absence from work up to 5 days, or affecting daily life activities more than 5 days. E: Damage managed by Company response teams. Environment restored < 2 years.	$100,000 to $1 million	Local media attention. Regulatory or legal action likely.	3–6 months	L	L	M	M	H
	B: Minor	HS: Minor injury or health effect - affecting work performance, such as restricting work activities, or affecting daily life activities for up to 5 days. E: Damage, but no lasting effect.	$10,000 to $100,000	Public awareness may exist, but there is no public concern.	1–3 months	L	L	L	M	M
	A: Slight	HS: Slight injury or health effect - not affecting work performance or daily life activities. E: Damage contained within premises.	Less than $10,000	On-site communications.	Less than 1 month	L	L	L	L	M



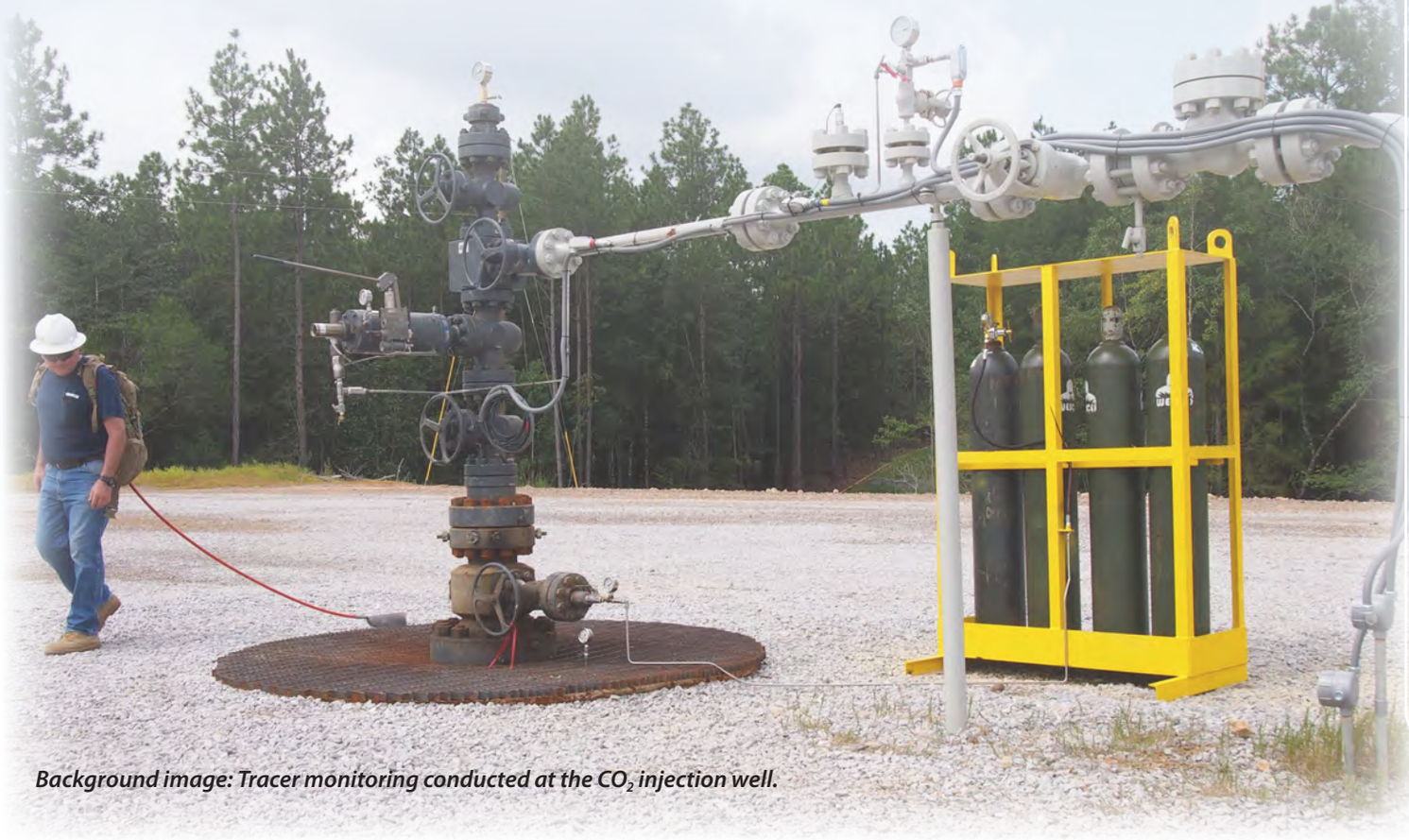
The Project Risk Assessment Matrix (HS – health and safety, E – environment, L – low risk, M – medium risk, H – high risk). Colors are indicative of risk level. Risk scenarios in the green band are considered acceptable, those in the red band are currently unacceptable and must be reduced, and risks in the yellow band are of concern but may be tolerable without further risk reduction. Source: DNV-GL, 2012.

Monitoring, Verification, Accounting, and Assessment

The Citronelle Project's MVA strategy is designed to utilize existing oilfield subsurface measurement and diagnostic technologies and promising experimental (non-commercial) technologies. The MVA program was created based on the specifics of the site, the subsurface geology, and the ongoing oilfield operations in order to maximize the opportunity to collect high-quality data. Throughout the stages of the project, the deployed technologies will be evaluated to document their performance and determine their robustness and future application to monitor CO_2 flow and containment.

The SECARB team considered a variety of existing MVA tools for the Citronelle Project, primarily based on results from other CCS projects, the team's expertise using monitoring technologies in oilfield environments, and recommendations and requirements from the State regulatory agency. Ten existing MVA tools are deployed at the Citronelle Project. These include CO_2 composition, CO_2 volume, tracers introduced in the CO_2 stream, bottom-hole pressure, pulsed neutron logs (CO_2 saturation), time-lapse crosswell seismic imaging and vertical seismic profiling (wellbore deployed), injection temperature and spinner logs, above-zone pressure and fluid monitoring, soil gas flux, and drinking water aquifer monitoring.

Several experimental technologies are deployed at the site. These include distributed temperature sensing, comparative fluid sampling methods of reservoir fluids, distributed acoustic sensing, and off-set deployment of experimental vertical seismic profiling.



Background image: Tracer monitoring conducted at the CO_2 injection well.

The Modular Borehole Monitoring (MBM) tool is a technology developed as a collaborative effort between SECARB, LBNL, and the Carbon Capture Project. This monitoring tool is a compendium of MVA protocols designed to be deployed in a "flat pack" cable. This singular flat pack replaces seven different lines, thereby reducing the operational aspects of deploying and operating this MVA prototype tool. Within the flat pack, downhole fluid sampling, real-time pressure and temperature monitoring, heating and distributed temperature sensing, distributed acoustic sensing, and hydraulic lines (for separately run seismic geophones) are included. This tool has been positioned in a dedicated monitoring well approximately 800 feet away from the injection well.

The MBM tool has proven useful in collecting continuous, real-time bottomhole pressure and temperature data from the monitoring well. The tool has also provided time-lapse vertical seismic profiles, bottomhole fluid sampling, and heat pulse decay results. The distributed acoustic sensing cables deployed within the MBM sampling array have seismic applications. The fiber optic acoustic cable provides a seismic sampling point nearly every meter along more than 3,000 meters of wellbore, reducing the cost of deploying seismic applications. The initial results are promising and may prove valuable to MVA protocols.

Modular Borehole Module flat-pack. Image courtesy of LBNL.

Site Operations

The integrated Citronelle Project begins at Alabama Power's (a subsidiary of Southern Company) existing 2,657-megawatt (MW) James M. Barry Electric Generating Plant in Bucks, Alabama. A separately funded, demonstration-scale, post-combustion CO_2 capture facility provides CO_2 for the project. A small amount of flue gas (equivalent to the amount produced when generating 25 MW of electricity) is diverted from the plant's #5 coal burning unit and captured using Mitsubishi Heavy Industries (MHI) KM-CDR™ advanced amine technology to produce high purity (greater than 99 percent) CO_2. The captured CO_2 is dehydrated and compressed at Plant Barry to approximately 1,500 pounds per square inch (psi). The CO_2 is transferred to Denbury Onshore, LLC, at the Plant Barry property line and transported for approximately 19 kilometers (12 miles) via a four-inch dedicated pipeline to the injection location southeast of Citronelle, Alabama.

Three new wells were drilled as part of the Citronelle Project: (1) a reservoir characterization/monitoring well, (2) a characterization/observation/backup injection well, and (3) a dedicated CO_2 injection well. In addition to these new wells, the project utilizes several existing oilfield wells surrounding the CO_2 injection site to monitor injection operations and ensure public safety. The reservoir characterization/monitoring well was completed in January 2011. Class V (Experimental Technologies) Underground Injection Control (UIC) permits for the remaining two wells were secured in November 2011. These wells were consecutively drilled to modern specifications with cement to surface and many other Class VI standards applied. The wells were completed in February 2012. The Citronelle Project team operated within the parameters established by the two Class V UIC permits: (1) a maximum average injection rate of 9.6 million cubic feet per day, (2) a maximum volume of 182,500 metric tons of CO_2 per year, and (3) a maximum wellhead injection pressure of 3,300 psia.

Carbon dioxide arrives at the injection site at approximately 1,350 psi. A horizontal CO_2 booster pump was designed and fabricated at the dedicated injection well site and is used as needed to increase the pressure of CO_2 flowing to the injection well. The booster pump includes 130 stages, a 300-horsepower electric motor, two pneumatic shut downs, two pneumatic control valves, two manual shut down valves, one discharge check valve, satellite link for communication, and a standalone air compressor system to operate the valves and controls.

The project was designed to inject up to 150,000 metric tons per year of CO_2 captured from the pilot facility at Plant Barry for a period of up to 3 years. Carbon dioxide injection operations began on August 20, 2012, and ended in September 2014. In October 2013, the project achieved a milestone of more than 100,000 metric tons of CO_2 injected. The project is in its post-injection monitoring phase. More than 114,000 metric tons of CO_2 were injected and safely stored at the site.

During the injection period, multiple commercial and experimental CO_2 monitoring technologies have been deployed to track the CO_2 plume, measure the pressure front, understand CO_2 trapping mechanisms of the Paluxy Formation, and monitor for release. Three years of post-injection monitoring are planned and the wells will either be plugged and abandoned per State regulations or re-permitted for CO_2-enhanced oil recovery (EOR) operations into a deeper formation.

CO_2 capture facility at Plant Barry. Photo courtesy of Southern Company.

CO_2 injection well at Denbury's Citronelle oilfield.

Underground Injection Control Permitting

Regulatory uncertainty was identified as one of the Citronelle Project risks. Therefore, the team began preparing the UIC permit application and communicating with the State regulatory authority, the Alabama Department of Environmental Management (ADEM), as soon as the project plan was agreed upon by the project partners. The UIC Class V (Experimental Technologies) permit application for the dedicated and backup CO_2 injection wells was initially submitted in December 2010. During the same month, the U.S. Environmental Protection Agency (EPA) issued the Class VI UIC permit rules for CO_2 injection for geologic storage and became involved with ADEM in establishing the terms of the permit. The UIC permit application was updated and resubmitted in March 2011 and ADEM issued the Class V permit in November 2011.

The Class V permit contained several Class VI reporting requirements, including:

- Injection AoR determined by annual modeling
- Periodic AoR updates based on monitoring and modeling results
- Extensive deep, shallow, and surface CO_2 monitoring
- Monthly reporting of injection pressures, annular pressures, and injection stream composition
- Injection stream monitoring
- Periodically updated Corrective Action Plan
- Site closure based on USDW non-endangerment demonstration (5-year renewal)
- Pressurized annulus throughout injection (+/- 200 psig)
- Emergency and remedial response plan
- Post-injection site care plan

Two CO_2 injection wells were drilled and completed from December 2011 to January 2012. Authorization to inject was requested in April 2012 and approved by ADEM in August 2012. The integrated CO_2 capture, transportation, injection, storage, and monitoring project became fully operational on August 20, 2012. The UIC permitting and CO_2 injection authorization process spanned a collective 20 months.

Gopher Tortoise.

Background image: Archeological and cultural surveys were conducted at the Citronelle Project site.

ENVIRONMENTAL AND CULTURAL RESOURCES ASSESSMENTS

As part of the National Environmental Protection Act (NEPA), the Citronelle Project was evaluated for significant environmental impacts. The project received a Categorical Exclusion (CX) for all locations performing office work, planning, and coordination. An Environmental Assessment (EA) document was prepared for the project, including supplements for the pipeline and transmission line. A Finding of No Significant Impact was issued by the National Energy Technology Laboratory (NETL) in March 2011.

During the EA process, it was determined that the project site was near a previously identified archeological site not eligible under the National Register of Historic Places. The Alabama Historical Commission's State Historical Preservation Office (SHPO) conducted two cultural resources assessments, and no cultural resources were discovered, warranting no further investigation.

A U.S. Army Corps of Engineers (USACE) permit authorization was required for the Citronelle Project, because it involved the temporary placement of materials into U.S. waters. Of the 19-kilometer (12-mile) route, the team directional drilled 18 sections of the pipeline, 9 to 18 meters (30 to 60 feet) deep, under wetlands, roads, utilities, railroad tracks, and tortoise colonies. Surface re-vegetation and erosion control activities were required after drilling was completed.

Gopher tortoises are present at the site and their habitat is protected in Alabama. More than 100 active and inactive gopher tortoise burrows were located near the project area. In cooperation with officials at the U.S. Fish and Wildlife Service, the Citronelle Project team avoided disturbance of these burrows by directionally drilling the pipeline and marking burrows and burrow areas at the well pad site.

Public Outreach, Knowledge Sharing/Dissemination

The Citronelle Project has an active public outreach program that falls under SECARB's formal communications plan. Conducting effective public outreach involves listening, sharing information, addressing concerns, and communicating project risks early and often. The Southern States Energy Board leads the international, national, and regional effort and the individual field teams lead site-specific public outreach activities.

The Citronelle Project team announced the location and details of the CCS demonstration project in May 2009 during an onsite meeting at Plant Barry in Bucks, Alabama. Meetings were also conducted with the Mobile Alabama Press Register's environmental department. In July 2011, the team hosted a community leaders briefing and shared project details, posters, and handouts with the participants. The Mayor of Citronelle hosted a public open house at City Hall in January 2012. During the event, key members of the team provided details related to the project and answered questions from the participants.

The project team has hosted numerous site visits involving hundreds of participants, including tours of the CO_2 capture facility, pipeline infrastructure, and CO_2 injection and monitoring sites. State and local civic leaders and groups, U.S. and international scientists and engineers, students, regulators, and First Nation tribal leaders interested in CCS have toured the site. Alabama Power Company and Denbury Onshore monitor capture, transport, and injection operating conditions at all times and have active communication programs in place for their respective facilities that are used to notify local authorities and the public.

Team members have shared details of the Citronelle Project with various audiences through numerous international knowledge sharing events, presentations, and poster sessions at conferences and workshops. The SECARB website offers current fact sheets, photos of field activities, news, and upcoming and recent events. Project activities and lessons learned are communicated through multiple electronic sources, including an annual briefing to SECARB stakeholders, email notifications, and social networking.

U.S. and Norwegian officials tour Citronelle Project, April 2014.

Scientists from the Industrial Technology Research Institute (Taiwan) visit the CO_2 capture facility, August 2014.

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Commercialization of CCS in the SECARB Region

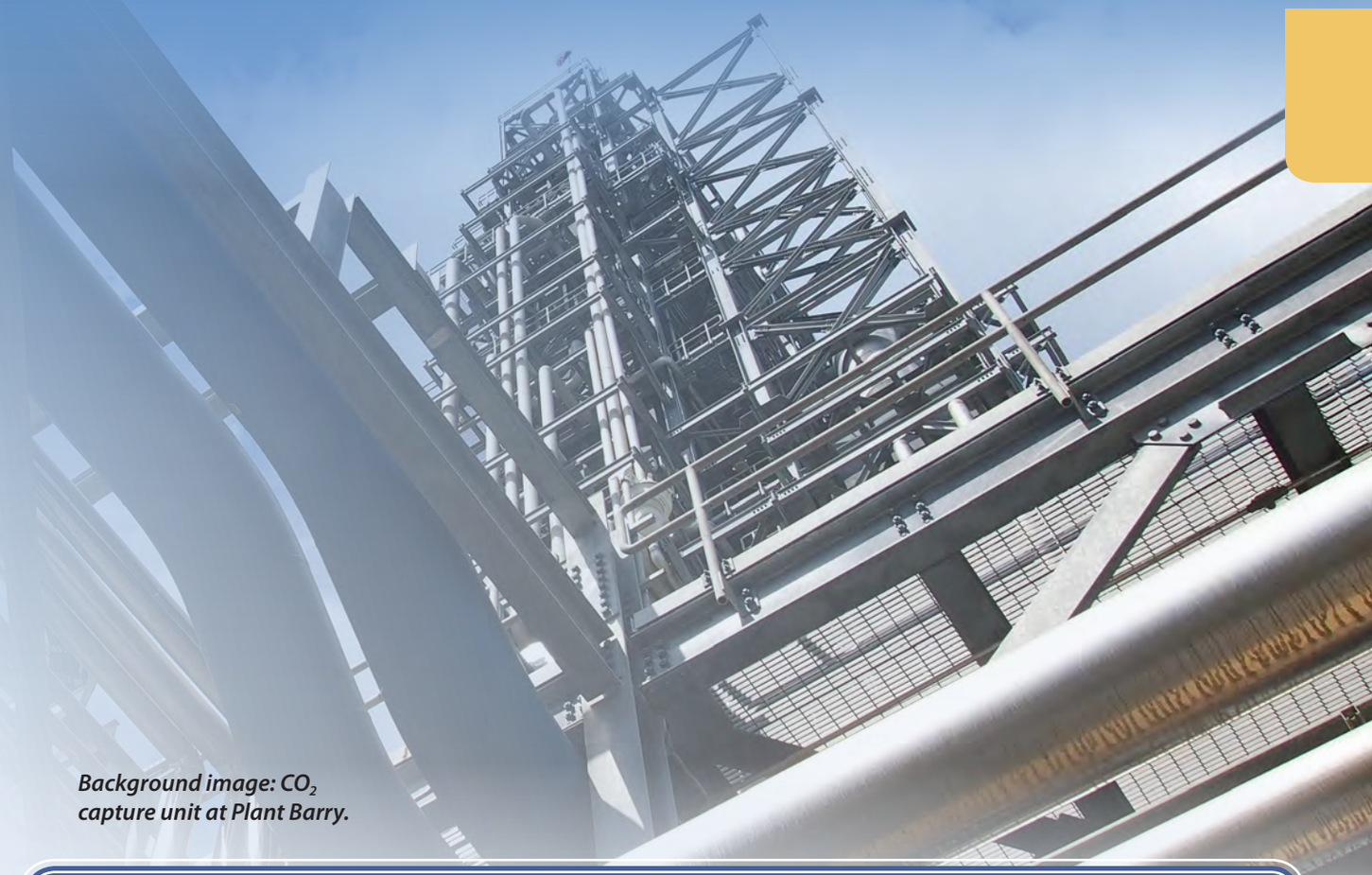
SECARB represents a 13-State region, including Alabama, Arkansas, Florida, Georgia, Louisiana, Mississippi, North Carolina, South Carolina, Tennessee, eastern Texas, Virginia, and portions of Kentucky and West Virginia. There are significant geologic storage and EOR opportunities in the SECARB region.

During project development, the SECARB partners focused on designing and operating a fully integrated project that would demonstrate the full CCS value chain from a coal-powered electricity generating facility (the CO_2 source) to a regionally significant geologic storage formation. To encourage similar project development in the region to support CO_2 emissions mitigation at the largest stationary CO_2 sources, several technical, legal, regulatory, and financial concerns and questions need to be addressed.

The Citronelle Project seeks to achieve the following objectives:

- Design and operate the United States' largest commercial prototype pulverized coal integrated CCS project
- Investigate the CO_2 flow, trapping, and storage mechanisms, locally and regionally
- Demonstrate the reservoir's ability to maximize CO_2 storage and minimize the areal extent of the CO_2 plume
- Investigate the adaptation of commercially available oilfield tools and techniques for MVA application
- Investigate experimental CO_2 monitoring tools that hold promise for future commercialization
- Document the complete permitting process
- Assess and document a register of communication and project-related risks and a mitigation plan associated with the integrated project involving multiple entities and responsible parties
- Analyze and assess the integration of project components

The lessons learned from the Citronelle Project are applied at several CCS projects, including Mississippi Power's Kemper County Energy Facility.



Background image: CO_2 capture unit at Plant Barry.

REGIONAL CO_2 MITIGATION STRATEGY

In recent years, States have taken steps to incentivize the utilization of CO_2 for EOR and other commercial uses. Within the SECARB region, the State legislatures of Alabama, Florida, Kentucky, Louisiana, Mississippi, Oklahoma, Tennessee, Texas, and West Virginia have passed several laws since 2007 supporting commercial-scale CCS project deployment in their States. These laws address topics ranging from pore space and CO_2 ownership, long-term liability, financing sources and tax incentives (e.g., severance, ad valorem, sales, and/or franchise), eminent domain, offshore carbon repository program, and organization (e.g., authority/jurisdiction over CO_2 injection wells for oil and gas production and/or pipeline transport). The Southern States Energy Board compiles an annual *Energy and Environmental Legislative Digest* of energy and environmental legislation passed in its member States. This document is distributed within the region and is a trusted resource for State policymakers when considering new laws on energy and environmental issues in their respective States.

SECARB will continue to collect data regarding regional CO_2 sources and emissions and potential geologic storage options. Stakeholder involvement through education and outreach activities will foster additional support for commercial CCS deployment within the region.

CRANFIELD PROJECT

SECARB
Southeast Regional Carbon Sequestration Partnership

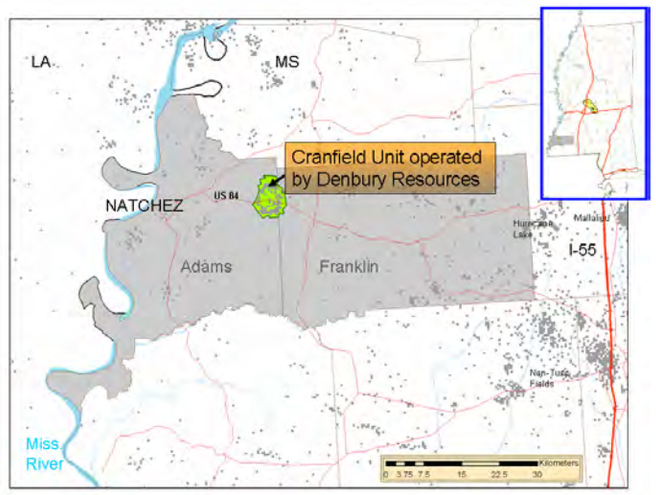
Introduction

The Southeast Regional Carbon Sequestration Partnership (SECARB) Cranfield Project has a goal of safely demonstrating large-scale, long-term CO_2 injection and storage in a CO_2-enhanced oil recovery (EOR) and associated saline reservoir that holds significant promise for future development within the southeast United States. In July 2008, Denbury Onshore, LLC, began CO_2-EOR operations at the Cranfield oilfield located east of Natchez, Mississippi. The SECARB Cranfield Team, led by the Gulf Coast Carbon Center of the Bureau of Economic Geology at the University of Texas at Austin, has deployed a variety of monitoring, verification, accounting (MVA), and assessment technologies to investigate the monitoring of storage in a commercial CO_2 injection environment and collect data for long-term carbon capture and storage (CCS) analysis.

The project's technical approach is based on the Regional Carbon Sequestration Partnership (RCSP) Initiative's goals of assessing permanence and capacity from a research and development (R&D) perspective. Research is underway in four areas: (1) the High Volume Injection Test area (HiVIT); (2) the Detailed Area of Study (DAS); (3) the Geomechanical area; and (4) the near-surface observatory. Carbon dioxide injection started in December 2009 at the DAS.

The CO_2 is injected into the lower Tuscaloosa Formation, a large and regionally extensive saline formation with the potential to hold centuries of CO_2 emissions in the Southeast United States. In August 2009, the project team met a milestone of monitoring an injection of more than 1 million metric tons of CO_2. The project team has monitored the injection and storage of more than 5 million metric tons of CO_2 at the site, as of March 2015.

In November 2009, the U.S. Department of Energy (DOE) recognized the Cranfield Project for furthering CCS technology and meeting a Group of Eight goal for the deployment of 20 similar projects by 2010. The Cranfield Project is the fifth project worldwide to reach this CO_2 injection volume while being monitored to demonstrate storage effectiveness and the first in the United States.



The location of the Cranfield Project site.

PROJECT HIGHLIGHTS

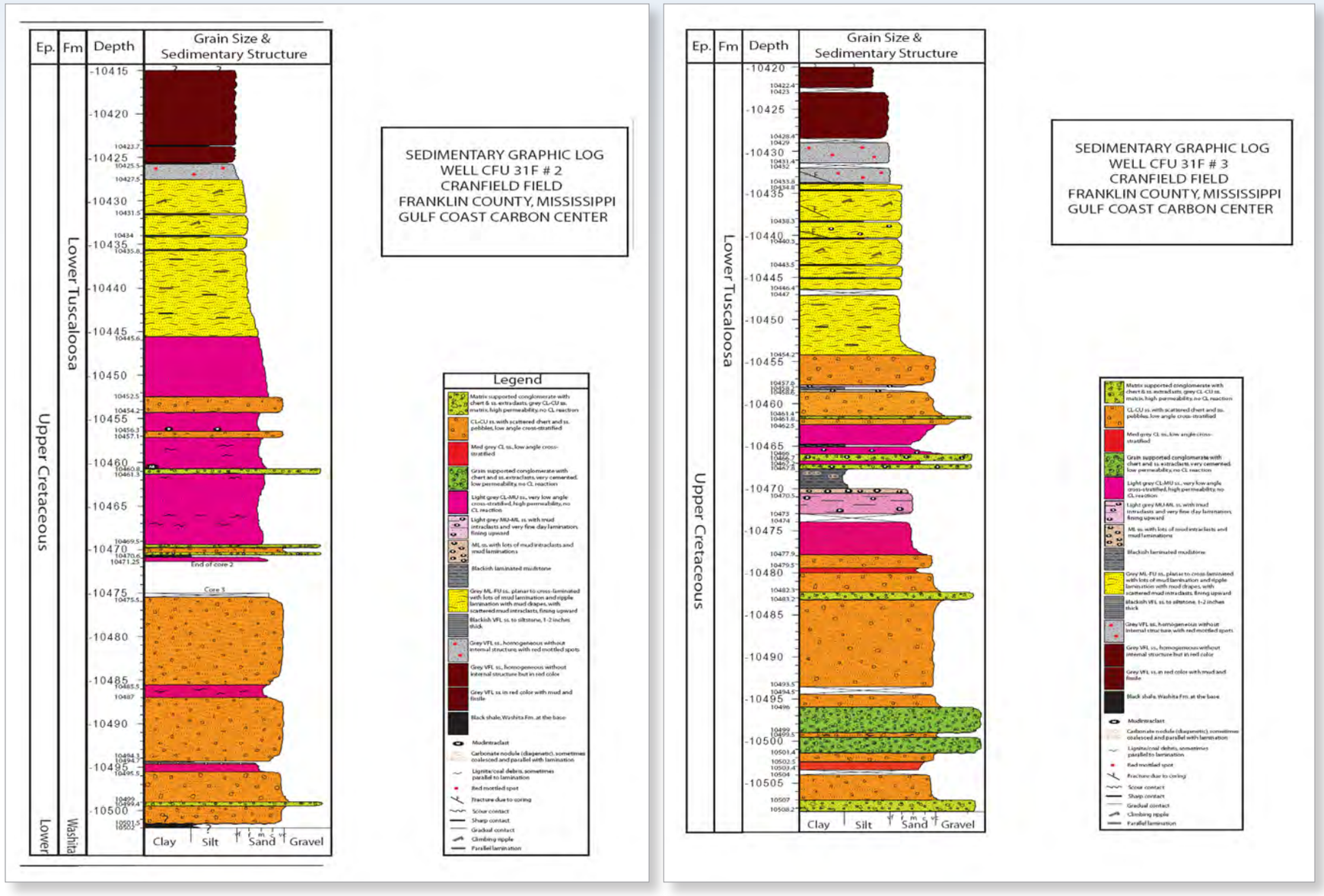
- SECARB partners and researchers worldwide utilize the data collected at Cranfield to further refine reservoir models for similar geologic settings.
- The Cranfield Project team began monitoring the CO_2 injection in 2008 as part of the RCSP Initiative's Validation Phase and continued the program in the HiVIT and DAS areas of the unit in 2009. Utilizing more than 20 wells for the CO_2-EOR operation, the cumulative volume stored has exceeded 5 million metric tons.
- The casing-deployed crosswell electrical resistance tomography (ERT) tool at Cranfield is the deepest worldwide and the first to be used in the United States at a geologic storage project. The ERT has been successful in producing images that show daily changes in CO_2 saturation. ERT data were collected several times a day from December 2009 until February 2011 (approximately 14 months).
- The Cranfield Project team is pioneering the first CCS project use of pressure surveillance in an above-zone monitoring interval (three installations).
- In 2010, the Carbon Sequestration Leadership Forum (CSLF) recognized the Cranfield Project for its outstanding accomplishments in advancing MVA technologies.

Site Characterization

The Cranfield Project is located approximately 19 kilometers (12 miles) east of Natchez, Mississippi. Denbury Onshore, LLC, is currently operating a commercial CO_2 flood of this field (using the subsurface injection of CO_2 for EOR). The SECARB Cranfield team characterized the surface and subsurface of the Cranfield site. Numerical models were developed and used to quantify the response of the reservoir to injection and migration of fluids. Monitoring was used to validate the conceptual and quantitative predictions made in the models and to support project goals.

Characterization is recognized as the cornerstone of monitoring and modeling. Extensive reservoir data for formation characterization was available at the start of the study and augmented by the collection of log suites, hydrologic investigations, two reservoir cores, and one mudrock core. The SECARB Cranfield Team used stratal slicing to assess the 3-D seismic volume. The project team also applied a risk assessment methodology to consider potential CO_2 pathways to the surface. The project team developed novel distributed temperature and above-zone pressure monitoring systems to assess the design effectiveness of isolation of the injection zone.

The Cranfield Unit is in a large, domical structure at depths greater than 3,000 meters (10,000 feet) with a gas-tight geologic seal. The target injection zone is in the lower Tuscaloosa, above a regional conformity, in valley-fill-fluvial sandstones and conglomerates separated by alluvial and overbank within-unit seals. The reservoir is composed of stacked and incised channel fills and is heterogeneous, with flow unit average porosities of 25 percent and permeability ranging from 50 millidarcies to 1 Darcy. Chlorite and quartz are the major cements. The lowest element of the regional confining system is the thick marine mudstone portion of the middle Tuscaloosa, which is overlain by numerous confining beds. An additional major confining unit is the thick mudrocks of the Midway Formation, below the Wilcox productive reservoir. Confining system efficacy is demonstrated by hydrocarbon accumulation.



A comparison of the graphic core logs of the observation wells, CFU 31F-2 and CFU 31F-3, provides a visual representation of the heterogeneous reservoir. Courtesy of the Gulf Coast Carbon Center (Prepared by M. Kordi).

Risk Assessment, Simulation, and Modeling

The SECARB Cranfield Team's risk management efforts focused on assessing operational risks related to the site and demonstrating a formal risk assessment methodology supported by DOE through the Carbon Capture Project (CCPII), known as the Certification Framework (CF). The CCPII team performed a risk assessment for the site. The continuity and high capillary entry pressure of the confining system is demonstrated by the accumulation of commercial volumes of methane. It is further confirmed by mapping stratigraphic continuity of the confining system of the middle Tuscaloosa Formation through wireline log correlation, seismic interpretation, and collection of a 20-foot core that was subject to capillary entry pressure analysis.

The oilfield operator, Denbury Onshore, LLC, constructed more than 20 injection wells at the site during the monitoring project period. Four of these wells are completed below the oil-water contact into the “water leg” to support the Cranfield Project goals. Two new wells were constructed at the DAS to serve as observation wells.

The risk assessment identified vintage wells as the most significant risk. More than 60 1945-1950 vintage wells intersect the injection interval. This risk is managed by the oilfield operator in accordance with Mississippi State regulations for the oil and gas industry.

The project team employed numerous monitoring techniques, including a first deployment of pressure surveillance in the above-zone monitoring interval to collect data on the performance of the lower part of the confining system. Soil gas and groundwater were monitored field wide and a detailed assessment of soil gas was conducted at the P-site (a near-surface laboratory to study a plugged and abandoned [P&A] well, well pad, historic fluid disposal pit, and natural plant activity). The project team is assessing the effectiveness of groundwater monitoring as a field-wide detection tool.

The Cranfield Project employs an integrated simulation and modeling program to develop interpretable and significant research results from monitoring the CO_2 flood. The integrated program begins with characterization and extends through several types of predictive modeling, including monitoring planning, monitoring modification in response to improved data, and monitoring long-term injection. This iterative process requires integration of expertise from various disciplines. It is important to use modeling to assess uncertainties that result from each data collection effort, including the syn- and post-injection monitoring, and focus data collection on reducing uncertainties.

A consortium conducts the modeling program at Cranfield using an array of tools and approaches. A suite of subsurface modeling tools have been deployed, including: analytical assessment of pressure from gas storage literature; one-dimensional seal flux assessment; an innovative use of simplification of fluid properties to represent water, oil, and gas in the far field; GEM-CO2 for the multiphase fields; and COMSOL for the geomechanical assessment. Multiple probabilistic realizations of the quantitative static geocellular model have been constructed in Petrel and input into GEM-CO_2 for assessment of multiphase flow in the east side of the field around the DAS. For geochemical assessments, PHREEQC and Geochemists workbench are used for single phase regions; CORE2D and TOUGHREACT are used to model multiphase reactive volume transport and multiphase flow. Other teams, including LBNL, Lawrence Livermore National Laboratory (LLNL), and DOE’s Center for Frontiers of Subsurface Energy Security group, have modeled various perspectives of flow at Cranfield. The SECARB Cranfield Team provided data and observations to the approach comparison study SIM-SEQ.

Task	Step	Name	Description
1	1	Project Definition	Gather information on location, injection depth, properties of the formation, injection rate, number of wells, duration of injection, etc.
	2	Define Storage Region	Supplement the project definition with a practical and acceptable definition of the boundaries of the storage region.
	3	Identify Vulnerabilities	For example, wells and faults are potential release pathways; and hydrocarbon and mineral resources, potable groundwater, near-surface environment, health and safety, and the atmosphere are potentially vulnerable entities that are grouped into "compartments" in the Certification Framework.
2	4	Characterize Vulnerabilities	Determine properties of wells, faults, and caprock to the extent possible; and determine properties of the compartments in which impacts may occur.
3	5	Injection and Migration Modeling	Simulate injection and migration of CO_2 and brine pressurization (or use catalog or other existing results) to estimate sizes of the CO_2 plume and pressure perturbation.
	6	Estimate Likelihood of Release	From simulation results and spatial characterization of release conduits, estimate the probability of release.
	7	Model Impacts of Release	Use specialized models in the Certification Framework to calculate fluxes or concentrations in the compartments as a function of time.
4	8	Risk Calculation	Calculate CO_2 release risk and brine release risk.

The Certification Framework is used to analyze release risk associated with subsurface processes and excludes compression, transportation, and injection-well release risk. Courtesy of the Gulf Coast Carbon Center, J. P. Nicot.

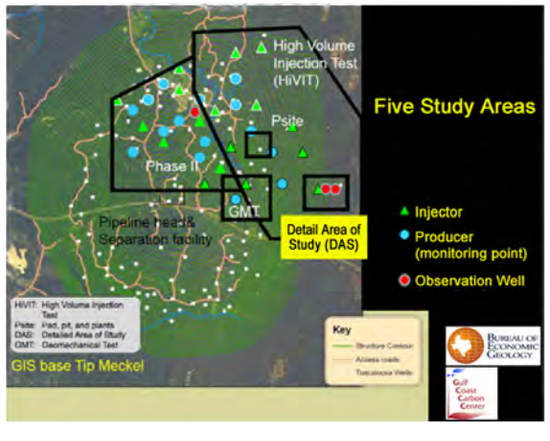
Site Operations

The original research objective of the Cranfield Project was to monitor a large-volume CO_2 injection (1.5 million metric tons over 1.5 years) to demonstrate retention and improve quantification of storage capacity. In collaboration with Denbury Onshore, LLC, and its commercial CO_2-EOR project, the project team designed specialized infrastructure to achieve these goals. SECARB's study operations occur in four integrated research program areas within Cranfield field: (1) the High Volume Injection Test area (HiVIT); (2) the Detailed Area of Study (DAS); (3) the Geomechanical area; and (4) the near-surface observatory, also called the "P-site." Carbon dioxide injection activities occur at the HiVIT and the DAS. Carbon dioxide from Jackson Dome, a natural source, is delivered to the Cranfield oilfield via pipeline.

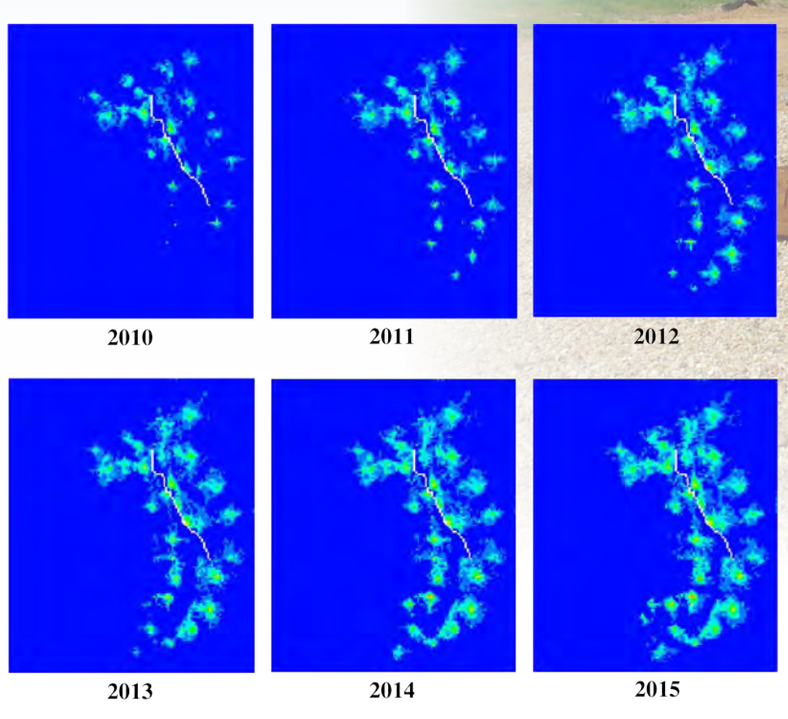
The HiVIT program started on April 1, 2009, at an initial rate of 40,000 metric tons of CO_2 per month, with the University of Mississippi and Mississippi State University conducting pressure and fluid sampling through far-field wells and regional groundwater monitoring. The HiVIT reached the 1 million metric ton per year target rate in December 2009 and the 1.5 million metric tons stored target in the spring of 2011.

The DAS is located down-dip of the oil-water interface of the Cranfield oilfield. It is designed to allow the observation of fluid flow between two instrumented wells through a crosswell multi-physics monitoring program. The well layout includes one injection well and two down-dip observation wells. These wells were drilled and completed from June through August 2009. The wells are situated on the same well pad and located 112 meters (367 feet) apart. Sixty-eight meters (223 feet) lie between the injector and the first observation well and another 44 meters (144 feet) separate the second observation well.

When the CO_2 arrives at the field, the volume is measured at the purchase pump, injection pressure is boosted to 2,900 psi, and the CO_2 is distributed across the field via a buried pipeline system. Injection rate and pressure is recorded several times daily at each wellhead. The team has met its objective by monitoring more than 5 million metric tons of CO_2 stored. Recycle now dominates the injection, but make-up CO_2 volumes cause the volume stored to continue to accumulate. The importance of CO_2 production and recycle is documented by the cumulative injection of 11 million metric tons of CO_2, showing that some CO_2 has been injected several times. This evolution provides information on the relationships between storage and use of CO_2 for EOR.



Map showing DAS at Cranfield oilfield.



Modeled CO_2 distribution map with time during field development on the eastern side of Cranfield. The reference map shows the CO_2 injection wells relative to the study areas. The light blue portions on the six images represent the CO_2 distribution with time.

Background image: The Cranfield Project's DAS, including one CO_2 injection well in the distance (red well) and two monitoring wells in the foreground (gray wells).

Monitoring, Verification, Accounting, and Assessment

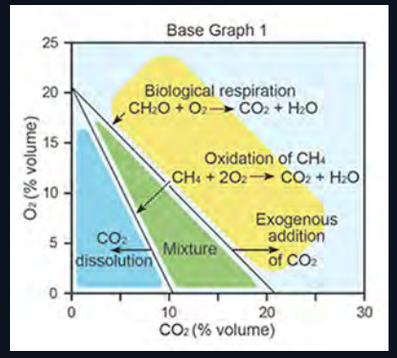
SECARB adheres to a vigorous MVA program. For the Cranfield Project, sweep efficiency is monitored by saturation measurements along well bores, crosswell measurements, and vertical seismic profiling (VSP) and/or surface seismic methods. The Cranfield Project team designed a field-wide monitoring program to document the storage of large volumes of CO_2 and several focused field area projects. This documentation meets DOE's objectives of improving quantification of capacity and storage effectiveness. The field-wide area includes the north and east parts of the Cranfield oilfield that are under CO_2 flood during the project period. Focus areas include the soil gas study area known as the "P-site" and the DAS, an area with two dedicated observation wells down dip of an injection well.

The technologies used in field-wide monitoring include time-lapse 3-D seismic survey, area-wide groundwater and soil gas surveillance, and a six-well microseismic array fielded by the Research Institute of Innovative Technology for the Earth (RITE) of Japan. Commercial production data provides important calibration points for the modeling. The 3-D seismic survey was interpreted to show CO_2 accumulation and has been used to add confidence in the fluid flow model. No indication of release to shallower zones was found on the time-lapse, 3-D seismic survey. No microseismicity related to CO_2 injection was detected at the site as part of the RITE study. A controlled experiment, aquifer characterization, and reactive transport modeling have been used to determine the sensitivity of this method to CO_2 release into the formation. An airborne magnetic and conductivity survey was conducted as an experiment to better characterize the shallow subsurface. Well locations were identified with high accuracy in the airborne survey. No change in groundwater attributable to CO_2 release was identified.

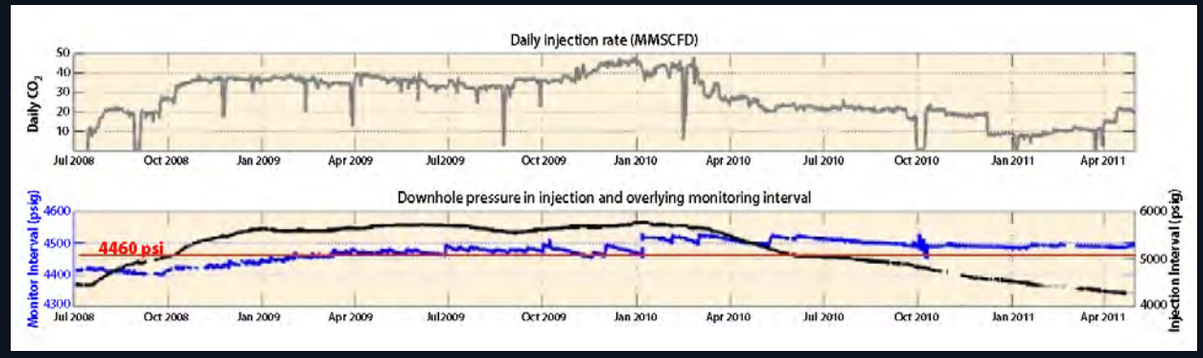
Background image: Observation well at the DAS, CFU 31F-3.

The "P-site" study assessed a local high methane concentration with ratios of nitrogen (N_2), oxygen (O_2), CO_2, and methane indicative of gas migration. Gas ratios and stable isotopic relationships show that methane has been microbially oxidized to CO_2. Modern C^{14} of the soil gas shows that it is not sourced from the target formation.

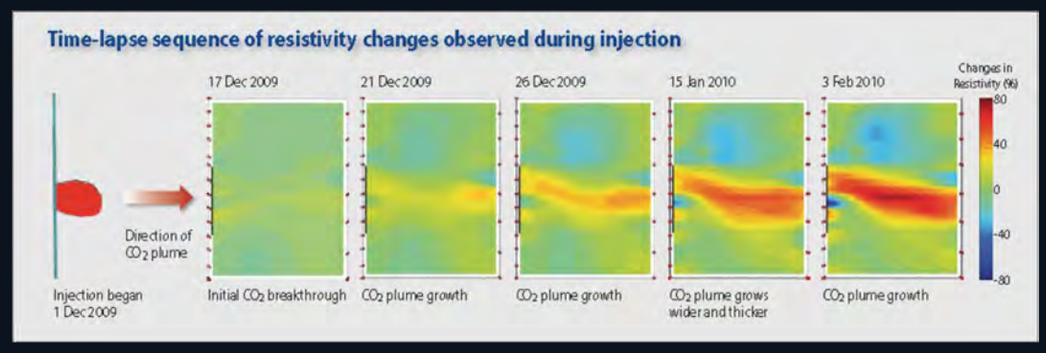
At the DAS, approaches using different physics were employed to assess how CO_2 migrated through the stratigraphically and diagenetically complex sand-rich fluvial injection zone. A first-of-its-kind, deep electrical resistance tomography (ERT) deployment was conducted between wells and inverted to provide high frequency (daily) images of the change in the resistivity as CO_2 was substituted for brine. The inversions show that flow was not radial, but occupied channels that meander into the imaged plane, with higher saturation developing at the well furthest from the injection well. ERT appeared to be sensitive to saturation over a wide range. A tracer program also documented the same effect, with "fast paths" developing at higher injection rates. Carbon dioxide moved through a channel that intersects the far monitoring well, while tracers arrive more slowly through non-channel facies to the nearer monitoring well. For the first time, geochemical sampling also detected the process where dissolving CO_2 results in methane coming out of solution. Variations in ratios of exsolved methane to CO_2 document changes in contact of CO_2 with brine saturated with methane over time. During the field project, the closely spaced well array at the DAS (68 meters between the injector and the first observation well and another 44 meters to the far observation well) allowed unique observations of fluid flow in a complex reservoir. Stochastic methods in history matching fluid flow in heterogeneous geologic environments are needed to capture the possible range of responses to injection and determine the risks created by uncertainty. The fluid geochemistry showed low reactivity that increased over time. This was interpreted as a result of non-reactive coats of chlorite cements on grains.



The P-site research is a type of process-based monitoring that does not require years of background measurements to determine the source of CO_2 in the near subsurface. Using simple gas ratios (CO_2, CH_4, N_2, O_2) methods were developed to discern several CO_2 sources and sink such as biologic respiration, CO_2 dissolution, oxidation of CH_4 into CO_2, and others.



The Above Zone monitoring Interval (AZMI) pressure response (black line) in relation to the injection formation pressure (blue line).



The casing-deployed crosswell ERT has been successful in producing images that show weekly changes in CO_2 saturation. Courtesy of C. Carrigan, and X Yang, LLNL, and D. LaBrecque, Multi-Phase Technologies.

Public Outreach, Knowledge Sharing/ Dissemination

The SECARB Cranfield Team has an active public outreach program that falls under a formal communications plan. Conducting effective public outreach involves listening, sharing information, addressing concerns, and communicating project risks early and often. The Southern States Energy Board leads the international, national, and regional effort, and the individual field teams lead site-specific public outreach activities. At Cranfield, local outreach is managed by professional landmen who share information regarding project activities with the residents in and around the oilfield.

Project activities and outreach efforts at Cranfield began under the RCSP Initiative's Validation Phase and continue today. The team has excelled in creating a collaborative environment and opportunity for industry, national laboratories, the U.S. Geological Survey (USGS), and academic interaction. The site has hosted many experiments within and outside of the RCSP Initiative, such as the National Risk Assessment Partnership (NRAP), the Carbon Capture Project, GEO-SEQ project, the Center for Frontiers of Subsurface Energy Security, and other targeted projects. The public outreach activities are influencing decision makers who are designing the next phase of commercially oriented monitoring.

Team members have shared details of the Cranfield Project with various audiences through numerous international knowledge sharing events, presentations, and poster sessions at conferences and workshops. The extensive outreach and knowledge sharing efforts have enabled team members to share the results of the Cranfield Project with various audiences. The team hosts site visits, provides responses to local and trade media, maintains current fact sheets, and posts project information, including outreach activities, on a dedicated "Bookshelf" hosted by the Gulf Coast Carbon Center. The SECARB website offers current fact sheets, photos of field activities, news, and upcoming and recent events. Project activities and lessons learned are communicated through multiple electronic sources, including an annual briefing to SECARB stakeholders, email notifications, and social networking.

Visitors examine core samples collected at the Cranfield Project site.

Background image: The project team hosts a field trip for the American Association of Petroleum Geologists in April 2010. Participants surround the injection well located at the DAS.

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Commercialization of CCS in the SECARB Region

Early opportunities for the commercialization of CCS in the SECARB region will most likely be associated with offsetting the cost of capturing and storing CO_2. Utilizing CO_2 for EOR is the primary candidate to offset costs in several SECARB States, such as Louisiana, Mississippi, and Texas. The CO_2 currently used for EOR is transported from the Jackson Dome, a natural source of CO_2 located near Jackson, Mississippi. Denbury Onshore, LLC, operates a pipeline network that transports Jackson Dome CO_2 to oilfields in the southeast United States. In the past few years, several anthropogenic sources have been added to Denbury's pipeline system. As a result, the Denbury pipeline system has the potential for becoming the regional backbone of an integrated source-storage formation network for CO_2.

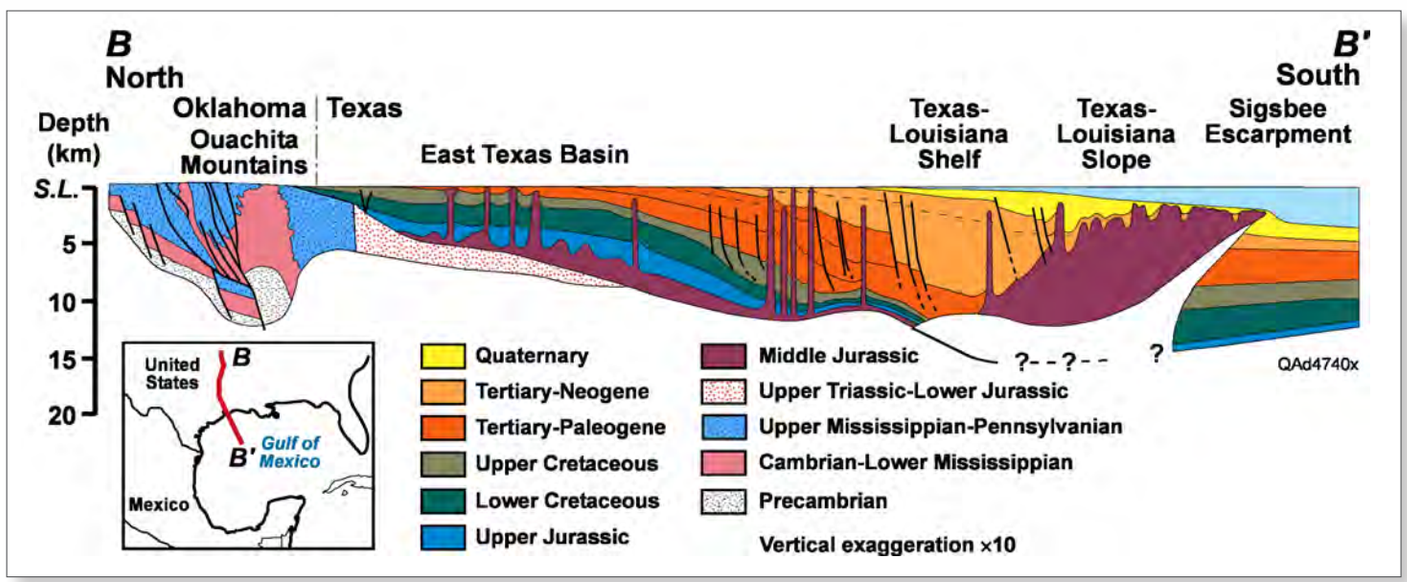
Reliable modeling and monitoring are required to ensure that geologic storage is an effective method for reducing atmospheric CO_2 concentrations. The Cranfield Project team is evaluating the high-rate and high-volume injection at the CO_2-EOR site to guide evolution from experimental to commercial monitoring protocols and improve geologic CO_2 storage resource estimation.

Additionally, the Tuscaloosa Formation has similar properties to formations found in other locations across the Nation that may be suitable for geologic storage. The project team has monitored the storage of more than 5 million metric tons of CO_2 since 2008. Substantive knowledge sharing is underway to share data, results, and lessons learned from this long-term monitoring program with the regional, national, and international community in an effort to further encourage CCS commercialization.

REGIONAL CO_2 MITIGATION STRATEGY

In recent years, states have taken steps to incentivize the utilization of CO_2 for EOR and other commercial uses. Within the SECARB region, the state legislatures of Alabama, Florida, Kentucky, Louisiana, Mississippi, Oklahoma, Tennessee, Texas, and West Virginia have passed several laws since 2007 supporting commercial-scale CCS project deployment in their states. These laws address topics ranging from pore space and CO_2 ownership, long-term liability, financing sources and tax incentives (e.g., severance, ad valorem, sales, and/or franchise), eminent domain, offshore carbon repository program, and organization (e.g., authority/jurisdiction over CO_2 injection wells for oil and gas production and/or pipeline transport). The **Southern States Energy Board** compiles an annual *Energy and Environmental Legislative Digest* of energy and environmental legislation passed in its member states. This document is distributed within the region and is a trusted resource for state policymakers when considering new laws on energy and environmental issues in their respective states.

SECARB will continue to collect data regarding regional CO_2 sources and emissions and potential geologic storage options. Stakeholder involvement through education and outreach activities will foster additional support for commercial CCS deployment within the region.



The Tuscaloosa Formation has properties similar to those found in other locations across the Nation that may be suitable for geologic CO_2 storage. Image courtesy of Galloway and others, 2000.

FARNSWORTH UNIT PROJECT

Introduction

The Southwest Regional Partnership on Carbon Sequestration (SWP) has partnered with Chaparral Energy of Oklahoma City, Oklahoma, to conduct a carbon capture and storage (CCS) project in northern Texas. Chaparral Energy is using anthropogenic carbon dioxide (CO_2) for enhanced oil recovery (EOR) within the Farnsworth Unit (FWU), Ochiltree County, Texas.

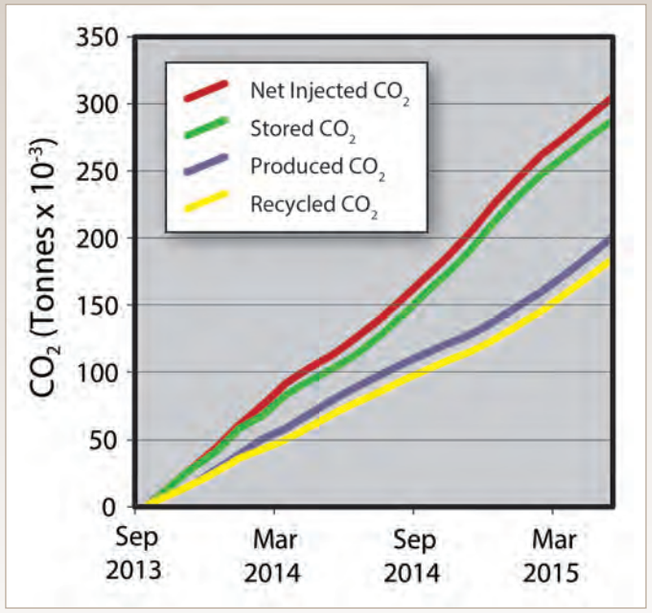
The injection target is the Pennsylvanian Upper Morrow Formation, an incised valley-fill coarse sandstone in the Anadarko Basin. Within the Farnsworth Unit, the Morrow has produced more than 19 million barrels of oil and 44 billion cubic feet (ft^3) of gas. Preliminary estimates of CO_2 storage capacity of the Morrow within the Farnsworth Unit exceed 25 million metric tons.

The CO_2 injected is 100 percent anthropogenic; it is captured, compressed, and transported via pipelines from a fertilizer plant in Texas and an ethanol plant in Kansas. The SWP maintains a daily detailed inventory of the CO_2 delivered to and stored at the Farnsworth Unit for use as carbon offsets. The Farnsworth Unit Project will serve as a blueprint for future commercial-scale CCS projects.

PROJECT HIGHLIGHTS

- Approximately 300,000 metric tons of 100 percent anthropogenic CO_2 permanently stored in the subsurface; more than 1,000,000 metric tons injected by 2018.
- Farnsworth Unit has 13 active CO_2 injection wells. Three wells drilled by the SWP are dedicated to characterization and monitoring the fate of injected CO_2.
- Extensive advanced log suites obtained for new wells; core collected through injection interval and overlying shale/limestone seal rocks. Both used to calibrate seismic models and develop extensive 3-D reservoir models.

Location of the SWP Farnsworth Unit Project within the Anadarko Basin.



Summary of the Farnsworth Unit CO_2 inventory since 2013.

Site Characterization

Initial site characterization efforts have provided a wealth of surface and subsurface data to serve as a baseline for all future simulation and MVA activities. The SWP site characterization efforts will continue throughout the lifetime of the project.

Characterization data includes:

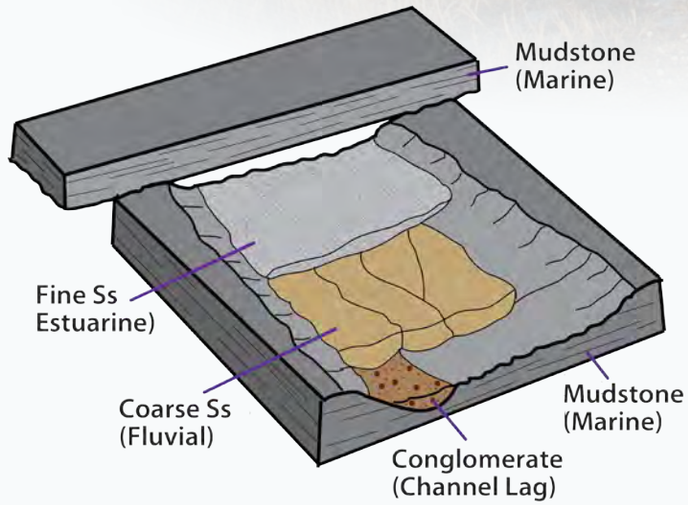
- Seismic data - including a baseline 3-D survey at Farnsworth, and two nearby surveys connected by 2-D seismic lines for the purpose of basin-scale petroleum systems modeling
- Baseline and repeat 3-D vertical seismic profiles (VSP) and crosswell data at the injection/characterization wells
- Legacy well data - geophysical logs from more than 140 wells in the field, core data from 47 wells, and slabbed core and thin sections from 8 old wells
- New well data - more than 750 feet of core, comprehensive log suites from three new wells; petrophysical, geochemical, geomechanical, petrographic analyses of reservoir and seal units from core

The seismic and core data is analyzed to create and update a detailed 3-D geologic model of the Farnsworth Unit. This geologic model has improved our understanding of FWU lithofacies, shedding light on depositional and diagenetic processes and their effect on reservoir architecture and behavior.

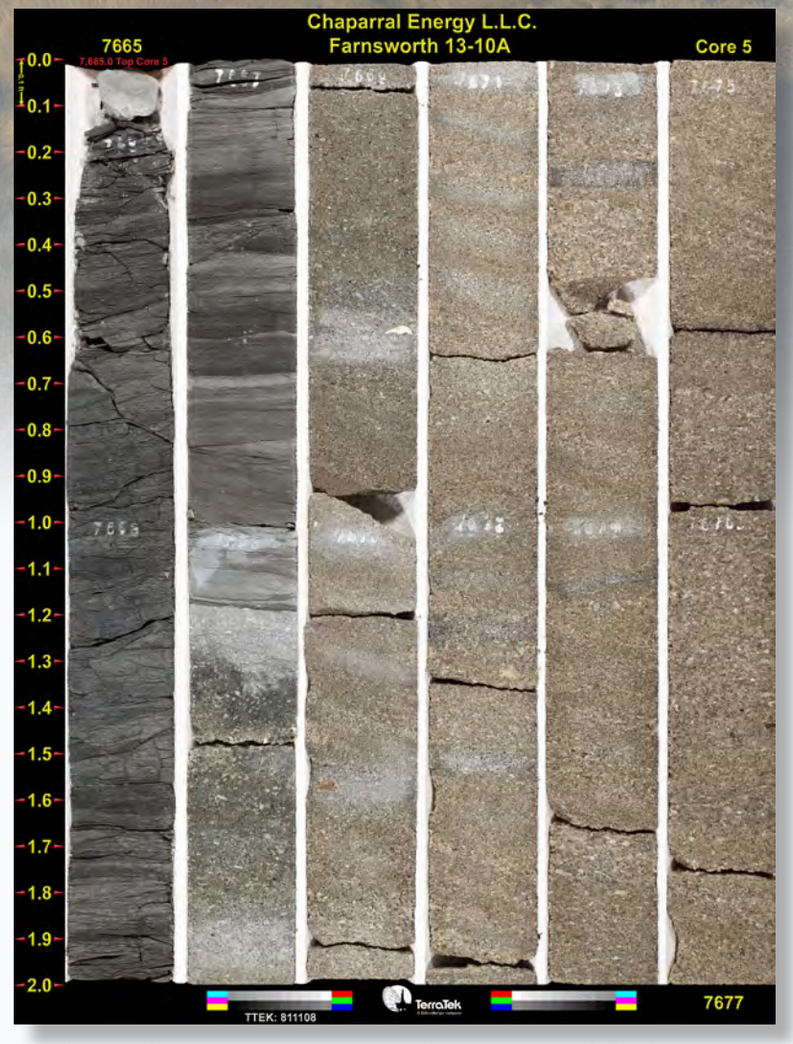
The geologic model has been used to evaluate:

- Reservoir properties
- CO_2 storage capacity/injectivity
- CO_2 trapping mechanism
- Potential injection/production-induced reservoir/seal damage

Fine scale geophysical data continues to refine the model for simulation of near-well-bore processes, while regional scale seismic data will help to upscale our reservoir model from the field from reservoir to basin scale and enhance understanding of tectonic history and current structural regime.



Depositional model for the Farnsworth Unit. From Gallagher (2014), modified from Wheeler et al. (1990) and Puckette et al. (2008).



Core from well 13-10A at the Farnsworth Unit. Gray rock (left) represents the seal for the Morrow sandstone reservoir (right).

Background image: 3-D seismic survey being performed at the Farnsworth Unit.

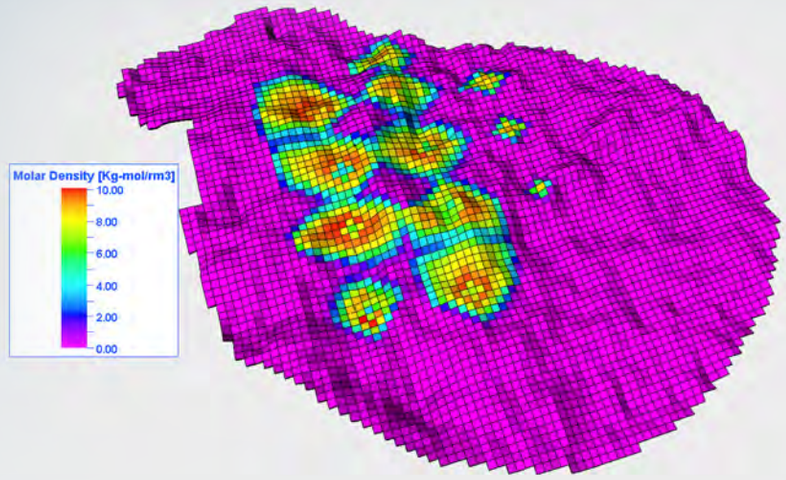
Model Simulation and Analysis

Perhaps the most critical tool for all CCS projects, especially geologic storage projects, is simulations and predictions based on our best geologic models. Simulation is used to analyze the complex Site Characterization and MVA data sets, and quantify risks and forecast outcomes at the Farnsworth CCS-EOR field. The SWP is applying a suite of numerical simulators to understand the complex coupled subsurface processes associated with injecting CO_2 and water into the Farnsworth Unit for enhanced oil recovery and storage of CO_2, but is additionally developing a scientific numerical simulator with fully coupled multifluid hydrologic, heat transport, reactive transport and geomechanics (HTCM) capabilities.

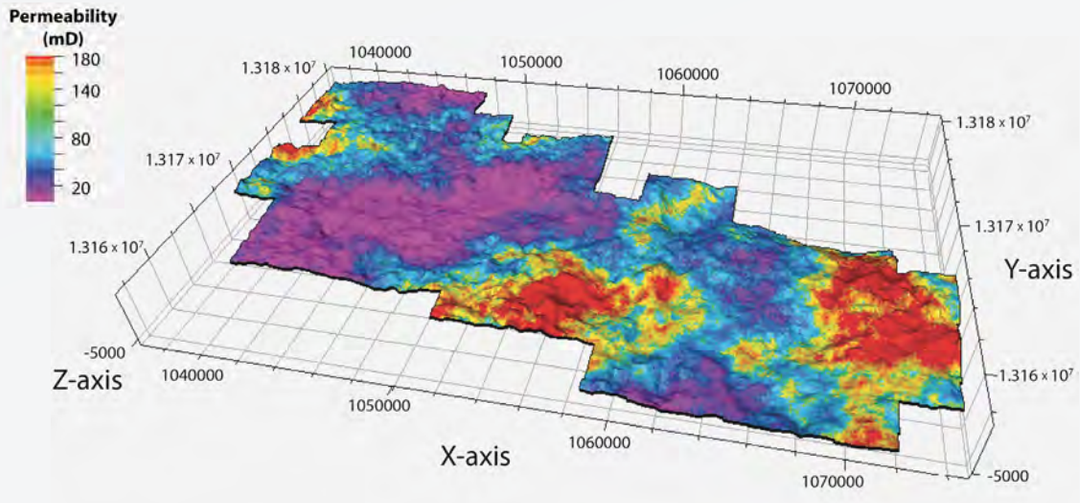
This simulator is specifically designed to serve as a research tool, allowing scientists and engineers to explore new models for describing three-phase relative permeability, mixed wettability capillary pressure-saturation functions, and compositional fluid phase behavior, within a numerical simulator framework. The Farnsworth Unit is a particularly challenging site to model because of the unique relatively high miscibility pressure of the Farnsworth oil, the complex depositional history yielding local heterogeneities, and the stark contrast in petrophysical properties between the eastern and western halves of the unit. To meet the multi-tiered computational requirements for simulating the Farnsworth Unit, the numerical simulator being developed by SWP will function on computers ranging in class from shared-memory workstations to distributed-memory supercomputers.

Relative permeability and capillarity are attributes often treated superficially, but in the SWP we established these properties as one of the greatest sources of uncertainty of simulated geologic storage forecasts, and therefore among the greatest sources of risk. Thus, the Farnsworth CCS-EOR reservoir models include specially calibrated (new) relative permeability and capillary pressure formulations. An additional ongoing effort is explicit coupling between seismic velocity models and reservoir models. This attuned coupling facilitates real-time updates of reservoir properties as new seismic data are gathered and processed.

Finally, the SWP models are integrated systematically with ongoing MVA, Site Characterization and Risk Assessment in an iterative annual process.



Simulations of fluid flow were used to history match CO_2 injection in the model and provide a visual representation of CO_2 stored within the Morrow formation (Kg-mol/rm^3). Newest injection patterns are to the East.



Farnsworth Unit 3-D model grid, showing permeability of the Morrow Sandstone.

SIMULATION GOALS

- Forecast CO_2 storage capacity to within +/- 30 percent accuracy, and to determine exactly what is the uncertainty of that storage capacity.
- Forecast CO_2 migration and trapping mechanisms, including how much CO_2 is trapped by each mechanism and the associated uncertainty for each.
- Develop engineering design to maximize storage efficiency and ensure containment efficacy.
- Design optimized MVA approaches, as well as to conduct all calculations necessary for interpreting monitoring results.
- Conduct all calculations necessary to quantify risks, and the uncertainty associated with those risks.

Monitoring, Verification, Accounting, and Assessment

The Farnsworth Unit MVA program is designed to provide data needed to characterize injected CO_2 and existing reservoir fluids, including volumes of CO_2 injected, produced, and recycled; fluid migration; and identification and quantification of any potential release of CO_2 and/or fluids from the reservoir. The MVA data will be used to facilitate effective simulation results and risk assessment for underground sources of drinking water (USDWs) (Ogallala formation), the shallow subsurface, and atmosphere.

Monitoring CO_2 at surface:

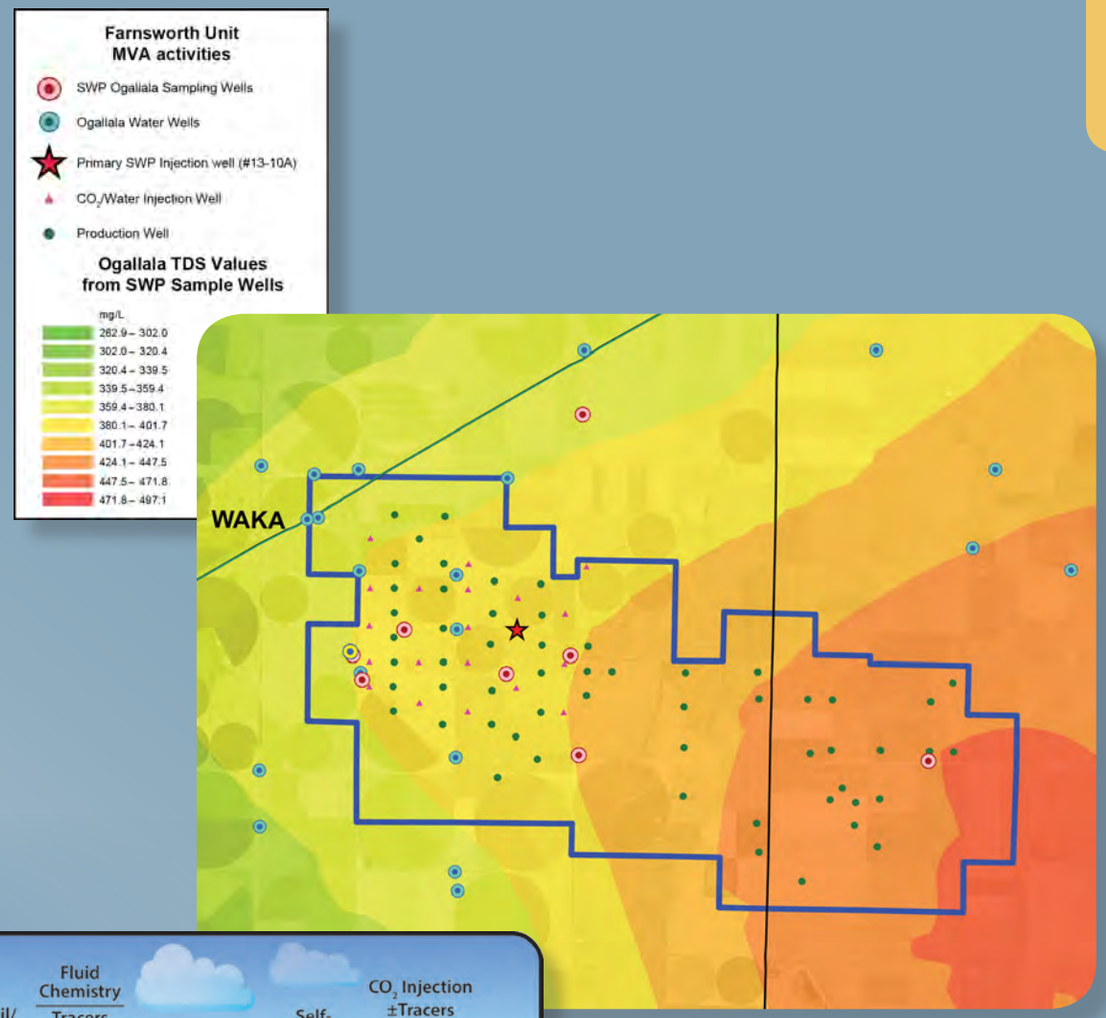
- Eddy covariance towers for measuring atmospheric CO_2 and methane fluxes; used to constantly monitor large areas for increases in gas emissions
- Handheld, remotely stationed and airborne sensor sweeps to track localized CO_2 concentrations
- On-surface flux measurements to detect possible CO_2 emissions from depth

Detecting CO_2 and/or effects of CO_2 in Non-Target Reservoir:

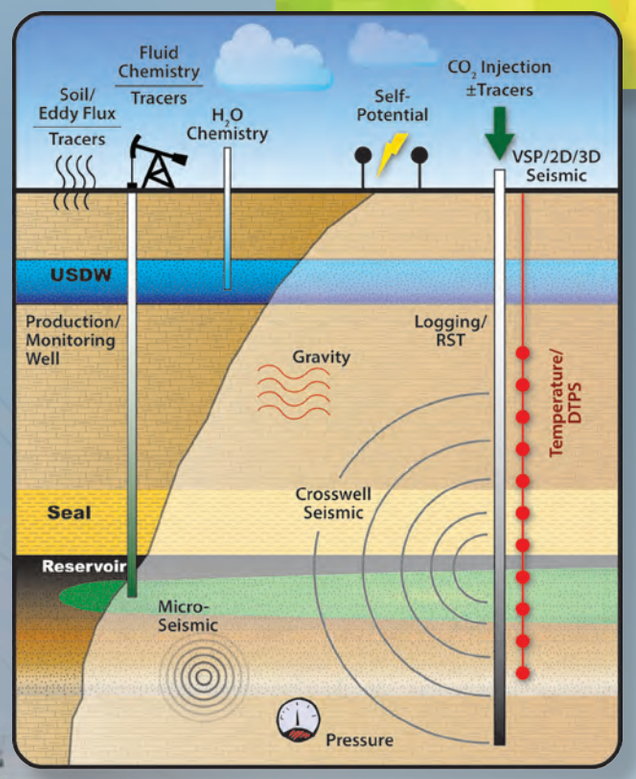
- Groundwater chemistry (USDWs)
- Water and Gas Tracers
- Self-potential (detection of minute electrical changes caused by subsurface fluid migration)
- Microgravity survey

Tracking CO_2 Migration and Fate:

- In situ pressure
- Distributed temperature array (DTS)
- 2-D/3-D seismic reflection surveys
- Vertical seismic profile (VSP), crosswell, passive seismic for detection of microseismic events
- Water/gas chemistry (target reservoir)
- Water/gas isotopes
- Gas Tracers



Above: Map of the Farnsworth Unit showing TDS trends within the Ogallala formation (higher concentrations to the east of the Unit).



Surface and sub-surface monitoring methods in use at the Farnsworth Unit (left).

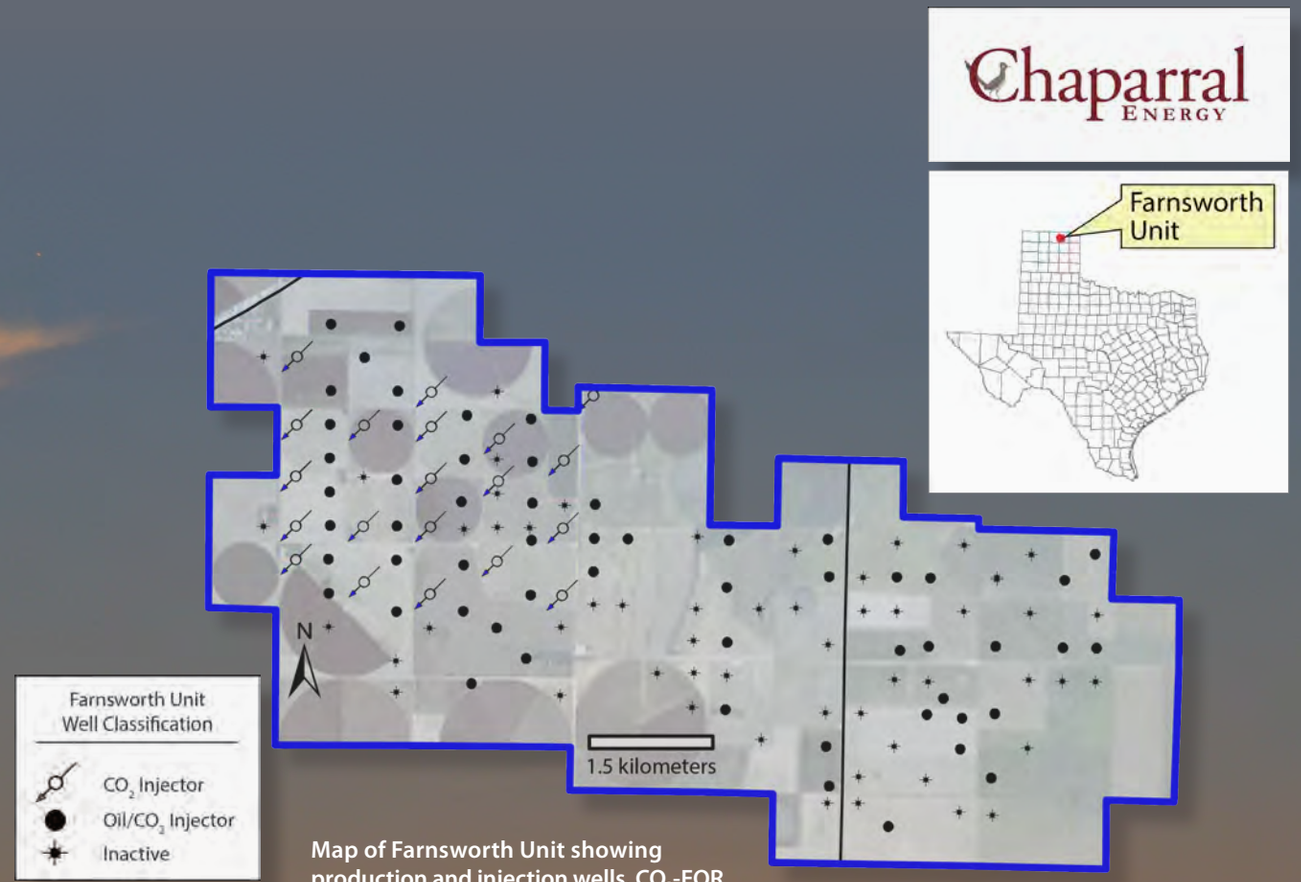
Background image: Well being drilled at the Farnsworth Unit.

Site Operations

Chaparral Energy began CO_2 injection in December 2010. Currently, CO_2 is being injected in 13 individual five-spot well patterns in the western side of the field. Three patterns initiated injection in December 2010, followed by two in 2011, three in 2012, one in 2013, and four in 2014. Patterns are being added as more CO_2 is available through purchase and recycled gas. A total of 25 patterns are planned for the western half of the field with one to five new patterns added each year.

The anthropogenic CO_2 sources are Agrium (fertilizer plant) at Borger, Texas, providing approximately 19.0 million standard cubic feet per day (MMscf/D) and Arkalon (ethanol plant) at Liberal, Kansas, providing approximately 15 MMscf/D; CO_2 from these plants are distributed among three Chaparral units in the area. Net CO_2 injection at Farnsworth is anticipated to be 10 MMscf/D (approximately 190,000 metric tons per year). This does not include recycled CO_2 that totals approximately 8 MMscf/D (as of May 2015). As of May 2015, purchased CO_2 has totaled 786,000 metric tons since the start of the EOR project (December 2010) and 304,000 metric tons since the SWP Phase III project officially commenced (October 2013) with net CO_2 storage of 731,000 and 288,000 metric tons, respectively. The remainder of CO_2 was lost to the atmosphere (flaring) during the recycling process, especially early in the CO_2-EOR project. Upgrades to the Farnsworth Unit infrastructure and operations now minimize the amount of flaring to less than 8 percent of the purchased CO_2.

Total crude oil production since December 2010 is 1,672,000 barrels with 1,114,000 since October 2013. Approximately 97 percent of the present production is attributed to CO_2 EOR. Farnsworth is one of eight CO_2-EOR units in Oklahoma and Texas operated by Chaparral Energy with each using 100 percent anthropogenic CO_2.



Map of Farnsworth Unit showing production and injection wells. CO_2-EOR began in the western-most side in 2010 and is progressing eastward.

Background image: Pumpjack and sunset at the Farnsworth Unit, Texas.

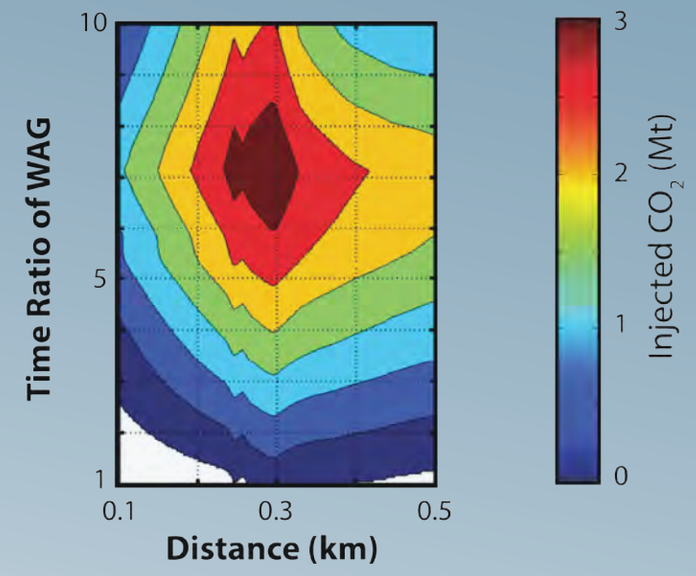
Risk Assessment

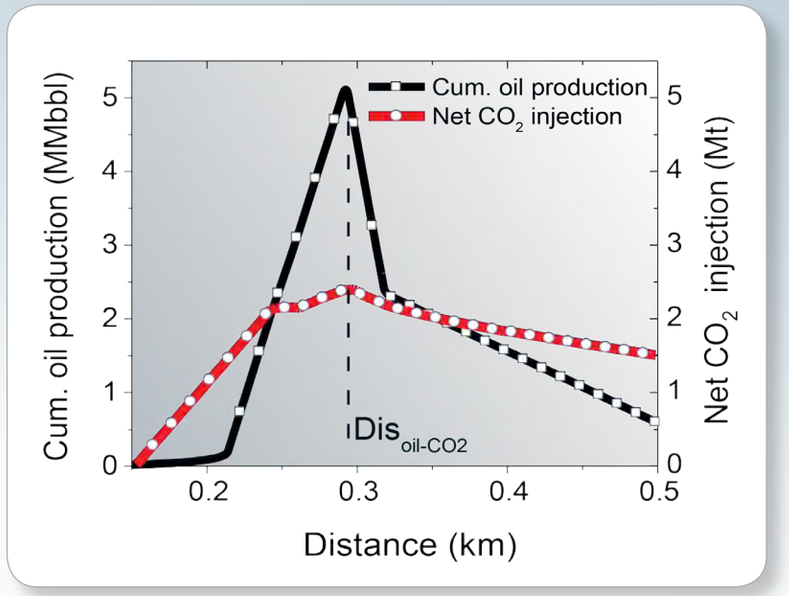
The risk assessment program for the Farnsworth Unit project focuses on two primary aspects: (1) programmatic risks, including resource and management risks, which may impede project progress or costs and (2) CO_2 storage (technical) risks inherent to the scientific and engineering objectives of the project. The SWP project team tracks both programmatic and CO_2 storage (technical) risks and develops risk mitigation approaches in a continuous and iterative manner.

The SWP risk assessment has six primary tasks:

- Risk Management Planning
- Risk Identification
- Qualitative Risk Analysis: SWP categorizes risks by cause and impacts and identifies those that require response in the near term
- Quantitative Risk Analysis: SWP quantifies critical elements, defines scenarios for each risk, and conducts probabilistic risk assessment
- Risk Response Planning: SWP develops a risk avoidance plan, risk transfer strategy, and/or risk mitigation plan
- Risk Monitoring and Control: SWP keeps track of existing and new risks to evaluate the efficacy of the risk response plan effort

CO_2-EOR at the Farnsworth Unit uses water-alternating-gas (WAG) cycles to control CO_2 mobility and CO_2 flood conformance and to tackle the clogging and scale issues in the partially depleted Morrow reservoir. The SWP identified a set of independent parameters and/or dependent risk factors for assessing the operational and technical risks at the Farnsworth Unit. An integrated simulation of CO_2–water-oil flow and reactive transport is conducted, followed by a global sensitivity and response surface analysis, for optimizing the CO_2-EOR operational parameters. The results indicate that the reservoir permeability, porosity, thickness, and depth are the major intrinsic reservoir parameters that control net CO_2 injection/storage and oil/gas recovery rates. The distance between injection and production wells and the sequence of alternating CO_2 and water injection are the significant operational parameters for designing a five-spot CO_2-EOR pattern that efficiently produces oil while storing CO_2. The results from this analysis provide useful insights for understanding the potential as well as uncertainty for commercial-scale CO_2 storage incorporating a utilization component.





Determining the operational parameters with response surface analysis; here, maximizing oil production based on WAG ratio (graph above), and determining the optimal distance between the injection and production wells (graph below).

Public Outreach, Knowledge Sharing/Dissemination

The SWP outreach efforts strive to provide information on CCS for project stakeholders and to the public at large. The SWP's outreach efforts are comprised of the project website, project publications, and various educational undertakings.

The SWP has sponsored or participated in a number of educational activities, including college level courses, short courses designed for K-12 science teachers, and field classes. Partnership members participate at local and regional meetings and provide expertise and information to industry, trade associations, and other interested organizations. Outreach efforts also include information given to stakeholders about the technical benefits of CO_2 site characterization, modeling, injection, and monitoring.

Project stakeholders include private industry, non-government organizations (NGOs), the general public, and government entities.

As part of SWP outreach efforts, stakeholders are informed of the following technical benefits of CCS:

- Increased resolution of reservoir characterization
- Direct and frequent sampling and fluid analyses
- Collection of core and detailed logging suites
- Petrophysical, geochemical and geomechanical core testing
- Optimization of CCS methods through monitoring and simulation

For more information about SWP, please visit:
http://southwestcarbonpartnership.org/

Redesigned SWP website: www.southwestcarbonpartnership.org

Background image: VSP survey being conducted by Schlumberger Q-Borehole Explorer vibrator truck at the Farnsworth Unit.

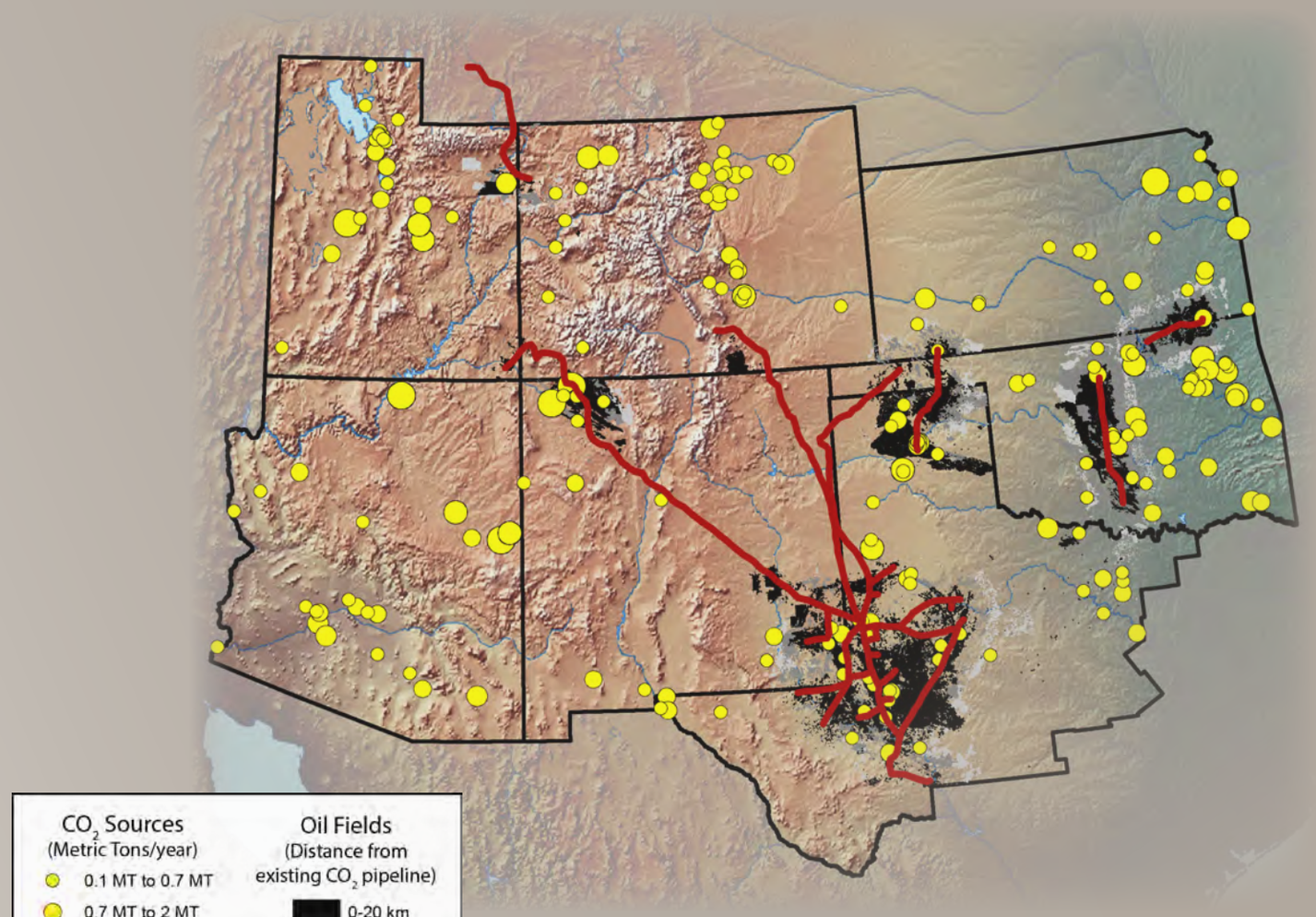
Commercialization of CCS in the SWP Region

The SWP Region is in a unique position, both geologically and technically, to take advantage of CCS opportunities. Enhanced oil and gas recovery (EOR/EGR) operations in Texas, Oklahoma, Colorado, New Mexico, and Utah currently utilize a pipeline network to deliver predominantly naturally-sourced CO_2 to fields.

The existing CO_2 pipeline network is also located near some of the region's largest stationary CO_2 sources, such as the coal-fired power plants of northern New Mexico. Additionally, approximately 20 percent of the region's existing oil fields are within approximately 12.4 miles (20 kilometers) of this pipeline network, representing greater than 25 billion metric tons of potential CO_2 storage capacity. The potential impact on the economy is tremendous. For example, one of the smaller oil producing states in the SWP region is Utah, and for Utah alone, the estimated increase in oil production by CO_2-EOR is approximately 2 to 20 million barrels per year. At $80 per barrel this translates to approximately $160 million to $1.6 billion annually; even at $50 per barrel, CO_2-EOR would yield an additional approximately $100 million to $1 billion annually for Utah.

Beyond enhanced oil production, other potential commercial technologies include:

- Advanced enhanced oil recovery technologies (e.g., CO_2 mobility technologies [foams, gels, etc.])
- Advanced coalbed methane recovery technologies
- Advanced seismic imaging technologies (e.g., optimization of tomographic methodologies)
- Advanced chemical sensor technologies (e.g., for high pressure and temperature conditions)
- Catalysts for rapid "mineralization" of CO_2 with appropriate cations
- Advanced membrane technologies, including membranes for separation of CO_2 from flue gasses and membranes for desalination of produced brines



SWP region oilfields within favorable distance of existing CO_2 pipelines.

ILLINOIS BASIN–DECATUR PROJECT

Introduction

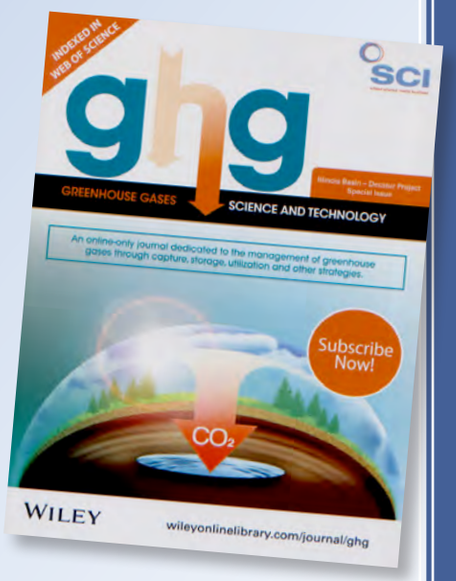
The Midwest Geological Sequestration Consortium's (MGSC) Illinois Basin–Decatur Project (IBDP) is a collaboration of the MGSC, the Archer Daniels Midland Company (ADM), Schlumberger Carbon Services, and other subcontractors to inject 1 million metric tons of anthropogenic carbon dioxide (CO_2) into a saline reservoir, the Mt. Simon Sandstone, in Decatur, Illinois. Operational injection started on November 17, 2011, and was completed in November 2014. The objectives of the project are to validate the capacity, injectivity, and containment of the Mt. Simon Sandstone, which represents the primary CO_2 storage resource in the Illinois Basin and the Midwest Region.

The Mt. Simon Sandstone is more than 1,500 feet (457 meters) thick at the site. The upper portion was deposited in a tidally influenced system, while the lower 600 feet (183 meters) is an arkosic sandstone that was deposited in a braided river/alluvial fan system. The lower Mt. Simon Sandstone is the principal target for storage, in part because the dissolution of feldspar grains has created good secondary porosity. The Eau Claire Formation is the primary confining layer, or seal, and is 695 feet (212 meters) thick. The Lower Eau Claire consists of shale and the Upper unit consists of low-permeability limestone and siltstone.

The IBDP is an integrated industrial CCS system from source to reservoir. The project uses CO_2 from ADM's ethanol fermentation plant. Operations consist of a compression/dehydration facility, a delivery pipeline, one injection well, one deep observation/verification well, and a geophysical test well, all developed on the ADM-owned site. A full subsurface and surface monitoring, verification, accounting (MVA), and assessment program is in place and periodic data collection, such as fluid sampling, geophysical measurements, and cased-hole logging, is ongoing. Core and log data from the original drilling operations are being integrated with a 3-D seismic volume to further interpret original depositional systems and support reservoir simulation.

Location of the IBDP.

Background image: View looking north at the IBDP injection well and CO_2 pipeline with drilling rig for the verification well in the background.



Special Wiley publication (October 2014) focused on the IBDP.

PROJECT HIGHLIGHTS INCLUDE:

- Operational CO_2 injection began on November 17, 2011, at a nominal rate of 1,000 metric tons per day. After 3 years of operations, the injection goal was met in November 2014. Capacity, injectivity, and containment potential have met and/or exceeded pre-injection expectations.
- Development and implementation of a rigorous and extensive MVA program, including 3-D seismic, 3-D vertical seismic profile (VSP), soil flux monitoring, atmospheric monitoring, shallow groundwater monitoring, and deep subsurface monitoring and fluid sampling. Data collection covering 18 months of pre-injection baseline, 36 months of operational injection, and up to 10 years of post-injection monitoring.
- Design and construction of a compression/dehydration/pipeline facility that processes wet CO_2 at atmospheric pressure from ethanol fermentation units into dry supercritical CO_2 and delivering it to the wellhead.

Site Characterization

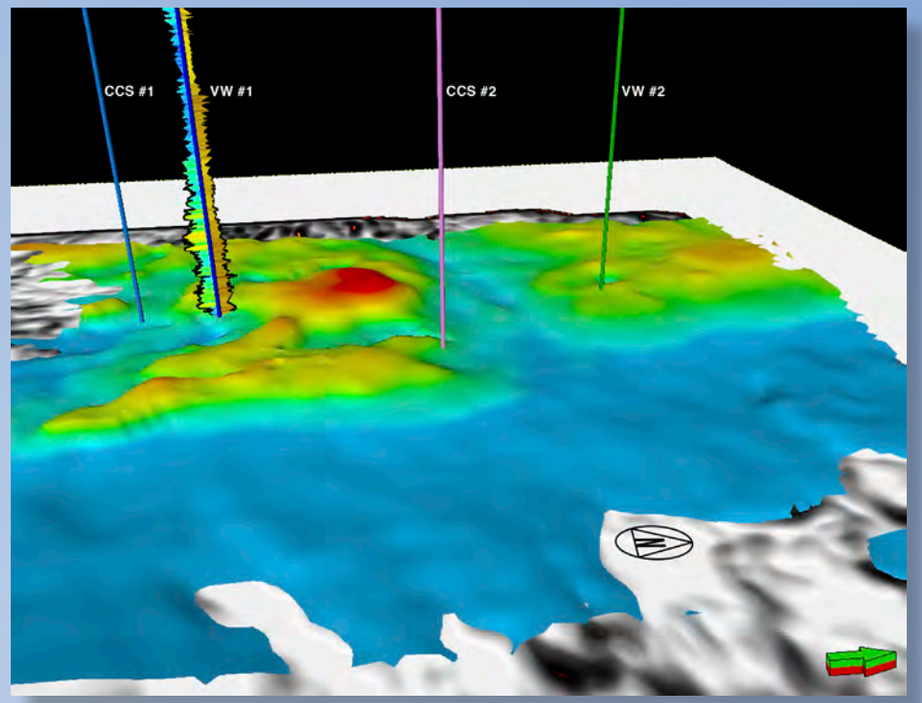
Beginning in 2003, MGSC undertook a comprehensive study of the Illinois Basin CO_2 storage potential in the search for a reservoir-seal system that provides capacity, injectivity, and containment. The initial regional characterization showed that the Mt. Simon Sandstone offered sufficient depth, thickness, and porosity to contain CO_2 and the overlying rock unit, the Eau Claire Formation, provided the necessary seal for safe and effective long-term storage.

Within the Illinois Basin, three thick shale units function as major regional seals. The lowermost and primary seal, the Eau Claire, has no known penetrations within a 17-mile radius surrounding the IBDP site. All three major seals are laterally extensive and appear, from subsurface wireline correlations, to be continuous within a 100-mile (185.2 kilometers) radius of the test site. There are no mapped regional faults or fractures within a 25-mile (40 kilometers) radius of the proposed site. 2-D and 3-D seismic reflection data were acquired near the site to identify the presence of faults and geologic structures in the vicinity of the injection well site. No seismically resolvable faults or fracture indicators were seen on those data.

Approximately 21 wells have been drilled into the Mt. Simon (greater than 4,500 feet [1,372 meters] measured depth) in central and southern Illinois. Many of these wells penetrated the top few hundred feet or less of the Mt. Simon. Ten Mt. Simon gas storage projects show that the upper 200 feet (61 meters) has porosity and permeability high enough to serve as a viable storage target.

Based on the well log, seismic volumes, and core analyses, and interpretation of the injection and verification wells, the Mt. Simon and Eau Claire have been thoroughly characterized at the IBDP site. Between the injection and verification wells, approximately 700 feet of whole core and more than 125 sidewall rotary core samples were acquired. A short-term pressure transient test was conducted to confirm the core-log permeability transform. The IBDP injection was targeted in the deepest part of the 1,506 feet-thick (459 meters) Mt. Simon, in the intervals of 7,025 to 7,050 feet (2,141 to 2,149 meters) and 6,985 to 7,015 feet (2,129 to 2,138 meters). The porosity is in the range of 18 to 25 percent and the permeability is in the range of 40 to 380 millidarcy (mD) over both intervals.

The spatial representation of the detailed characterization at each well bore included 2-D, 3-D, and VSP seismic data to improve the characterization between wells. This data serves as the basis for several geostatistically generated geologic site models. The 3-D surface data has shown internal reservoir depositional heterogeneity, such as channel forms within the Mt. Simon. A repeat 3-D VSP run in March 2012 with approximately 70,000 metric tons injected was not successful in defining an injected plume. A second monitoring survey in April 2013 with approximately 470,000 metric tons injected defined changes associated with a plume developed to the north-northwest of the injection well. Repeat 3-D VSP will continue to be used to monitor the position of the plume within the reservoir. Site characterization was conducted throughout the injection period (ending Fall 2014) and will continue through the post-injection monitoring period (through Fall 2017).



Visualization of Mt. Simon Sandstone paleotopography using 3-D seismic reflection showing potential channel between wells CCS2 and VW2.

Background image: 3-D seismic data acquisition in April 2013.

Risk Assessment, Simulation, and Modeling

The IBDP risk mitigation process has two objectives: (1) to ensure that risks are identified and (2) to ensure that all identified risks are reduced and/or held to acceptable levels. The IBDP risk assessment process considered the potential impact to five specified project values, including health and safety, financial, environment, research, and advancing the viability and public acceptability of geologic storage. Some of the technical risks addressed included potential limitation of the deep well sampling system due to corrosion and interference of nearby surface traffic (e.g., trains, trucks) on seismic surface sensors at the IBDP site. Non-technical risks addressed were communication challenges, such as misinformation, inconsistent data or presentations, and public communication strategies. To mitigate these non-technical risks, a revised communications plan was developed along with new fact sheets and project information to explain project activities.

IBDP reservoir modeling activities have focused on the integration of 3-D seismic data and new borehole data with the objective of developing the capability to perform consistent reservoir engineering and mechanical forecasting within a representative geological context. The results are used to investigate pressure, saturation, and mechanical behavior for selected injection operational forecasting scenarios. The modeling workflow is applied as a sequence of distinct, but interrelated, modeling steps:

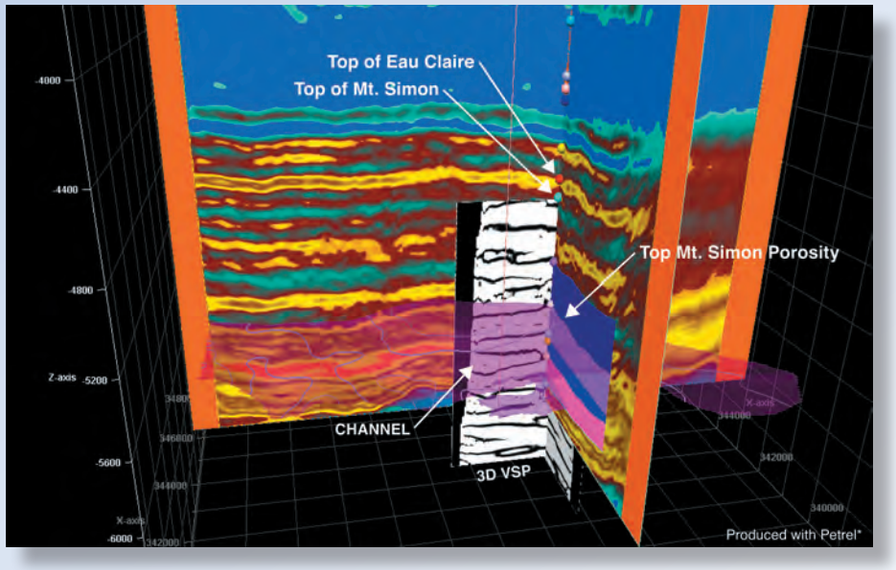
- *Geologic Model*—This initial step has two main components: (1) defining the structural/stratigraphic framework and (2) populating the model with porosity and permeability for reservoir simulation. Both of these components rely on the quantitative integration of 3-D seismic data with well logs.

- *Reservoir Engineering Model*—In this step, the reservoir model is used to perform forecasts of pressure and saturation for given future injection operational scenarios.

- *Geomechanical Modeling*—The mechanical modeling workflow has two steps: (1) the integration of available geomechanical data to create the mechanical earth model (MEM) and (2) the use of the MEM as input to a dynamic geomechanical simulator (Visage*) for forecasting. Preliminary simulations have been performed to project stress paths at selected locations in the wellbore and reservoir for hypothetical injection scenarios.

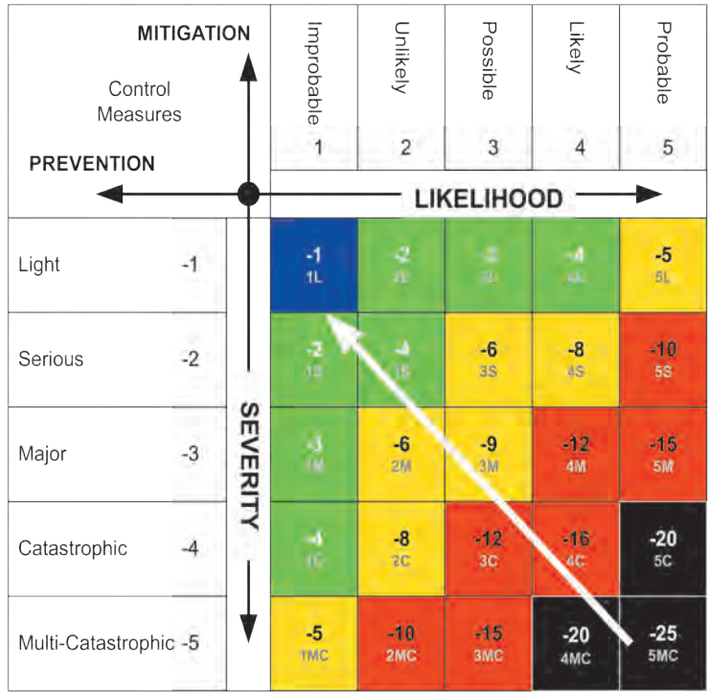
Another component of the modeling effort addresses the basin-scale impacts of storage in the Mt. Simon. The goal of this component is to predict brine migration and reservoir pressure increases that could result from future, commercial-scale, geologic CO_2 storage. A basin-scale, multi-phase flow model of the Mt. Simon for the Illinois Basin has been developed. The model covers most of Illinois and Indiana and allows for modeling pressure increases in the Mt. Simon and Eau Claire resulting from industrial-scale geologic CO_2 storage. The model includes structural or stratigraphic, capillary, and solubility trapping used to study the long term behavior of CO_2. Models will be used to guide future data collection efforts and design monitoring strategies.

* Mark of Schlumberger



Visualization of porosity distribution in Mt. Simon Sandstone using 3-D seismic inversion methodologies.

-25 to -20	BLACK	NON-OPERABLE: Evacuate the zone and or area/country
-16 to -10	RED	INTOLERABLE: Do not take this risk
-9 to -5	YELLOW	UNDESIRABLE: Demonstrate ALARP before proceeding
-4 to -2	GREEN	ACCEPTABLE: Proceed carefully, with continuous improvement
-1	BLUE	NEGLIGIBLE: Safe to proceed



Hypothetical elements of risk are located on a grid, scaled in terms of relative likelihood and severity. Image courtesy of Schlumberger Carbon Services.

Monitoring, Verification, Accounting, and Assessment

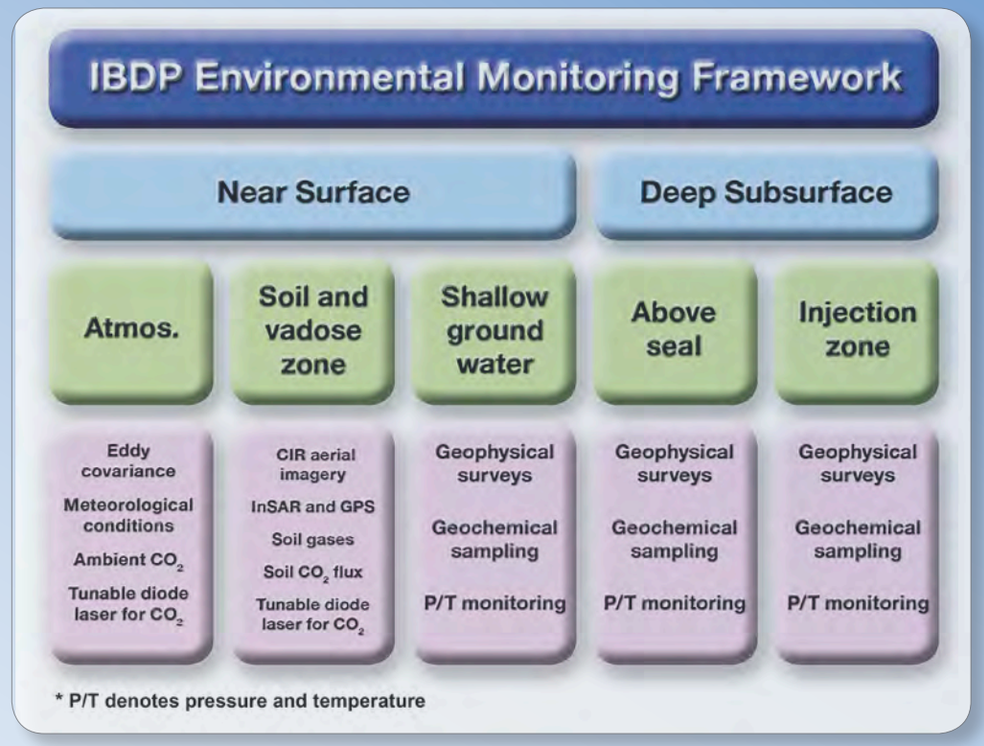
MGSC has undertaken an extensive MVA program for the IBDP that involves environmental measurements, monitoring, and computer modeling focused on the 0.25 mi^2 (0.65 km^2) site throughout the life of the project. Near-surface and subsurface monitoring are integral efforts to reach MVA and project goals, including: (1) establishing pre-injection environmental conditions to evaluate potential impacts from CO_2 injection, (2) demonstrating that project activities are protective of human health and the environment, and (3) quantifying and tracking CO_2 stored in the Mt. Simon during and after injection operations.

Research monitoring was initiated in 2009, allowing up to 24 months of pre-injection baseline data, and will conclude in 2017 after the 3-year post-injection period. A post-injection site care monitoring period will also be undertaken (presently defined for 10 years as stipulated in the IBDP Class VI post-injection UIC permit. The MVA program involves approximately 20 different monitoring methods/technologies. The IBDP site is also being used to develop and field test CO_2 storage-related MVA instrumentation and technology for deployment at future CCS projects in the United States and throughout the world.

The long-term CO_2 storage effectiveness in the Mt. Simon is being evaluated using pressure monitoring and fluid sampling through an in-zone verification well designed to monitor the injection formation and formations immediately above the primary caprock. A dedicated geophone well facilitates repeat seismic imaging over the life of the project. Subsurface monitoring efforts include 2-D seismic surveying; 3-D seismic and VSPs; passive microseismic monitoring; injection zone temperature, pressure, and fluid monitoring; above-caprock temperature, pressure, and fluid monitoring; and open- and cased-hole logging.

Monitoring of the near-surface environment includes color aerial imagery, interferometric synthetic aperture radar (InSAR), shallow groundwater quality, soil CO_2 fluxes, net exchange CO_2 fluxes, and vadose zone CO_2 concentrations. Environmental monitoring data through the end of the injection period have shown no signs of CO_2 release and have helped demonstrate that the project protects human health and the environment.

The MVA program is a coordinated effort among the Illinois State Geological Survey (ISGS), Schlumberger Carbon Services, ADM, Lawrence Berkeley National Laboratory (LBNL), University of Illinois, TRE-Canada and the Carbon Capture Project, Physical Sciences Incorporated, Illinois Department of Transportation, and others.



Generalized environmental monitoring framework at the IBDP site.

Background image: Shallow groundwater sampling.

Site Operations

The project site is located at ADM's industrial facility in Decatur, Illinois, a city with a population of 75,000 in 2013. ADM's Decatur complex consists of various processing facilities, including a corn wet milling plant with ethanol production that serves as the CO_2 source for the IBDP. The injection well and verification wells are located in a field north of the industrial facilities. The field was previously used for corn/soybean farming or left fallow.

The IBDP CO_2 source is downstream of product recovery scrubbers that follow the ADM ethanol fermentation units. The CO_2 is greater than 99 percent pure (by volume) and saturated with water vapor at 80 °F and 1.5 pounds per square inch gauge (psig) (10.5 kilopascal gauge [kPag]). Since the CO_2 stream exits the fermentation unit at near ambient conditions, a compression system was required for delivering supercritical CO_2 to the wellhead for injection. A dehydration unit was included in the compression system to reduce the potential for corrosion of the pipeline caused by the presence of the water. One multistage centrifugal blower with one 1,250 horsepower (hp) (632 kilowatt [kW]) motor raises the CO_2 pressure to 18 psig (124 kPag). Two four-stage reciprocating compressors operating in parallel, each with 3,250 hp (2.42 megawatt [MW]) motors, raise the CO_2 pressure to approximately 1,400 psig (9.65 megapascal gauge [MPag]). Glycol dehydration after the third stage of compression lowers the water content of CO_2 to approximately 200 parts per million by volume (ppmv), which is less than typical U.S. carbon steel pipeline specifications. The CO_2 is cooled to 95 °F (35 °C) after the blower and each reciprocating compression step using cooling water in shell-and-tube heat exchangers. Surface injection pressures have ranged from 1,300 psig (8.96 MPag) to 1,400 psig (9.65 MPag). One multistage centrifugal pump with one 200 hp (149 kW) motor is available to raise surface pressures as high as 1,950 psig (13.44 MPag) if needed to achieve desired injection rates, but the pump has not been utilized to date. The compression and dehydration system is equipped with automated measurement of critical flow rates, temperatures and pressures, and CO_2-water content and oxygen content. Automated measurements are integrated with the host-site Distributed Control System (DCS) and are interlocked for automated shutdown as needed to ensure safe operation and to prevent equipment damage.

The above-ground pipeline from the compression site to the injection site is 6-inch (152 millimeter) nominal diameter Schedule 40 carbon steel pipe and is approximately 6,400 feet (1,951 meters) long. The pipeline was insulated following injection startup to minimize weather-related temperature swings that led to system shutdowns. Based on the anticipated Mt. Simon net thickness and permeability that were confirmed by drilling, reservoir modeling and nodal analyses suggested that a single injection well with 9⅝-inch diameter injection casing and 4½-inch diameter injection tubing would meet the 1,000 metric ton per day target injection rate. These assessments have been validated by the successful injection of 1 million metric tons of CO_2.

Aerial image of the IBDP site (CO_2 pipeline shown in blue).

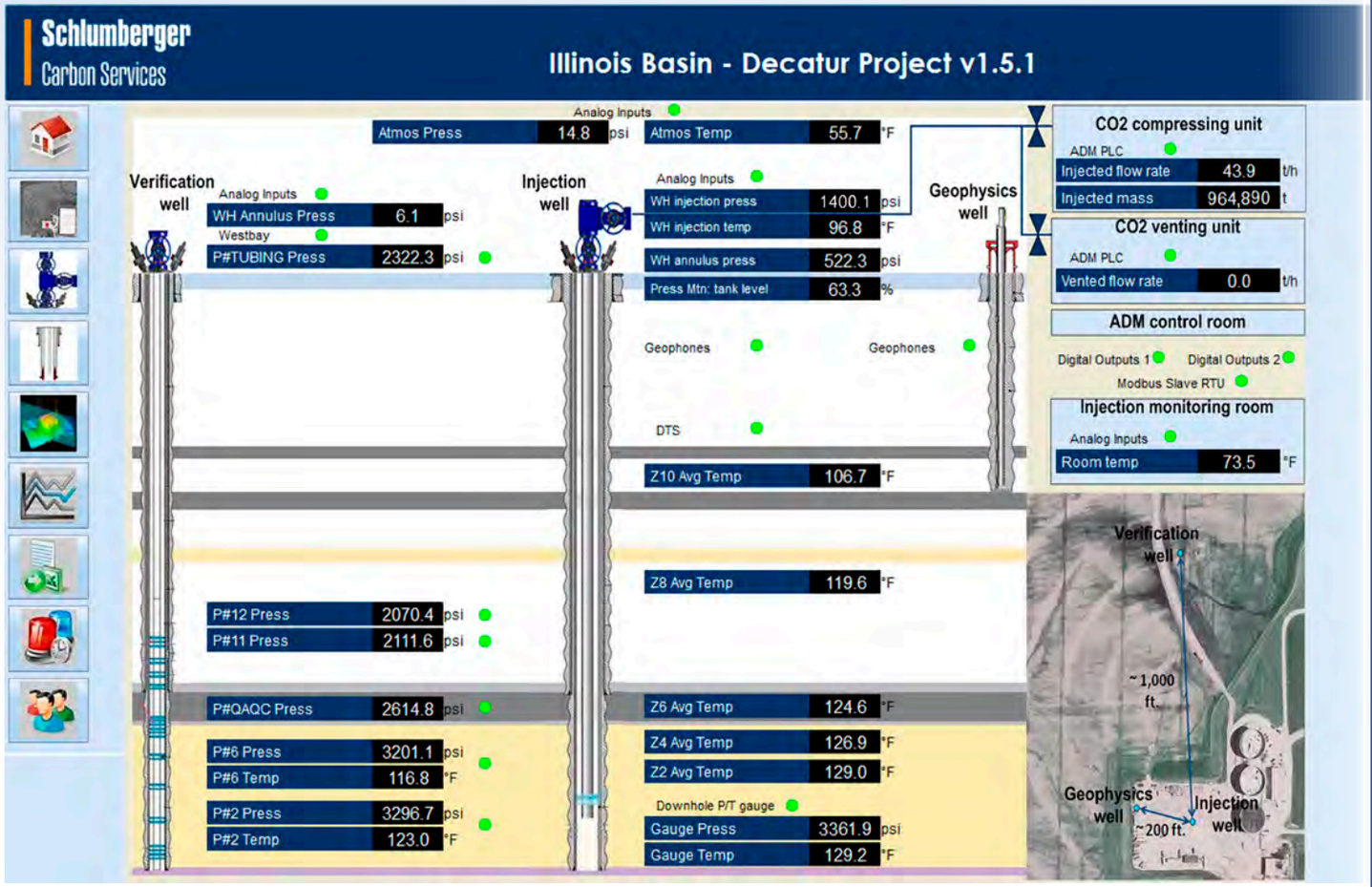
Background image: Lubrication of IBDP injection well before logging.

Site Operations (cont'd)

Optimizing CO_2 storage operations for both efficiency and safety requires the deployment of monitoring sensors and implementation of control protocols. For that purpose, permanent and temporary monitoring techniques were deployed at the IBDP to collect data, which will be managed and integrated for interpretation at different time scales.

Site operations are administered through the real-time acquisition and control (RTAC*) software. This real-time monitoring provides increased operational safety, as RTAC collects vast amounts of data on a high frequency basis and provides a secure Internet site for project personnel to access real-time information on injection operations and downhole conditions in the observation well, the injection well, and the geophone-equipped seismic monitoring well. A fast data interpretation loop involves combining continuous measurements as they are collected to enable a rapid response to detected events. A slower interpretation loop combines large data sets and is performed at an expert level.

RTAC is fully integrated with the ADM control room for the CO_2 compression/dehydration facility. RTAC provides continuous subsurface project data, such as wellhead pressure and temperature, downhole pressure and temperature, and annulus pressure, which is critical to operational monitoring. This data is recorded, archived, and continuously accessible. The software records and formats pressure, temperature, annulus pressure, and injected volumes as required for reporting to the Illinois EPA. RTAC generates approximately 2.5 gigabytes of data per month. A digital temperature system (DTS) also adds borehole temperature recorded from a fiber optic cable strapped to the tubing string from surface to packer. This system obtains an additional 1.4 gigabytes of data per month.



Screen shot of the RTAC display. Image courtesy of Schlumberger Carbon Services.

IBDP PROJECT OPERATIONS SUMMARY

Permitted Injection Volume: 1 million metric tons of CO_2

Target Reservoir: Mt. Simon Sandstone

Depth of Reservoir Top: 5,545 feet (1,690.5 meters)

Thickness of Reservoir: 1,506 feet (459.1 meters)

Reservoir Seal: Eau Claire Shale

Depth to Seal Top: 5,047 feet (1,538.7 meters)

Injection Rate: 1,000 metric tons per day

Injection Duration: November 2011 to November 2014

CO_2 Source: Fermentation for ethanol production

Compression Equipment: Dual four-stage reciprocating with glycol dehydration

Wellhead Injection Pressure: 1,350 psi (9.3 MPa)

Wellhead Injection Temperature: 95° F (35° C)

Delivery Pipeline: 6-inch (15.24 cm) carbon steel, 1.2 mile (1.9 kilometers) length

Depth of Injection Interval: 6,985–7,050 feet (2,129.6–2,149.4 meters)

* Mark of Schlumberger

Public Outreach, Knowledge Sharing/ Dissemination

The MGSC views public engagement as an opportunity to provide fact-based education and outreach material to engage stakeholders in issues surrounding CCS. With this objective in mind, public outreach and knowledge sharing have remained a priority for MGSC since its inception in 2003. MGSC contributed to and follows the principles defined in NETL's Public Outreach and Education for Carbon Storage Projects Best Practices Manual, specifically the integration of outreach into project management. To help build informed and supportive constituencies, MGSC outreach activities have engaged local, regional, and international stakeholders through print and online materials, open houses, presentations, model demonstrations, school visits, curriculum development, teacher professional development, stakeholder meetings, invited briefings, public hearings, short courses, workshops, and conferences.

The MGSC outreach effort was formalized with the development of the Sequestration Training and Education Program (STEP) in 2009. STEP received additional DOE funding to (1) facilitate knowledge sharing and capacity building gained through leadership and participation in regional carbon storage projects and (2) provide local, national, and international education and training opportunities for those interested in CCS technology. All MGSC outreach, communication, knowledge sharing, and capacity building efforts have benefited from this centralized approach, which allows for greater impact, scope, and reach.

A variety of outreach materials, including fact sheets, brochures, posters, presentations, websites, rock kits, and models, have been utilized to provide information about the IBDP and CCS to major stakeholders in the Decatur area and the general public. Project partners have also established working relationships with local media and use this outlet to enhance community engagement in the project. MGSC also regularly engages in domestic and international collaborative initiatives through technology transfer and capacity building to share project details and promote CCS technology.

For more information, please contact:
Sallie Greenberg, Ph.D., Associate Director, AETI, Illinois State Geological Survey, 217-244-4068

As the science and technology of CCS evolves, the methods and strategies of outreach and engagement become more refined. The following list details the lessons learned during this project that can serve as a framework for future projects:

- Dedicate resources to engagement (e.g., people, time, and budget)
- Understand the community and citizens living in the project area
- Evaluate and reevaluate message, progress, needs and resources on a continual basis
- Coordinate and plan with all project partners
- Value local voice and, when possible, use a local voice for local projects
- Develop and use a communications plan
- Integrate risk assessment results into project management and communications strategy
- Identify and engage stakeholders in multiple venues, multiple times
- Conduct an ongoing media analysis
- Catalog questions asked and create acceptable/approved answers for repeated questions
- Be prepared for public meetings; know what is important to stakeholders
- Plan events for community and stakeholder benefit with respect to timing, nature, and impact
- Seek and engage in knowledge-sharing opportunities

(Above) Second Korea CCS Conference, February 2013.

(Right) Site presentation for Chinese delegation from the World Bank, May 2013.

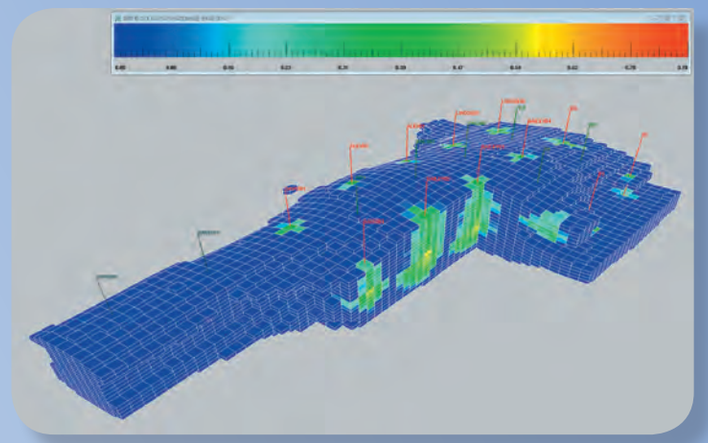
Commercialization of CCS in the MGSC Region

The goal of the IBDP is to demonstrate the potential of the Mt. Simon Sandstone as a geologic CO_2 storage reservoir for the Illinois Basin region. The Illinois Basin region covers most of Illinois, southwestern Indiana, and western Kentucky. The IBDP is designed to demonstrate a pathway for commercial usage of the Mt. Simon Sandstone CO_2 storage resource.

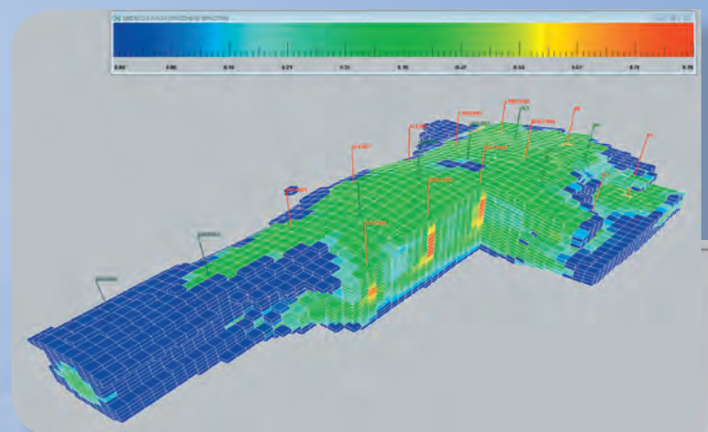
The key research targets for MGSC's large-scale injection test relate to CO_2 injectivity and volumetric storage capacity of the saline reservoir; the integrity of the seals to contain the CO_2 in the subsurface; and the entire process of pre-injection characterization, injection process monitoring, and post-injection monitoring to understand the fate of the injected CO_2. While the IBDP has a defined duration, there may be future interest in commercializing this storage site with continued injection into this well beyond the injection permit period via permit extensions. The potential volumes that may be stored in the Mt. Simon have been assessed at 12 billion to 172 billion metric tons of CO_2, making this formation desirable for future CCS projects.

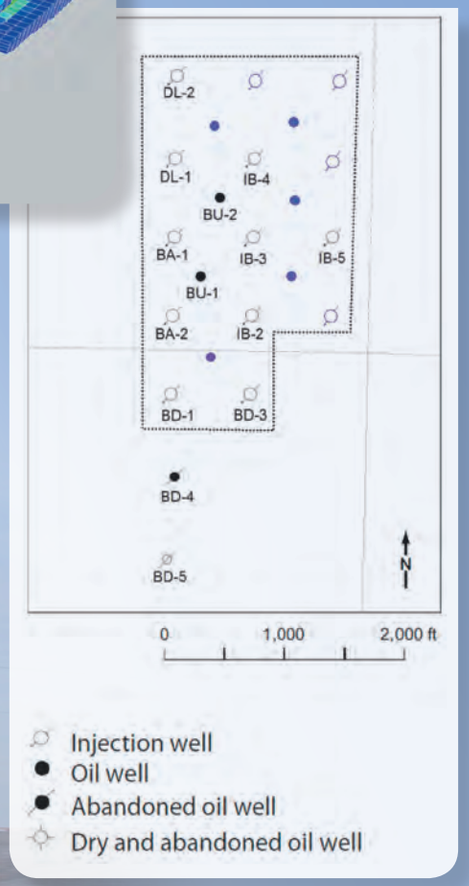
The IBDP has served as a tool for defining a larger project, the Illinois Industrial Carbon Capture and Storage (ICCS) project. The ICCS is a 5-year industrial CO_2 storage project funded by DOE. While the IBDP has reached its goal of 1 million metric tons injected, the ICCS will increase the annual volume of CO_2 stored and capture CO_2 from the ADM ethanol production facility at a rate of approximately 1,600 metric tons/day. The ICCS project involves the same project team members as IBDP with the inclusion of Richland Community College, which hosts the National Sequestration Education Center. In November 2014, the ICCS project was granted a Class VI permit to drill an injection well approximately three-quarters of a mile northeast of the IBDP injector. The ICCS well is designed to take nearly 2.5 million metric tons of CO_2 over a multiyear injection period. MGSC was issued a post-injection monitoring Class VI permit to replace the Class I permit it held for the IBDP injection well. The Class VI Permit for IBDP well CCS1 was effective February 12, 2015. Permitting necessitated the development of a reservoir simulation of dual plumes in the lower Mt. Simon Sandstone to assess plume interaction and define an Area of Review for as much as 3.5 million metric tons injected. This unique application of IBDP results resembles the multi-well injection field that will be required to store CO_2 from commercial power plant sources.

In addition to large-scale storage in saline reservoirs, CO_2-enhanced oil recovery (EOR) may be a viable option to aid CO_2 mitigation strategies in the region while also providing an economic benefit. Detailed oilfield studies are being carried-out along with in-depth examination of capital and operating costs of surface facilities. The studies represent an important step in improving the methodology to estimate CO_2-EOR and storage in oil reservoirs and work toward the commercialization of CO_2-EOR operations in the Illinois Basin.



The Mumford Hills injection simulation shows CO_2 saturation distribution after 1 year (above) and 10 years (below). A total of 9,260 MMscf of CO_2 was injected at year 10.





Reservoir model evaluation area for Mumford Hills oilfield, Indiana, showing proposed additional wells in blue (right).

Background image: Cementing the verification well at the ICCS site.

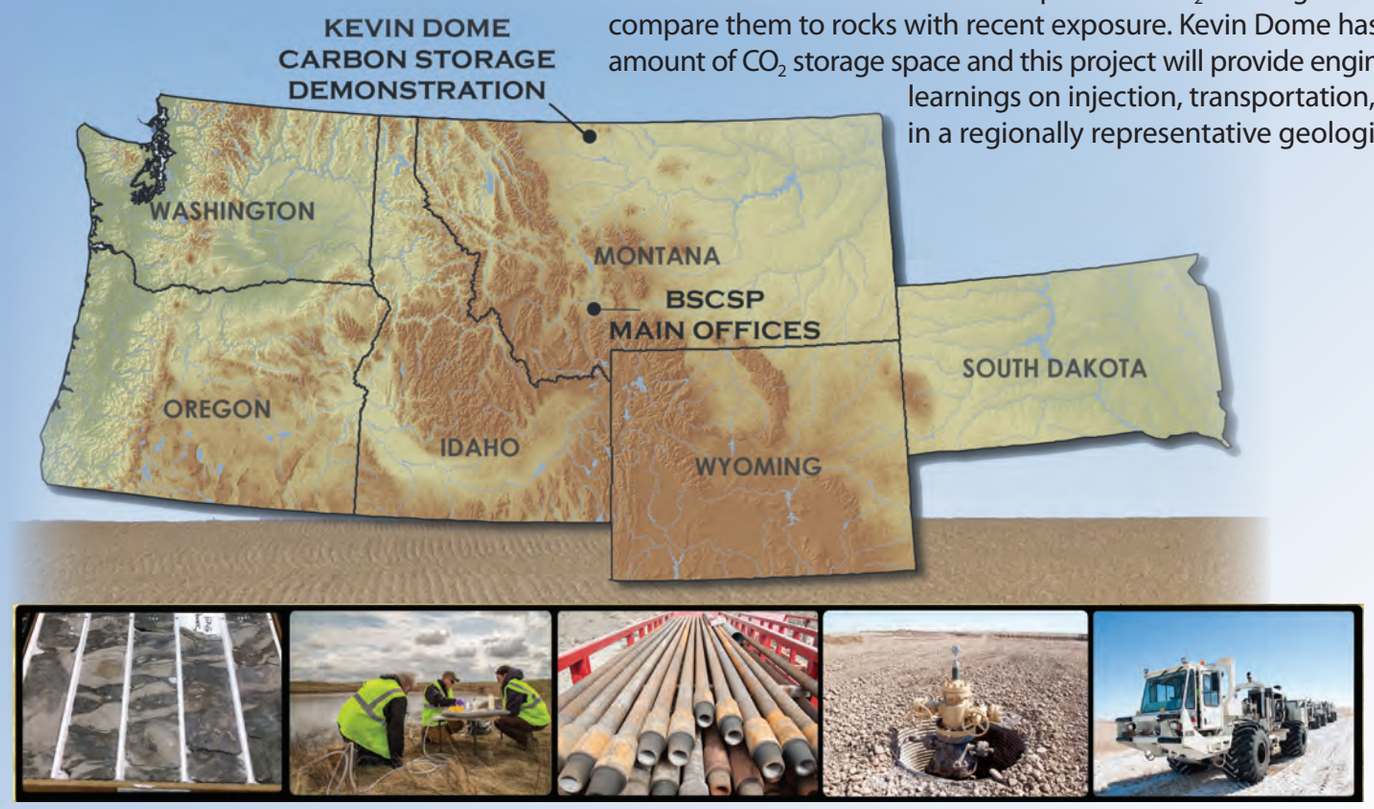
KEVIN DOME PROJECT

BIG SKY CARBON SEQUESTRATION PARTNERSHIP

Introduction

The Big Sky Carbon Sequestration Partnership (BSCSP) is conducting a large-scale field project in north-central Montana to assess carbon dioxide (CO_2) storage potential. Through this study, BSCSP aims to show that a geologic structure known as Kevin Dome in Toole County, Montana, is a safe and viable site to permanently store CO_2. The dome covers more than 750 square miles and has trapped naturally occurring CO_2 for millions of years.

The project plans to inject up to 1 million metric tons of CO_2 into the regionally extensive carbonate Duperow Formation. The project infrastructure includes drilling 2 characterization wells and additional wells for CO_2 injection and monitoring. All wells will have a comprehensive logging program, three wells will be cored, and a state-of-the-art surface seismic program will be conducted as part of the site characterization and monitoring. The CO_2 will be injected into porous rocks located in the middle Duperow that are overlain by two seals. The caprocks include approximately 200 feet of tight carbonates with interbedded anhydrites in the upper Duperow and another 150 feet of anhydrite in the Potlatch Formation. Additional proven seals are at shallower depths that have historically trapped oil and gas. The geologic setting of the Duperow Formation is an ideal site to demonstrate carbon storage because it has proven seal and trap integrity over geologic time. This project will also use Kevin Dome as a natural analog to study geochemical effects on rocks that have been exposed to CO_2 for long time periods and compare them to rocks with recent exposure. Kevin Dome has a significant amount of CO_2 storage space and this project will provide engineered system learnings on injection, transportation, and capacity in a regionally representative geologic setting.



PROJECT HIGHLIGHTS

- Completion of National Environmental Policy Act (NEPA) review and Environmental Assessment with a Finding of No Significant Impacts.
- Site characterization, including:
  - Assimilation and analysis of existing surface and subsurface data and incorporation into the Kevin Dome Atlas and database
  - Creation of an initial static geologic model
  - Completion of preliminary flow models
  - Acquisition of more than 37 square miles of 9-component, 3-D seismic data
  - Completion of BSCSP's first two wells. Core was acquired and analyzed, and a comprehensive log suite was collected from both wells
- Development of a comprehensive risk assessment and risk analysis program
- Implementation of extensive and robust permitting and safety programs, involving local landowners, government agencies, and tribal representatives
- Development of an integrative and interactive data management system
- Acquisition and analysis of baseline data for long-term monitoring activities, including water sampling, soil flux sampling, hyper-spectral flight imaging, LIDAR, and an eddy covariance tower installation
- Multiple community meetings, individual landowner meetings, website, and newsletters

Site Characterization

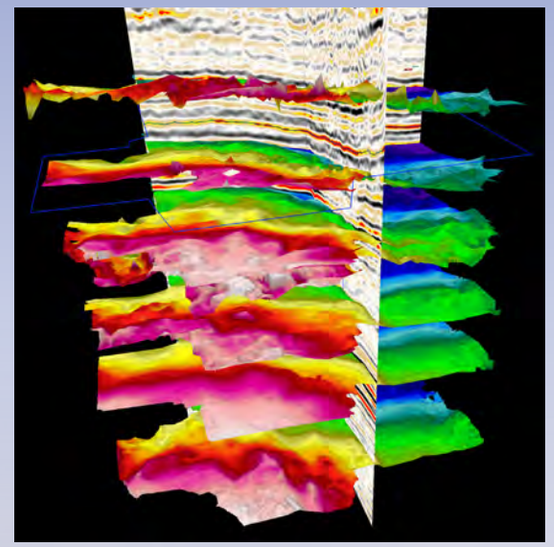
Initial characterization of Kevin Dome focused on understanding the circumstances, continuity, and stability of naturally occurring CO_2 in geologic domes and the potential of domes as large-scale storage sites. A geologic model of the subsurface at Kevin Dome was developed from the data of more than 90 existing wells in north-central Montana. Existing well records provided knowledge of the geologic structure and data on the CO_2 composition, distribution, and volume.

Geologic characterization of Kevin Dome has been used to inform preliminary modelling efforts and to guide site selection for the first two wells drilled in the project area. The wells provide additional geologic and geochemical data that will be incorporated to create an improved subsurface model and describe the injection reservoirs. The data will also provide guidance for future infrastructure development and injection monitoring and modeling.

Surface characterization data has been collected to establish baseline environmental data and to guide decision making for infrastructure development and field research activities. Information on landowners, existing infrastructure, topography, and environmental resources is used in risk assessment, project management, permitting, and research planning. Additional surface characterization includes surface and shallow groundwater sampling and testing, soil flux measurements, hyperspectral imaging, and CO_2 differential absorption LIDAR measurements.

BSCSP has surveyed more than 37 square miles of multicomponent seismic data, including 14 square miles surveyed during the winter of 2014–2015. The seismic data serves several purposes. It is being used to model the subsurface environment, including the location, depth, and thickness of different rock layers and to ensure that no potential release pathways are present. In addition, the advanced, 9-component, 3-D survey has greater sensitivity for CO_2 detection compared to traditional seismic surveys. BSCSP's survey extends over both the natural CO_2 gas cap at Kevin Dome and the brine-filled injection area down the flank of the dome, providing an opportunity to test the ability to detect CO_2 areal extent.

Other characterization activities include the acquisition of a comprehensive suite of log data from the first two characterization wells. The logging data is used to improve site-specific knowledge of the subsurface, including gamma ray, resistivity, density porosity, magnetic resonance, sonic, spectroscopy, and pulsed neutron. Core was also collected from the caprock and reservoir zones of each well and analyzed for porosity, permeability, grain density, bulk density, and saturations. Thin sections were prepared for detailed petrographic description and analysis. A subset of core samples will also be used in core flow experiments with real-time pH and conductivity measurements to determine geochemical reactivity. X-ray CT and magnetic resonance spectroscopy and imaging techniques will be used to measure changes in porosity and permeability as a function of CO_2 flooding. These and additional laboratory analysis techniques will yield hydro-geomechanical and geochemical impacts of CO_2 on carbonate rock. Together, the log and core data are being used to refine the geologic model, refine and test CO_2 plume models, and guide location selection for subsequent wells.



3-D image of the structural surfaces at Kevin Dome selected from shear wave seismic data.

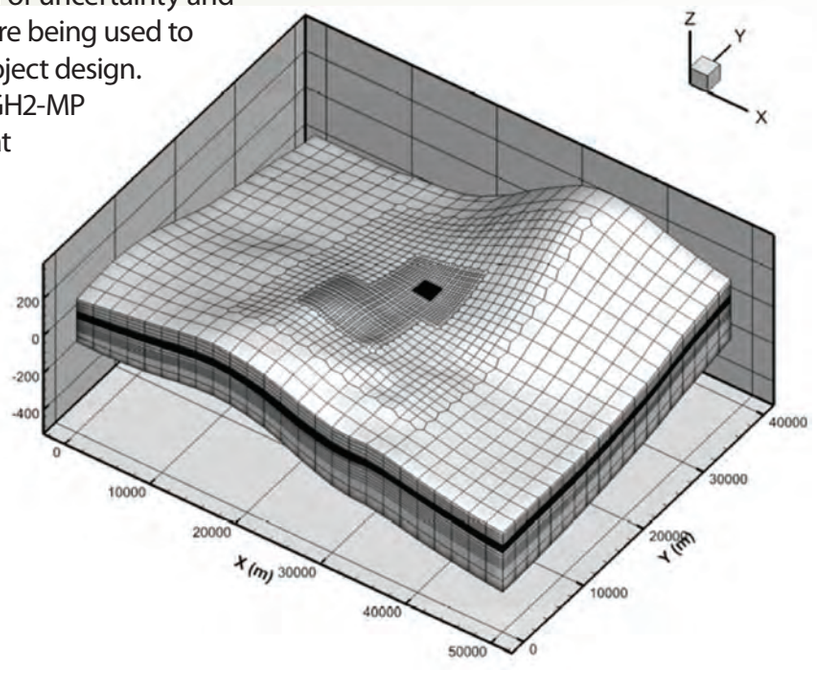
Background image: Vibroseis "thumper" trucks conduct seismic surveys of the underground geophysical environment.

Modeling and Risk Assessment

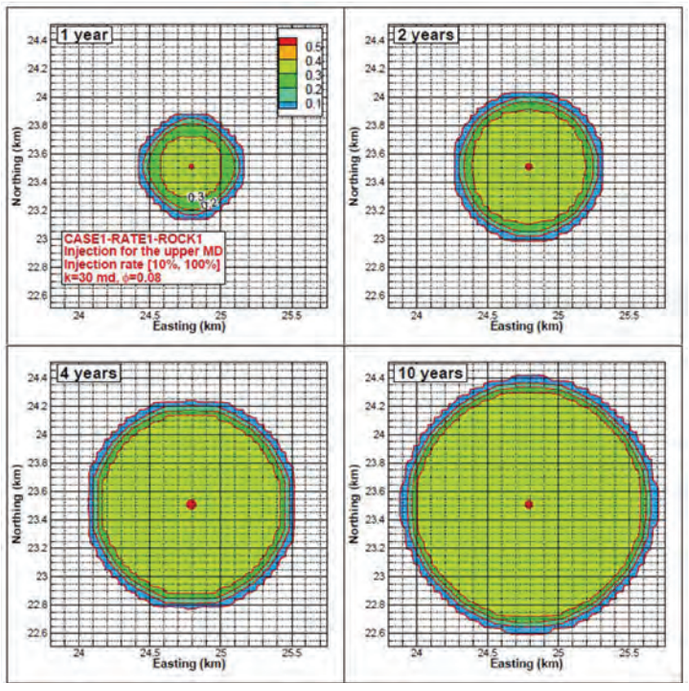
Risk assessment, modeling, and simulation are essential components for assessing feasibility, developing operational plans, facilitating permitting, understanding and quantifying storage processes, and evaluating environmental risks of the Kevin Dome Project. Multiple complementary modeling approaches are being employed, with each focused on improving the understanding of specific project components. The risk assessment and management approach is two pronged. Operational and stakeholder related risks have been identified and ranked through an expert panel process. Treatments for specific risk scenarios have been developed and implemented. The BSCSP team is responsible for identifying emergent risks as new operational phases commence. The top risks identified for Kevin Dome include: driving or workplace accidents; landowner and community perceptions and relationships; project compliance issues; and regulatory uncertainty. Identifying risks related to operational activities allows the team to improve management plans and health and safety procedures to mitigate potential issues before they occur.

Technical risks associated with geologic system performance are being modeled through the CO_2-PENS software platform. This platform allows BSCSP to perform simulations with a range of geologic system properties, such as reservoir permeability, porosity, or pressure conditions, to determine impact on the CO_2 injectivity and producibility. The results of these simulations allow the team to understand the level of uncertainty and build contingency plans, if necessary. Several other models are being used to characterize the geology with greater detail and facilitate project design. A hydrologic multiphase and multicomponent model (TOUGH2-MP with ECO2N) is used to investigate injectivity, pressurization at the well and within the reservoir, and CO_2 movement in the subsurface. The developed model is used to optimize injectivity. Reactive geochemical models (CHILLER and TOUGHREACT) are used to evaluate potential rock reactions, dissolution, or precipitation caused by CO_2 injection into the Duperow dolostone. It is important to understand how injected CO_2 may alter the reservoir rock and change its porosity and permeability over time. Preliminary results indicate that the CO_2 mixture reaches equilibrium with the surrounding rock minerals without significantly changing the rock. Geomechanical performance of the reservoir and caprock will be modeled using TOUGH-FLAC, a simulator capable of modeling multiphase flow coupled to reactive geochemistry and geomechanics.

Lastly, analytical solutions of the CO_2 plume extent and pressure front during and after injection, as well as hypothetical release rates between the CO_2 reservoir and upper formation, are required to determine an area of review. Modeling will be conducted with updated data from laboratory core studies and geochemical and geophysical monitoring activities. The modelling work assists with project planning, site development, permitting, and risk assessment, and to improve the overall understanding of subsurface environment.



3-D mesh with varying gridblock resolutions in the far-field, mid-field, near-field, CO_2 plume, and near-wellbore regions.



Contours of simulated CO_2 saturation in the top model layer of the middle Duperow at 1, 2, and 4 years during the injection period, and at 10 years during the post-injection period.

Monitoring, Verification, Accounting, and Assessment

Monitoring, verification, accounting (MVA), and assessment activities are an important component of the Kevin Dome Project. These activities include a variety of methods that seek to better understand the short- and long-term behavior, injectivity, and storability of CO_2 and to ensure that the project is not impacting the environment or human health.

BSCSP has planned reservoir-zone and above-zone monitoring methods that utilize the innovative technologies developed by project partners. The project will use repeat nine-component, 3-D surface seismic surveys to monitor the CO_2 injection and test state-of-the-art borehole seismic techniques (e.g., crosswell seismic using an orbital source). Natural tracers, such as rare-earth elements and noble gases, will be used to characterize the natural analog in conjunction with phase partitioning tracers to understand the fate of injected CO_2. Borehole monitoring techniques (e.g., U-tube sampling, distributed temperature and pressure sensing, repeat pulsed neutron logging) will be used to provide both reservoir and above injection zone monitoring. Additionally, through collaborative projects, BSCSP and partners plan to perform 4-D resistivity measurements of the CO_2 plume and measure microseismicity and deformation (via InSAR) during injection.

Assurance monitoring techniques have been deployed to gather important background data. Samples of both shallow groundwater and surface water bodies located within the Kevin Dome research area were collected to establish a baseline characterization of the geochemical composition and water quality properties. Future water samples collected post-injection will be compared to baseline measurements to monitor for any changes in geochemistry. Ten shallow water wells and surface water bodies within a 1.5 mile radius of the proposed injection well site were sampled in October 2013, May 2014, and October 2014. The geochemical properties of the water sampled are typical for the conditions prevalent in the Kevin Dome area.

Field crew use a portable soil fluxmeter to measure the amount of CO_2 within the soil located near the proposed injection well site.

BSCSP also made background soil CO_2 flux measurements. A variety of factors influence the CO_2 concentration within soils, including temperature, moisture, microbial activity and variables such as wind and atmospheric pressure. For this study, a survey of soil CO_2 surface flux was made with a portable accumulation chamber. Baseline measurements began in the summer of 2014 in a one-square-mile grid surrounding the proposed injection well site. Results indicated levels of CO_2 flux out of the soil surface that were consistent with what would be expected for soil under this type of land use. To calculate how much CO_2 is exchanged across the ground surface, an eddy covariance tower was installed near the proposed injection site. Background measurements began in June 2014.

Additionally, aerial hyperspectral imaging is being used to monitor for changes in vegetation around the well sites. This type of imaging technique uses the spectra reflected by vegetation to assess plant health, which can be an indirect indicator of elevated CO_2 in the soil. Hyperspectral imaging allows relatively large areas to be surveyed for evidence of plant stress. Point CO_2 detection techniques can then be used to follow up on anomalies seen in the imagery. Baseline imagery, which provides characterization of the spatial variability in vegetation type, density, and distribution, began in the summer of 2014.

Background image: An eddy covariance tower and a weather station were installed in the project area to monitor net CO_2 flux and meteorological variables.

Site Operations

Site operations for the Kevin Dome Project are diverse and include the following phases: project permitting, infrastructure development, CO_2 injection and monitoring, and post-injection activities. The Kevin Dome Project is unique because it is not operating in conjunction with a commercial project or using existing infrastructure. Consequently, project permitting efforts and the planning phase were conducted in a way to ensure that the project operates in compliance with all State and Federal laws and promotes the establishment of long-term relationships with local landowners and nearby communities. To accomplish this, the BSCSP team joined forces with project partners, local companies, and cooperative landowners.

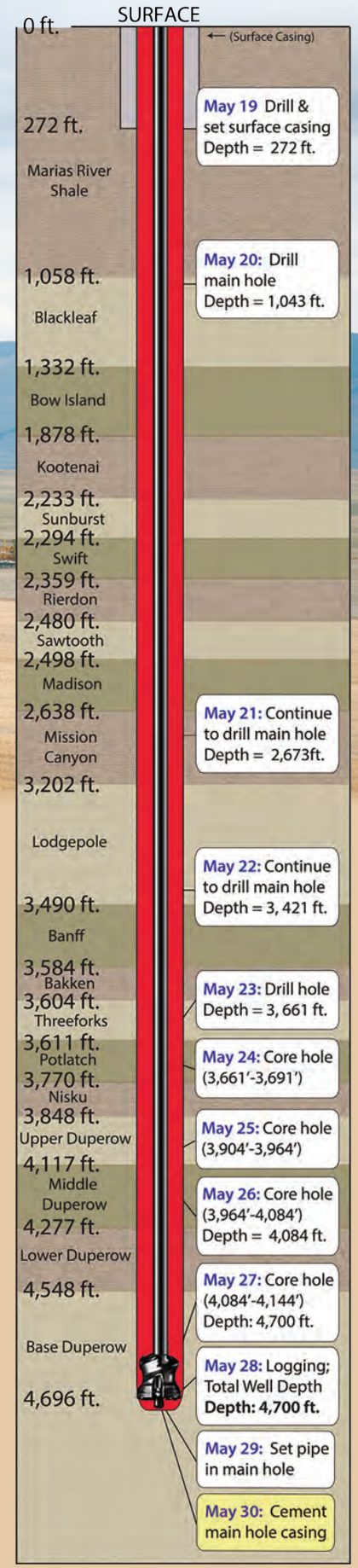
Due to the numerous private, State, and Federal landowners in the project area, the initial permitting phase was extensive. Additionally, there are unique environmental and cultural resources in the project area that the team recognized and remains committed to protecting. This project is also unique because of the wide variety of stakeholders, including several federally recognized tribes in Montana.

The infrastructure development phase includes well site selection and drilling, infrastructure and transportation systems, and ongoing permitting compliance. Two characterization wells have been drilled, with additional wells planned for injection and monitoring. Additional site development will include the construction of a small CO_2 pipeline along with a CO_2-gas gathering system and a CO_2-gas handling facility. During the spring and summer of 2014, 2 wells were successfully drilled and completed. The first well was drilled to a depth of 3,800 feet, and the second well was drilled to a depth of 4,696 feet. Both wells were perforated to collect gas and fluid samples for further site characterization and analysis.

The monitoring wells will be strategically placed around the injection well based on data from the dynamic flow models. The monitoring wells will be used for downhole fluid sampling, tracer studies, and geophysical surveys.

The next phase of site development involves drilling additional wells and construction of the CO_2 pipeline system that will transport the CO_2 to the injection site. To coordinate site operations, BSCSP project managers are working with multiple partners and subcontractors, including, Vecta Oil and Gas, Altamont, and Schlumberger Carbon Services. Throughout the life of the project, the safety and risk management of all project personnel are top priorities, and detailed plans have been formulated to promote timely and efficient management of all site operations.

Hollow drill bits are used to extract long cylinders of rock material, known as cores. BSCSP acquired approximately 450 feet of core from both wells.



The first monitoring well was drilled to a total depth of 4,696 feet, with specific zones perforated to collect valuable data.

Background image: For the Kevin Dome project, two characterization wells have been drilled with an injection well and additional monitoring wells planned.

Permitting

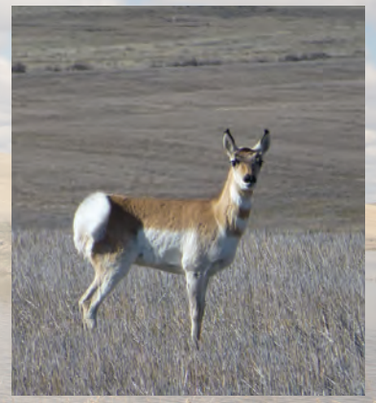
The Kevin Dome Project's permitting compliance strategy is to identify regulatory requirements early, incorporate them into the design process, ensure permit stipulations are followed in the field, and maintain working relationships with agencies. The project's regulatory framework is unique and complex because it is a federally funded project and managed by a State agency (Montana State University).

Due to the diversity of stakeholders, personnel, and agencies involved with the Kevin Dome Project, one project challenge has been ensuring that all involved team members are aware of the suite of permitting compliance regulations and stipulations. To achieve this objective, project managers have emphasized contractor training, education, and awareness to promote the project's "100 percent compliance" policy. Increased and consistent communication, including regularly scheduled conference calls, daily correspondence, and face-to-face meetings, has proven a successful strategy to ensure compliance.

In addition, it is important that BSCSP maintains amicable relationships with local residents near the Kevin Dome Project area. The Kevin Dome Project would not be possible without the cooperation of nearby landowners and community officials. Accordingly, project managers have made concerted efforts to establish trusting relationships with local residents through open-house meetings, newsletters, one-on-one meetings, and regular communication. The project team attributes much of the positive landowner relations to establishing a field office in town and hiring a local field manager. Having a local presence in the community has proven invaluable for project relations and has assisted with obtaining landowner permits. A permitting compliance specialist was also hired to evaluate regulatory requirements for upcoming project activities. This individual is involved in the design, planning, implementation, and monitoring phases of all permits. In coordination with the field manager, the permitting compliance specialist helps ensure field crews adhere to permits and regulations during construction and operations.

From the onset of the project, BSCSP was aware of protected environmental, biological, and cultural resources in the field area. To ensure protection of the cultural and historic resources, project managers worked closely with DOE, Montana State Historic Preservation Office, and representatives from tribes to develop a programmatic agreement that outlines the policies and procedures to avoid and minimize impacts to cultural resources for all project activities. Additionally, there were several wildlife-related stipulations for the project, providing added measures to limit effects to migratory birds, bald and golden eagles, black-footed ferrets, Sprague's pipit, and grizzly bears. Project activities involving construction or seismic work are scheduled to avoid the migratory and breeding season when possible. Other preventative actions include avoiding preferred habitats, installing reflective bird tags on permanent guide-wires, using freshwater-based drilling muds, installing netting over reserve pits, and maintaining a clean work area free of trash that may attract bears or other wildlife to construction sites. Other seasonal factors include working around the timing of landowner farming activities like tilling, seeding, and cropping. By being proactive and communicating these requirements to onsite contractors, BSCSP has successfully minimized the effects on wildlife species and crops.

Cultural sites, like this stone circle, are present within the project area and measures are in place to protect these resources from impact.



Project activities take measures to protect migratory birds and wildlife habitat.

Background image: Field crew conduct water sampling activities on private land located within the project area.

Public Outreach

Enhancing awareness and education about the Kevin Dome Project is a critical component of BSCSP outreach efforts. The project site is in a rural area located away from community centers. Most of the county can still be characterized as the rural west given the average size of farms in Toole County, Montana, is 2,686 acres. According to the 2010 U.S. Population Census, the population in Toole County is 5,324. Shelby, Montana, is the largest community in the area with a population of 3,376. The town of Sunburst has a population of 375 and the town of Kevin has a population of 154. Toole County's industries include agriculture and livestock; oil, gas, and wind development; retail trade; transportation and warehousing; education; and health and social services.

Due to the location and broad range of stakeholders involved in the project, including private landowners, city officials, tribal representatives, and various government agencies, frequent communication with stakeholders is a top priority. Effective and regular dialogue between project managers, partners, and local community members fosters collaboration and understanding about the project's objectives and long-term goals. For example, prior to any site development taking place, BSCSP project managers met with Toole County residents to discuss local perspectives on carbon capture and storage (CCS) and the selection of a nearby research area to conduct a large-scale CCS field project. Through a series of community interviews and open house meetings, BSCSP was able to engage with community members, build relationships in the Kevin Dome Project area, and establish key contacts relevant to the project's ongoing success. These early outreach activities were followed-up with the hiring of an onsite field manager who provides up-to-date information about the Kevin Dome Project and serves as the primary point of contact between project management and local residents. The field manager is also a landowner liaison for all project permitting and has a local office for visitors.

Other recent outreach and education activities have included classroom presentations, onsite tours for K-12 students, and community appreciation events. In addition, BSCSP produced and released an outreach education video featuring the project's seismic survey, called, "What's Shaking on Kevin Dome." This short film highlights the unique process of collecting underground geophysical data and included interviews with scientists and personnel involved with the project's seismic survey. For field updates, BSCSP maintains a blog to keep stakeholders aware of new activities and findings associated with the project.

Ongoing communications with private landowners, community officials, and tribal and government agencies is integral to the outreach framework of the Kevin Dome Project, and local feedback will continue to guide outreach efforts during the project's operational and post-injection phase.

BSCSP Director Lee Spangler being interviewed for the public outreach video, "What's Shaking on Kevin Dome," which highlights the project's unique seismic survey and geophysical activities.

Background image: Students from the local middle and high school participate in an onsite tour of the Kevin Dome Project area.

BIG SKY CARBON
SEQUESTRATION PARTNERSHIP

More information about the Big Sky Carbon Sequestration Partnership is available via the following resources:

Website: www.bigskyco2.org
Email: bigskycarbon@montana.edu
Phone: 406-994-3800

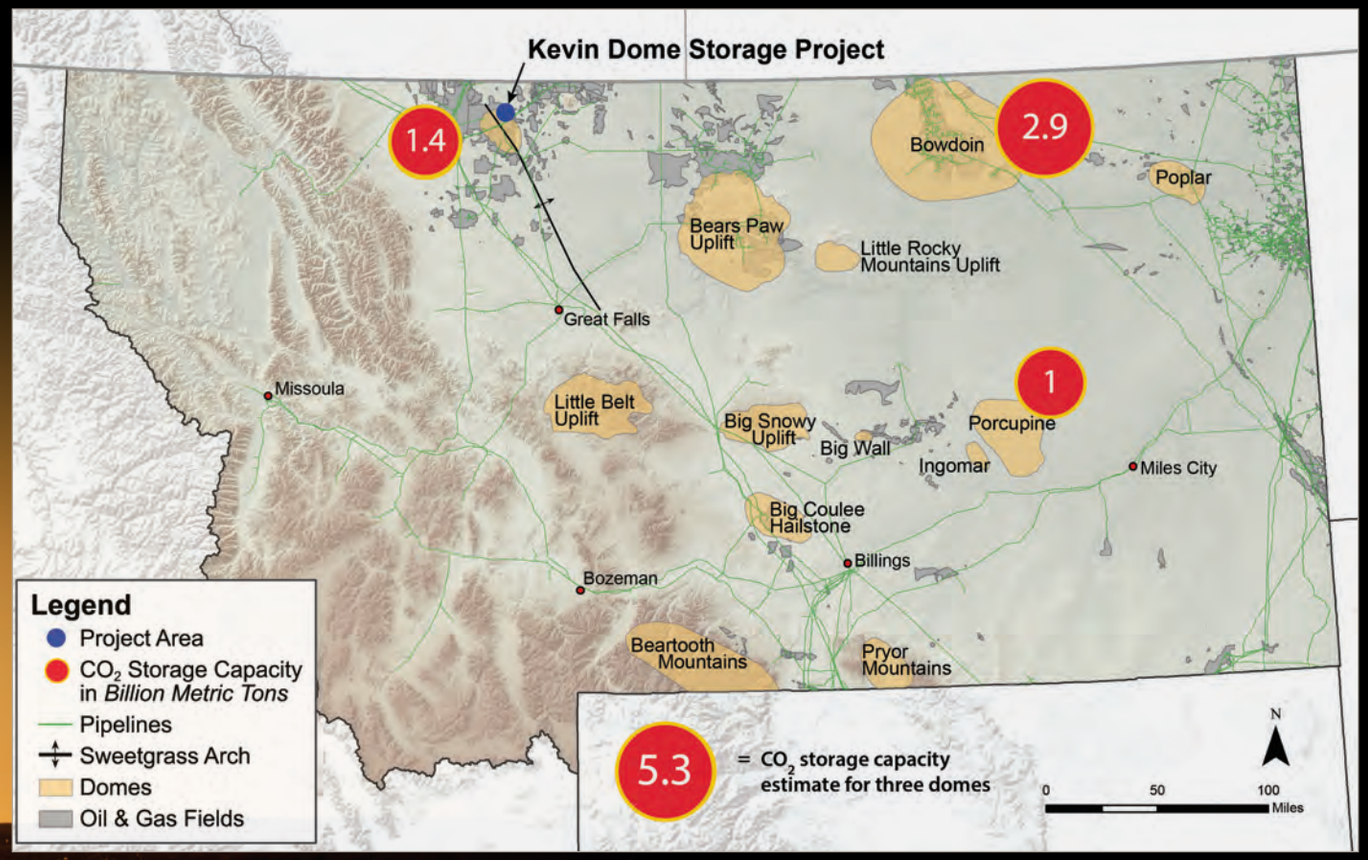
Commercialization of CCS in the BSCSP Region

The BSCSP Region possesses vast fossil reserves of coal and unconventional oil and gas that can provide energy security and economic growth. With 25 percent of the Nation's coal reserves (6 percent of the world's coal reserves) and emerging shale oil opportunities in the Bakken, restrictions on fossil use could have a large impact on economic opportunities. Conversely, other segments of Montana's economy could be impacted by climate change given the dependence of agriculture on snowpack and tourism on healthy forests and a pristine environment.

CCS has the potential to impact Montana's economy. The application of CO_2-enhanced oil recovery (EOR) in depleted oilfields could result in approximately 10 percent additional oil produced. Given that Montana has already produced more than 1 billion barrels of oil, CO_2-EOR can potentially add 100 million barrels of oil production to the State economy.

Kevin Dome has the potential to serve as a regional CO_2 storage center because of the dome's geologic properties, proximity to present and future sources of anthropogenic CO_2, and similarity of its geology to other large domes in Montana. The Kevin Dome Project will further the understanding of regionally significant formations (such as the Duperow) and provide relevant information on potential use of other analogous domes in the region. Capacity estimates for three of the many domes (Kevin, Bowdoin, and Porcupine) in Montana and Wyoming total 5.3 billion metric tons. The target storage formation in Kevin Dome, the Duperow, has estimated capacities of 15 to 59 billion metric tons in the North-Central Montana Province and 25 to 102 billion metric tons in the Williston Basin Province, totaling more than 100 years of storage potential for current stationary CO_2 source emissions in the region (14.6 billion metric tons).

The Kevin Dome Project will provide a foundation for utilizing this feature for two economically significant operations related to its potential as a CO_2 storage reservoir: (1) to store CO_2 from new, clean energy plants, and (2) to provide CO_2 to mature oilfields in the immediate region of the dome for EOR projects. The naturally occurring CO_2 in the dome can provide a buffer so that production rates of anthropogenic CO_2 and injection rates for EOR can be decoupled. The Kevin Dome Project will provide valuable information for testing this CO_2 "warehousing" or CO_2 hub concept.



Kevin Dome is located close to significant sources of energy development and sources of CO_2 emissions, including oil, coal, and natural gas production. It is one of several geologic domes in the region.

Background image: Oil and natural gas development is expected to increase in the Big Sky region, particularly given emerging shale oil opportunities in the Bakken.

MICHIGAN BASIN PROJECT

MRCSP
MIDWEST REGIONAL
CARBON SEQUESTRATION
PARTNERSHIP

Introduction

The Midwest Regional Carbon Sequestration Partnership (MRCSP) is performing the Michigan Basin Project to inject 1 million metric tons of carbon dioxide (CO_2) and demonstrate the potential for commercial-scale geologic CO_2 storage. The large-volume injection test is being conducted in collaboration with enhanced oil recovery (EOR) operations, which enables research on concurrent utilization of CO_2.

The Niagaran Pinnacle Reef Trend along the northern flank of the Michigan Basin is a regionally significant resource for hydrocarbon (i.e., oil and natural gas) production and CO_2 storage. The pinnacle reefs are oil-bearing dolomite and limestone structures deposited on a shallow marine shelf during the Silurian Period. The reefs exhibit vuggy porosity, occur at subsurface depths of 4,000 to 6,000 feet, and are overlain by low-permeability carbonates and evaporates. MRCSP is injecting high-purity CO_2 removed from natural gas at a nearby gas processing facility. Site characterization, monitoring, and modeling are being performed to better understand the CO_2 storage potential of carbonate reservoirs and generate valuable case-study data that can be applied to future carbon capture and storage (CCS) projects.

Background image: Field photograph of the central production facility at the MRCSP CO_2 injection site.

PROJECT HIGHLIGHTS

- The large-scale CO_2 injection project is being carried out across pinnacle reefs in different stages of oil production, including one late-stage reef, six active CO_2-EOR reefs, and one reef that has only undergone primary oil production.
- Since monitoring operations began on February 3, 2013, MRCSP has successfully injected and monitored the storage of more than 330,000 metric tons of new CO_2.
- Previous to MRCSP injection, more than 1,000,000 metric tons of CO_2 were already retained in these reefs due to past CO_2-EOR flooding. Data from these multiple fields will provide insight into the impact of geologic heterogeneity and hydrocarbon production history on CO_2 storage potential, which will help develop strategies for optimizing future CO_2 storage projects.

Location of the MRCSP Phase III test site and the Niagaran Pinnacle Reef Trend.

Site Characterization

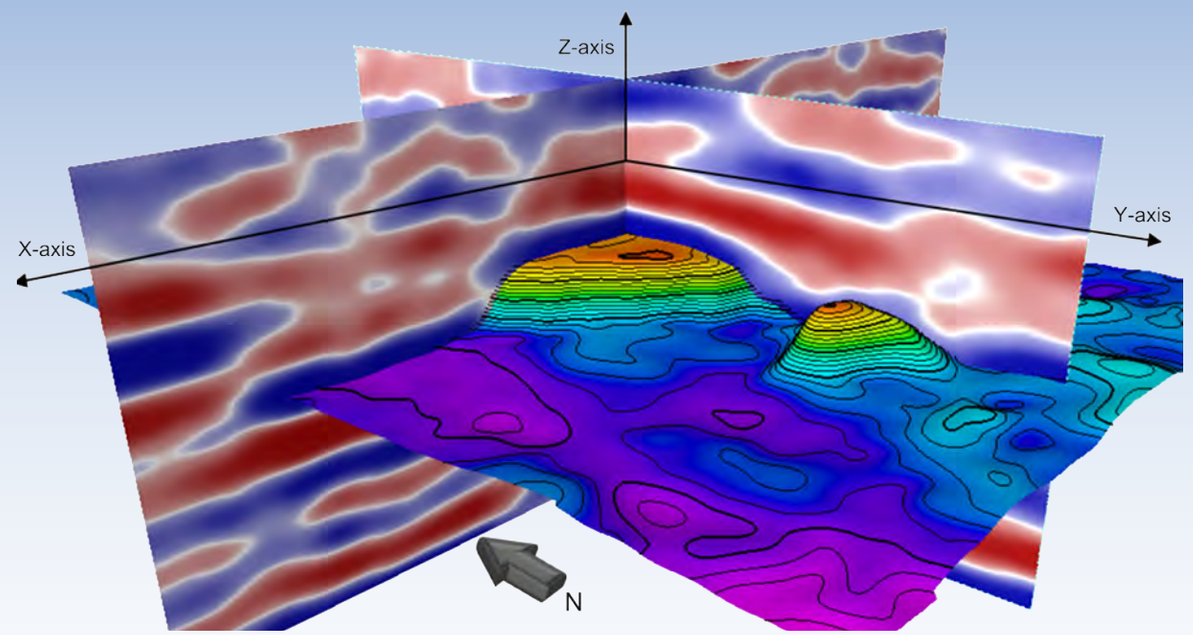
MRCSP supplemented historical wireline and 3-D seismic data with core data from analog reefs in the surrounding area to characterize the geology and build a geologic model for the late-stage reef. The distribution of large-scale, physical structures was primarily derived from seismic data, while existing wireline logs helped delineate the stratigraphy, infer the depositional environment, and characterize the porosity of the reef. The geologic characterization was augmented by using historical production data to build dynamic reservoir models.

MRCSP conducted additional site and baseline characterization with data from vertical seismic profiles (VSP), pulsed neutron capture (PNC) logs, interferometric synthetic aperture radar (InSAR), borehole gravity surveys, and fluid sampling.

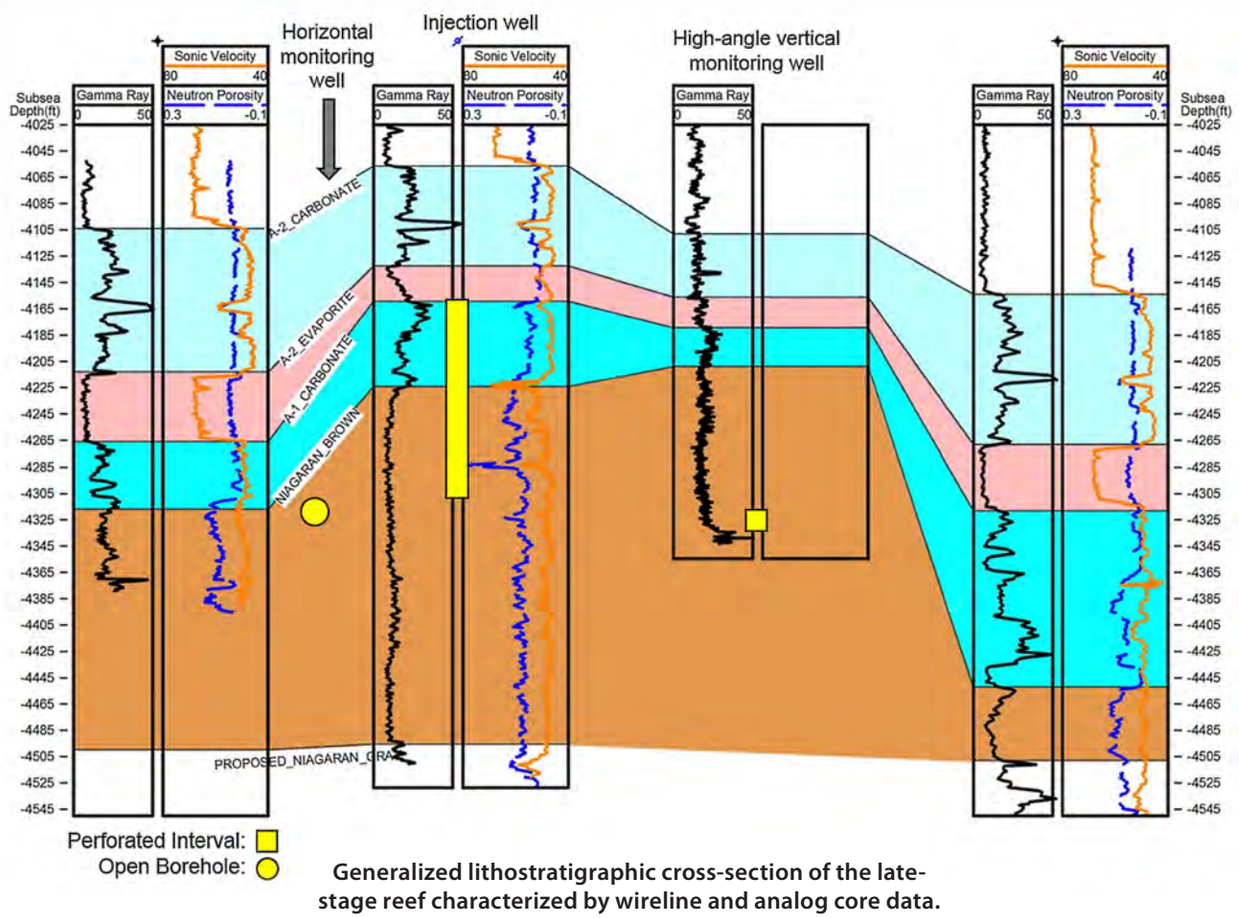
This activity included:

- Using VSP to provide high-resolution information on the subsurface geology of the reef. VSP data showed more internal reef structure compared to the 3-D seismic data, which is hampered by thick glacial till and high-angle geologic features of the reef.
- Using PNC wireline logging to characterize spatial and temporal distributions of fluids in the near-wellbore environment of the depleted reef. PNC logs have been effectively used for logging relative saturations of CO_2 and brine for CO_2 storage in saline reservoirs. However, the use in carbonates with various EOR histories, pressure regimes, and complex fluid compositions (e.g., brine, oil, gas, CO_2 mixtures) is still under investigation.
- Using InSAR to characterize historical ground movement and to collect baseline data prior to injection.
- Using borehole gravity data to derive density profiles for the late-stage reef to supplement reservoir evaluations and well log analysis.
- Conducting comprehensive geochemical analyses on fluid and gas samples to characterize the interactions between the CO_2 and reservoir components.

The methodologies implemented in the Michigan Basin Project establish a reference data set to provide a robust approach for characterizing these reefs.



Integration of well-log, core, and 3-D seismic data to characterize the topography and morphology of the reef.



Generalized lithostratigraphic cross-section of the late-stage reef characterized by wireline and analog core data.

Site Operations

The late-stage reef contains one vertical injection well, one horizontal monitoring well, and one high-angle vertical monitoring well. The injection well was previously used for CO_2 injection during EOR activities and is perforated across a 150-foot interval above the original oil-water contact to a measured depth of 5,460 feet. Original oil-water contact is 5,471 feet, measured depth. Both the elevation of the open borehole section of the horizontal monitoring well and the perforated interval of the high-angle vertical monitoring well are approximately at and slightly below the oil-water contact. MRCSP is injecting CO_2 into the late-stage reef at a maximum of 1,000 metric tons per day based on CO_2 availability. Discrete injection events ranging from 8 hours to 16 weeks have been followed by periods of no injection to provide data on pressure recovery. This pressure recovery data is being used to determine reservoir parameters, such as permeability, type of flow regime, and reservoir size, which are critical for numerical modeling and other analyses.

The six active EOR reefs targeted in the Michigan Basin Project contain 9 injection wells and 11 active producer wells. The CO_2-EOR operation in these six reefs behaves as a closed-loop recycling system, where produced CO_2 is compressed and dried, co-mingled with pure CO_2 from the natural gas processing facility, and re-injected back into the active EOR reefs. MRCSP is working to address how to best determine the amount of CO_2 being stored associated with EOR operations. The Michigan Basin Project also is developing validated reservoir models that can be used to estimate CO_2 capacity of EOR reefs at the end of the oil production life cycle.

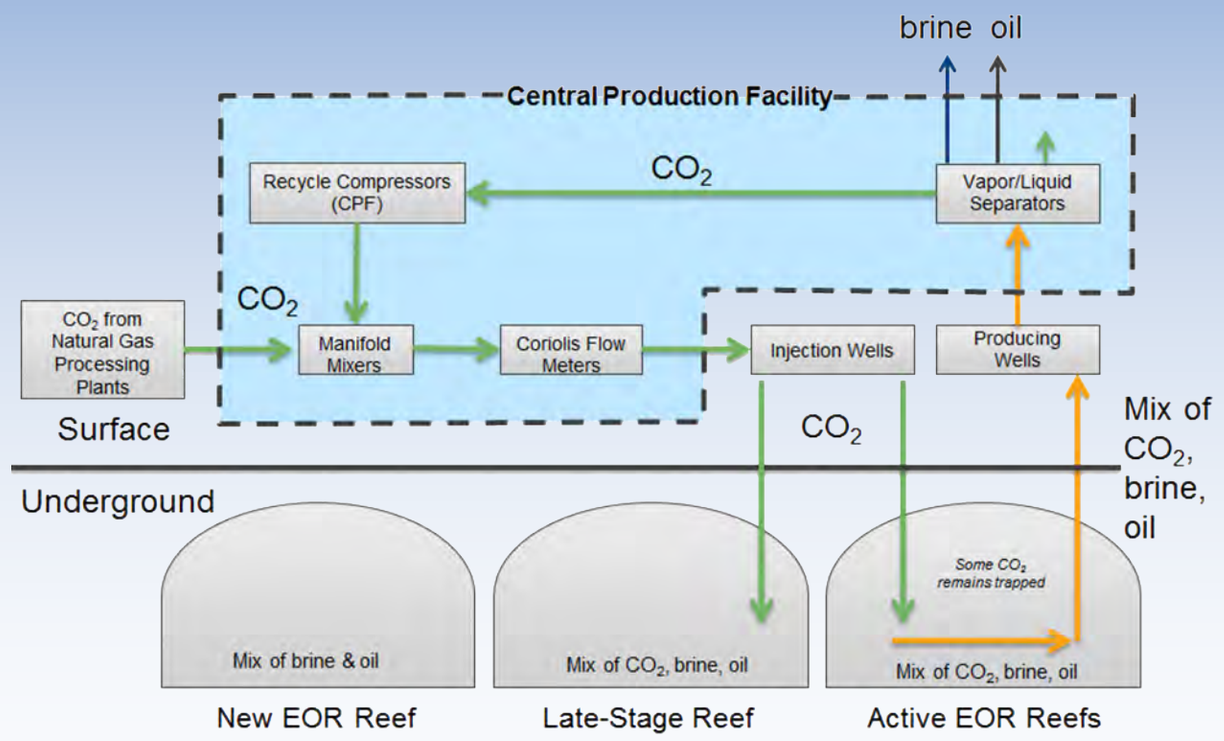


Diagram of CO_2 injection and recycling operations

Background image: CO_2 and mixed fluid pipelines at the central production facility can be used for production or injection. The white frost pipeline seen here is delivering new CO_2 to the facility.

Monitoring, Verification, Accounting, and Assessment

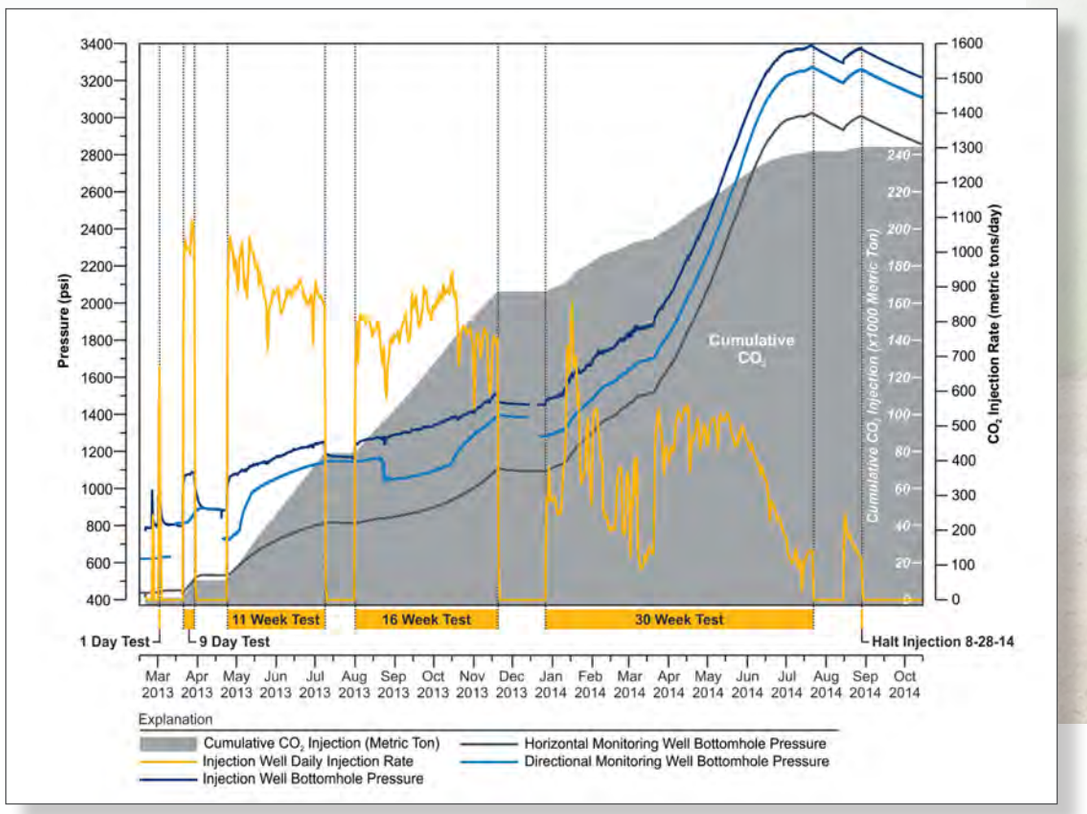
The late-stage reef is serving as the main reef for application of monitoring, verification, accounting (MVA), and assessment technologies. The objectives of the MVA plan are to record the behavior and ultimate fate of injected CO_2 and assess the utility of selected MVA technologies in large-scale CO_2 storage projects. Many of the MVA technologies are collecting data before, during, and at the end of the active injection phase. The closed carbonate reservoir provides an ideal system for testing the ability of these technologies to track and monitor CO_2 movement in the subsurface. The results of monitoring efforts will also help improve understanding of the utilization of depleted hydrocarbon reservoirs for permanent CO_2 storage.

PNC wireline logging is being used to evaluate spatial and temporal distributions of CO_2 in the near-wellbore environment. The Michigan Basin Project offers a unique opportunity to test and validate PNC logging tools under conditions of complex fluid compositions. PNC logs proved useful for recording the increasing presence of super-critical CO_2 and its containment within the reef.

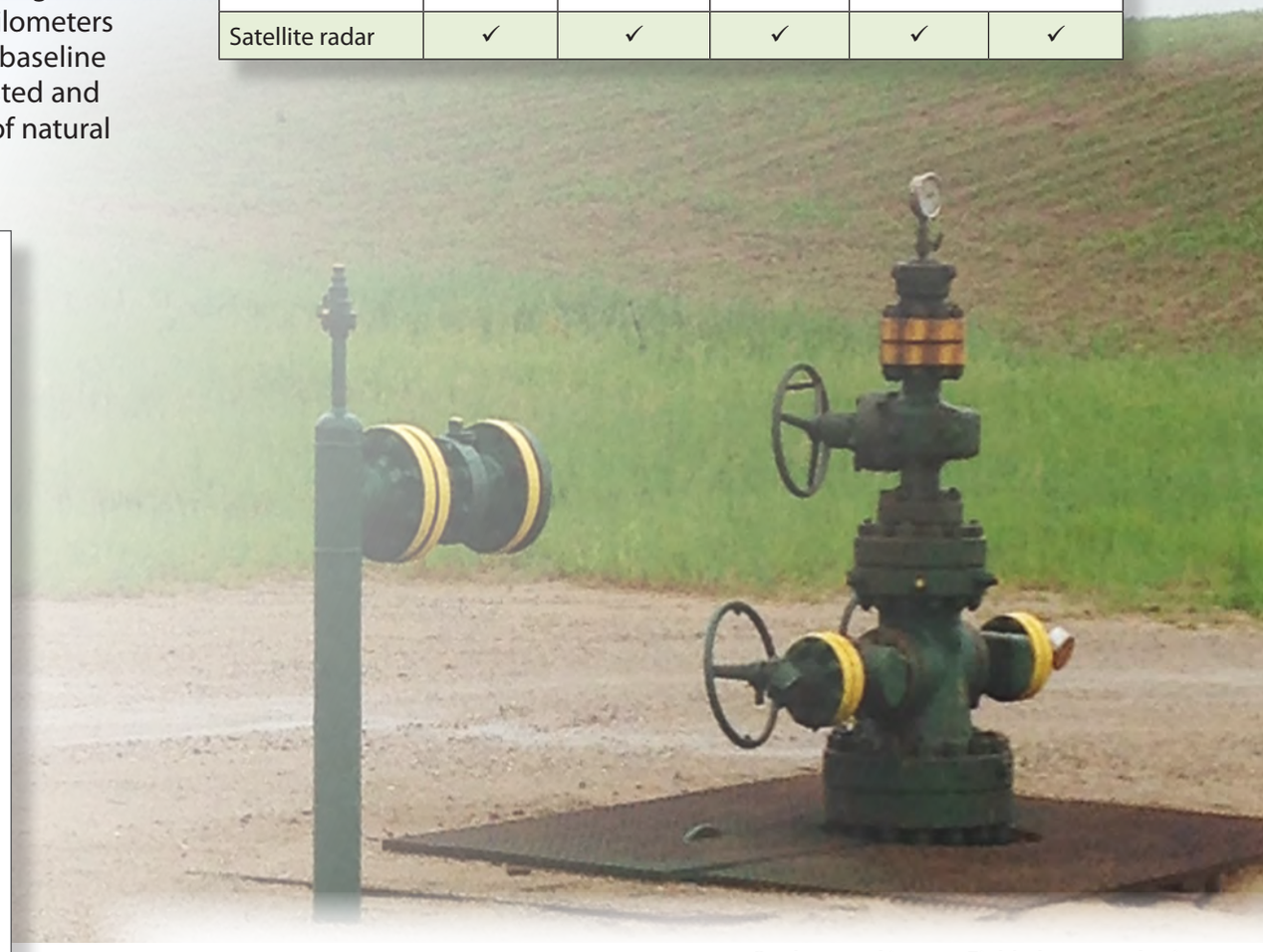
Remote-sensing, satellite-based interferometric synthetic aperture radar (InSAR) imaging is being used to monitor surface deformation in response to CO_2 injection. MRCSP delineated 80-square-kilometers encompassing the late-stage reef as the area of interest. MRCSP also conducted the initial baseline analysis more than 6 months before injection began. The nature of the terrain (largely forested and agricultural) is challenging for radar-based techniques, but it provides a reasonable density of natural reflectors. Artificial reflectors were installed to augment the data for injection monitoring.

Monitoring Plan for the Late-Stage Reef

Monitoring Activity	Pre-Injection	Early Injection	Mid Injection	Late Injection	Post-Injection
CO_2 flow		✓	✓	✓	
Pressure & temperature	✓	✓	✓	✓	✓
PNC wireline logging	✓		✓		✓
Borehole gravity	✓				✓
Fluid sampling	✓		✓		✓
VSP	✓				✓
Microseismic	✓			To be decided	
Satellite radar	✓	✓	✓	✓	✓



CO_2 flow and pressure monitoring in the three wells at the late-stage reef. Each injection event was followed by a shut-in period, during which pressure was allowed to stabilize. These injection fall-off tests were analyzed to estimate reservoir properties.



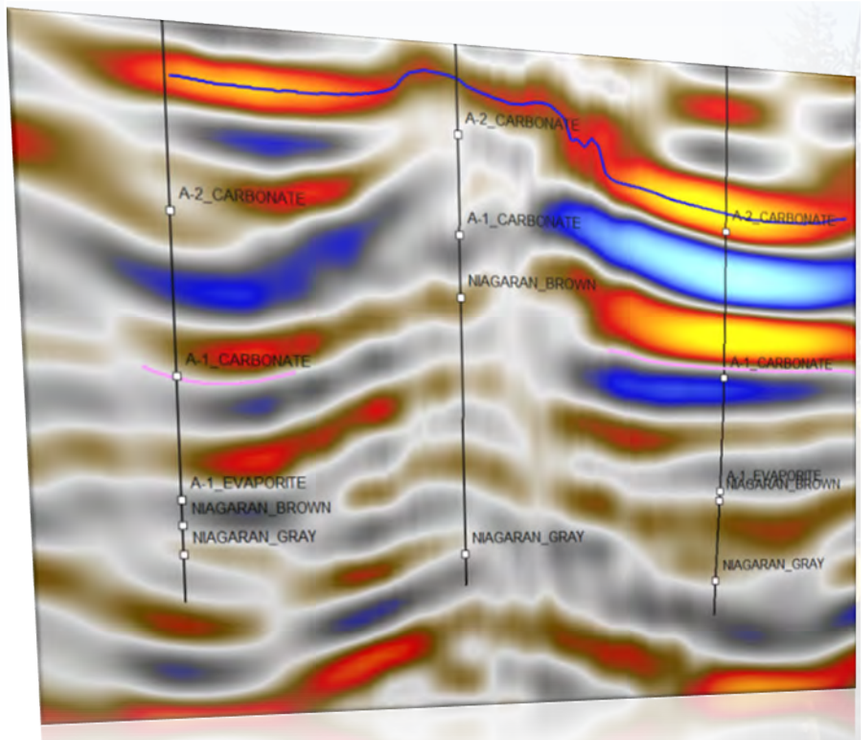
Background image: Field photograph of a monitoring well at the late-stage reef.

Monitoring, Verification, Accounting, and Assessment

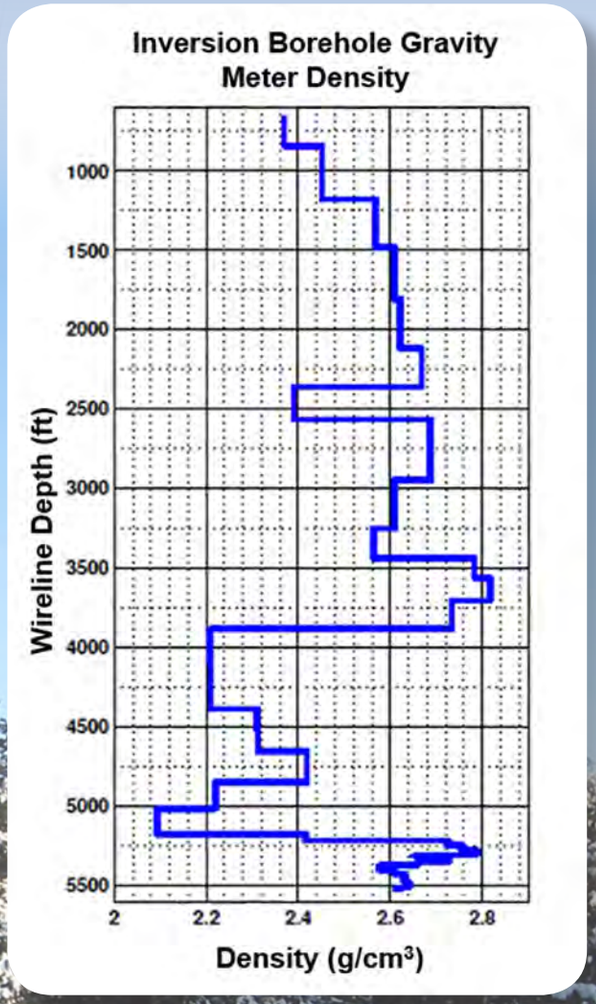
MRCSP employed microseismic monitoring at the Michigan Basin Project for a 10-day period at the start of injection to assess the potential effects of CO_2 injection on the mechanical properties and geologic structures of the late-stage reef. No CO_2-injection related microseismic events were recorded within the reservoir and caprock.

VSP and borehole gravity surveys will be repeated after CO_2 injection operations in the late-stage reef to identify any changes that can potentially be attributed to CO_2 injection, accumulation, and/or saturation.

The performance of MVA tools employed in late-stage reef operations will be documented to help guide monitoring plans for the other reefs targeted in the Michigan Basin Project. The MVA technologies validated in this project will be shared to promote optimization of commercial-scale CCS operations in the future.



Baseline image of subsurface obtained from VSP—a repeat survey is planned to image the distribution location of CO_2 within the reef.

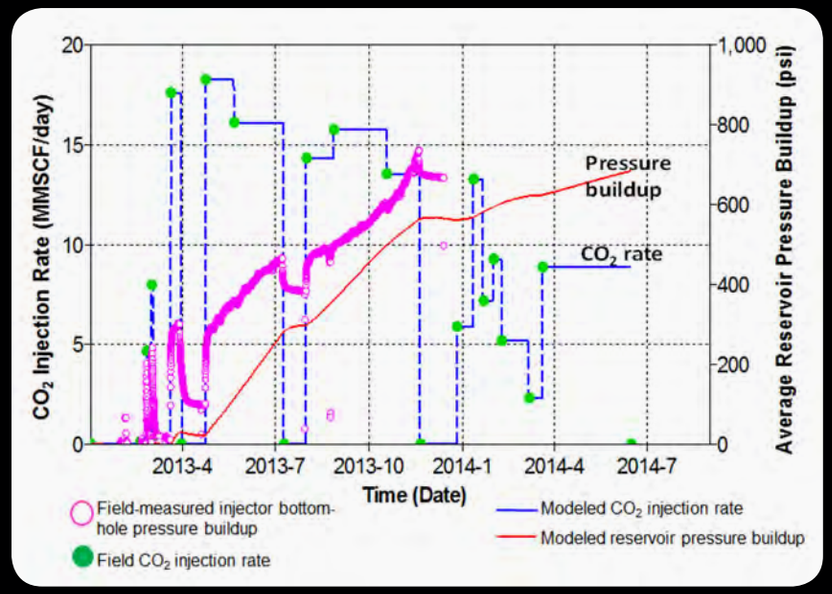


Background image: Photograph of borehole gravity meter survey operations. Inset shows the baseline density profile of the late-stage reef derived from gravity data. The intent is to repeat the survey at the end of CO_2 injection operations to detect changes in density caused by the accumulation of CO_2 within the pore spaces of the reef. For example, time-lapse measurements are expected to show an increase in density where CO_2 is denser than the void space it replaces.

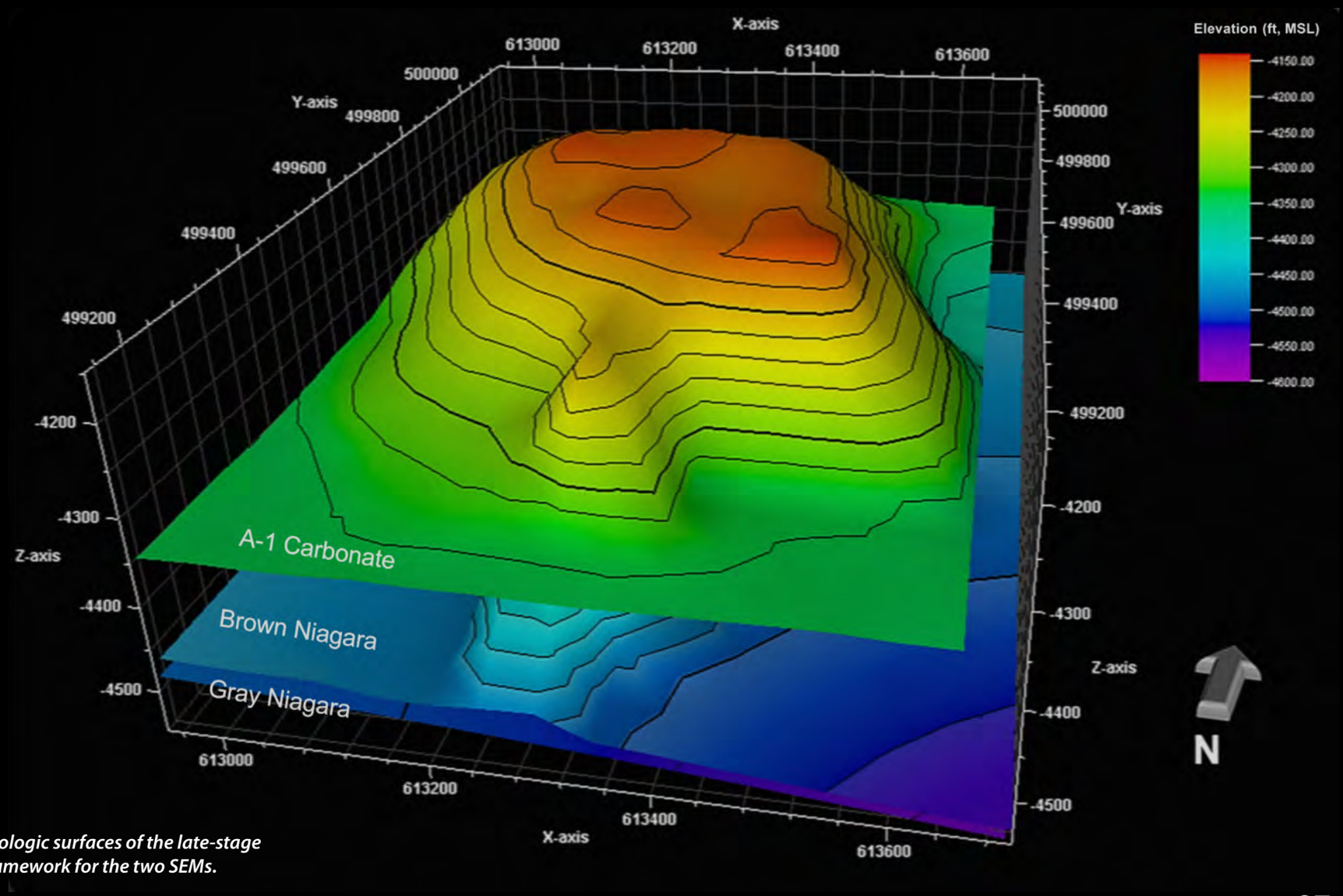
Risk Assessment, Simulation, and Modeling

The Michigan Basin Project risk assessment included a features, events, and processes (FEP) analysis, a risk pathway analysis, and an initial risk matrix analysis. MRCSP completed a systematic baseline survey of the site features to describe geologic setting, surface features, and risk pathways. MRCSP reviewed well records to identify all wells at the project sites and catalogued and described groundwater resources in the project area. The geologic setting was also reviewed to identify confining layers, faults, fractures, and other features that may affect CO_2 storage security. MRCSP identified no major risk items in the risk screening. Finally, MRCSP integrated risk items into characterization, monitoring, and operations at the field site.

In addition, MRCSP conducted modeling to determine constraints on CO_2 storage capacity, injectivity, and containment within complex carbonate systems. Two static earth models (SEM), a lithostratigraphic earth model (LSEM), and a sequence stratigraphic earth model (SSEM), were constructed for the late-stage reef to evaluate the effect(s) of increasing geologic detail on reservoir model accuracy. Both SEMs are being used in dynamic modeling for history matching of primary production and secondary recovery in the depleted reef. Dynamic reservoir modeling is being conducted to evaluate CO_2 injectivity and pressure-constrained storage capacity of the reef system. The goal is to develop a model that can effectively handle multicomponent fluid interactions and be successfully validated against field-observed reservoir pressure responses during CO_2 injection. History-matched and validated models are used for regional-scale field optimizations to predict CO_2 injectivity, as well as operational pressure and capacity limits.



History-matched model prediction of pressure buildup compared to CO_2 injection field data (no production).

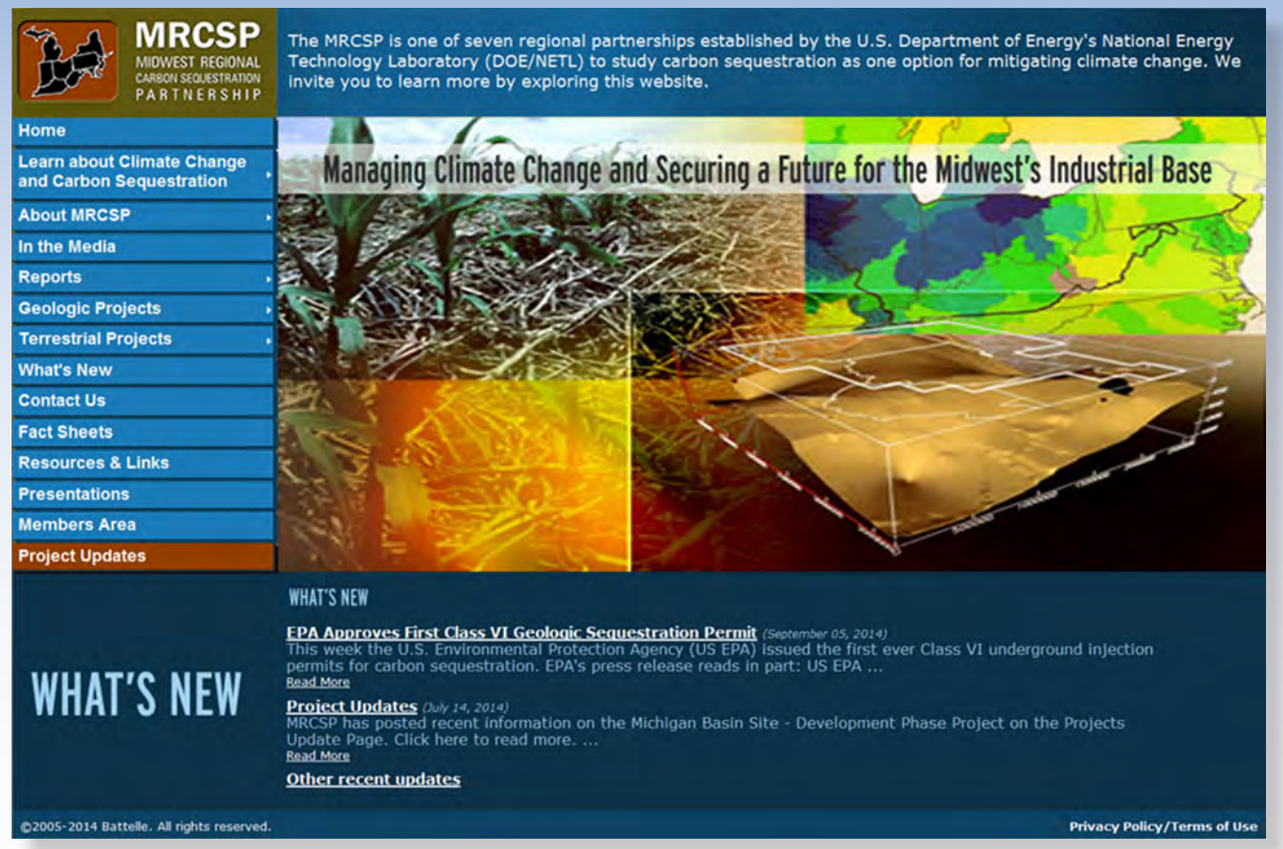


Background image: Geologic surfaces of the late-stage reef that formed the framework for the two SEMs.

Public Outreach, Knowledge Sharing/Dissemination

MRCSP developed and implemented a communications plan for the Michigan Basin Project. The experience gained during earlier small-scale field projects taught project developers to better understand and respond to stakeholder needs and contributed to best practices for public outreach and education for CO_2 storage projects. Through the Michigan Basin Project, MRCSP continues to build public awareness of CCS, establish best practices for distilling key information resulting from research, and develop demonstrations and methods to share that information.

The MRCSP outreach program seeks to develop clear communications about the safety and importance of CCS technologies, which MRCSP believes is critical for increasing public acceptance. Outreach materials are designed to address specific concerns, such as protection of groundwater resources, the costs and benefits of CCS, and comparisons with other sources of energy, such as renewable energy. Communicating the results of the Michigan Basin Project to a broad audience is also of particular interest to MRCSP members. MRCSP presents information on progress made and key findings at conferences and other information exchanges, annual partners meetings, site visits, media (e.g., press releases, interviews), outreach materials, and the partnership website. MRCSP also participates in DOE's Outreach Working Group, which is working to better understand and respond to questions about CCS. MRCSP scientists also are engaging the international CCS community through collaborations, site visits, and conferences.



The MRCSP provides information about the program on its website, www.mrcsp.org. Numerous topical reports, fact sheets, and other information are posted.

Please direct any questions or comments about MRCSP to:

T.R. Massey
614-424-5544
masseytr@battelle.org

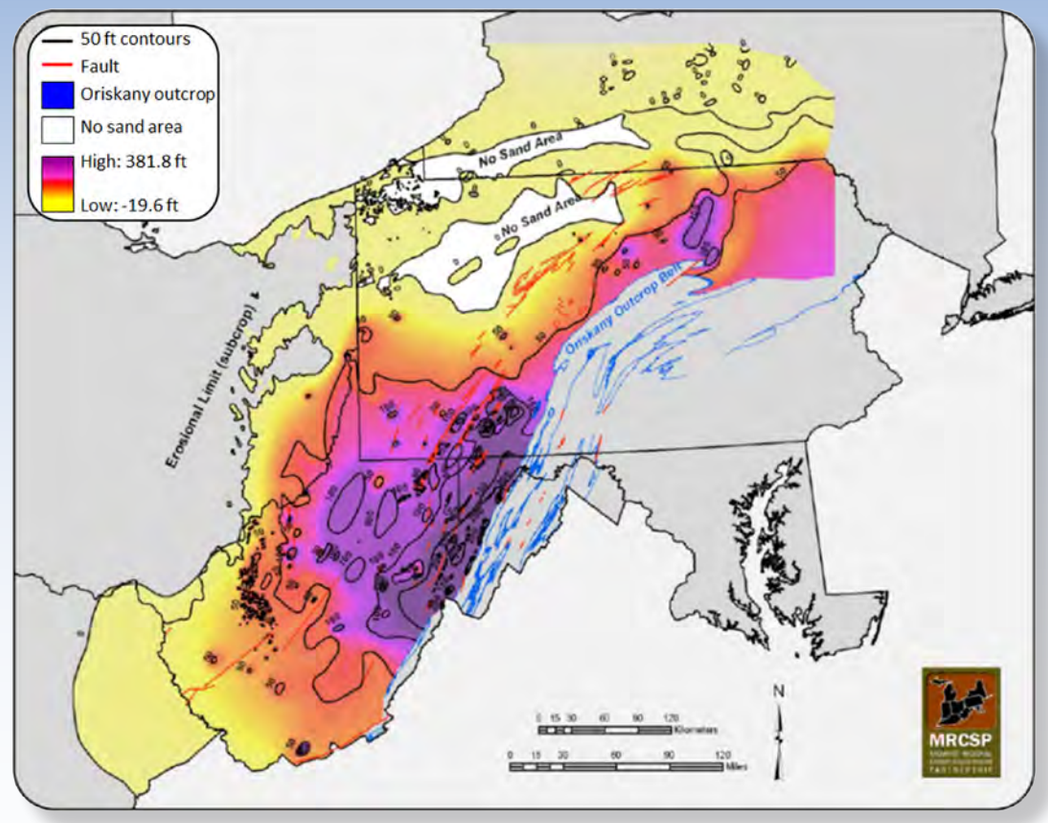
MRCSP members and visitors at the large-scale injection site. Progress is reported to members during annual partners meetings.

Commercialization of CCS in the MRCSP Region

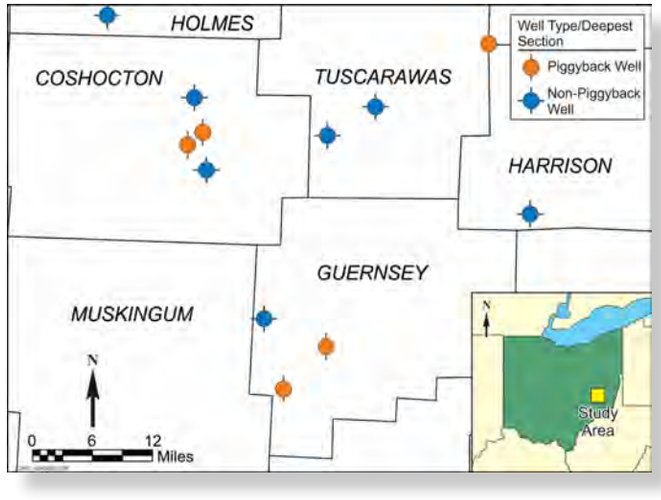
The Michigan Basin Project is helping to optimize strategies for CO_2-EOR and commercial-scale CO_2 storage. The Northern Niagaran Pinnacle Reef Trend, containing more than 700 pinnacle reef structures, exhibits potential for supporting large-scale CCS operations. Many other oilfields in the MRCSP region also are candidates for CO_2-EOR. The tools developed and implemented in the Michigan Basin Project can be used to help increase capabilities for commercial deployment of CCS within a region of the United States that relies on fossil energy. The methodologies, technical expertise, and lessons learned from this project will contribute to the development of best practice manuals (BPMs) for future EOR and commercial CO_2 storage projects.

The Michigan Basin Project has resulted in support for additional research on the CO_2 storage potential of the MRCSP Region. In conjunction with the MRCSP, the Ohio Coal Development Office is sponsoring work to identify and characterize geologic formations in eastern Ohio as part of a long-term, collaborative effort to assess the potential for geologic CO_2 storage in the Ohio River Valley and adjacent areas. This includes examining major depleted oil and gas fields in Ohio. Some of these fields are carbonate formations that serve as prime candidates for EOR. The validated methodologies, data, and results from the Michigan Basin Project will help guide characterization efforts and mitigation strategies.

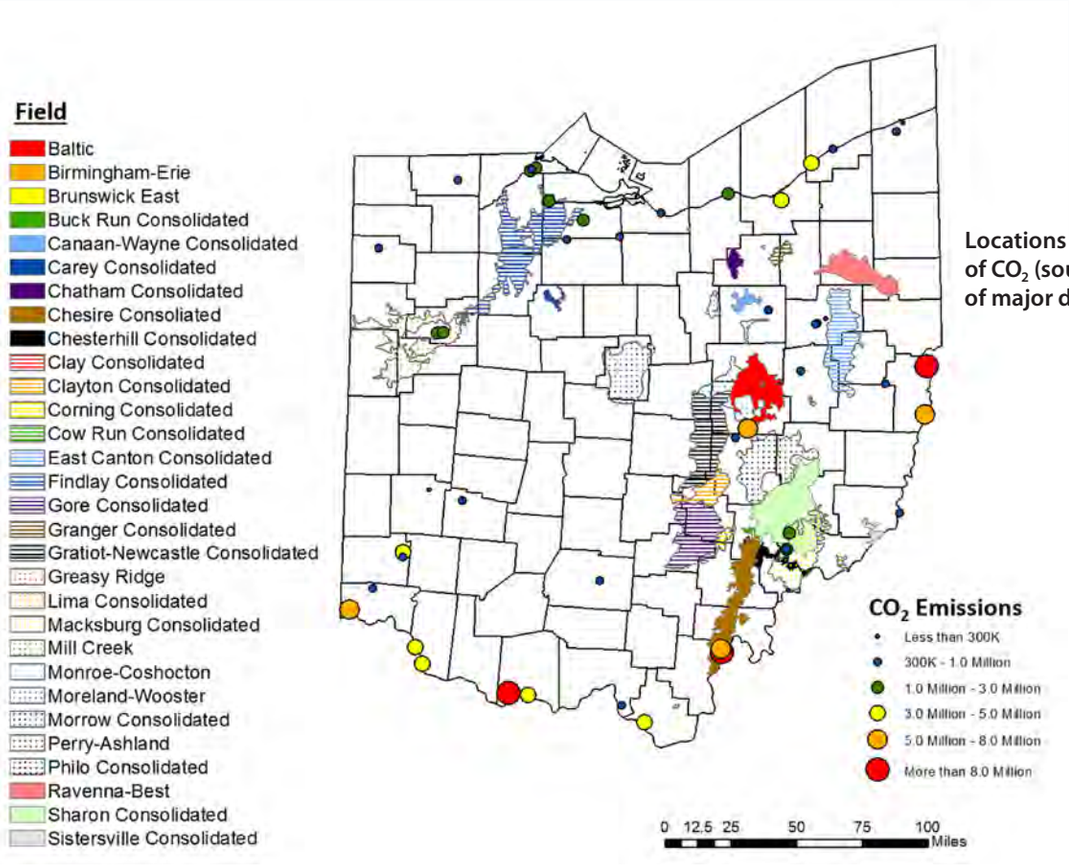
Regional characterization is a significant component of developing a regional mitigation strategy. The MRCSP region has many large stationary CO_2 sources located in close proximity to geologic storage resources. Geologists from MRCSP member states are collaborating to define storage reservoirs suitable for existing and future sources of CO_2, communicating with oil and gas drillers to fill data gaps, and supporting industry in evaluating CO_2 storage options. This research will be of value to the regional economy by helping to develop robust and cost-effective means for reducing greenhouse gas (GHG) emissions.



Gross thickness contour map of the Oriskany Sandstone developed through collaboration of the region's geological survey.



Locations of piggyback wells in Ohio counties to further characterize potential saline storage opportunities in the Appalachian Basin.



Locations of the 50 largest emitters of CO_2 (sources) alongside locations of major depleted oilfields in Ohio.

Small-Scale Field Projects

CO_2 Storage in Unmineable Coal with Enhanced Coalbed Methane Recovery

CONSOL ENERGY, INC.

Northern West Virginia

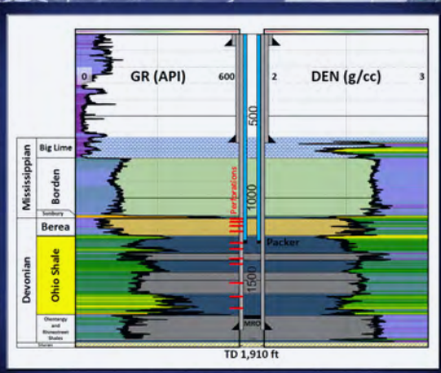
Eastern Kentucky

Western Virginia

Southern Kansas

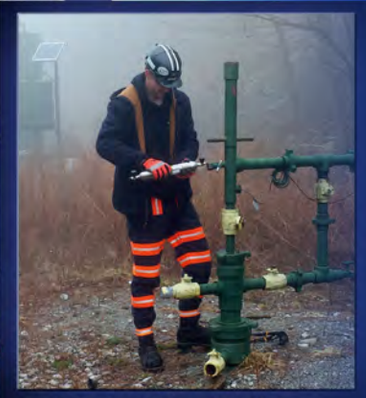
Small-Scale Field Test Demonstrating CO_2 Sequestration in Arbuckle Saline Aquifer and by CO_2-EOR at Wellington Field, Sumner County, Kansas

UNIVERSITY OF KANSAS CENTER FOR RESEARCH



Assessment of CO_2 Enhanced Natural Gas Recovery in Shale Gas Reservoirs

KENTUCKY GEOLOGICAL SURVEY
ADVANCED RESOURCES INTERNATIONAL



Injecting Carbon Dioxide into Unconventional Storage Reservoirs in the Central Appalachian Basin, with an Emphasis on Enhanced Coalbed Methane Recovery, to Validate Prior Geologic Characterization

VIRGINIA CENTER FOR COAL AND ENERGY RESEARCH, VIRGINIA TECH

Small-Scale Field Projects

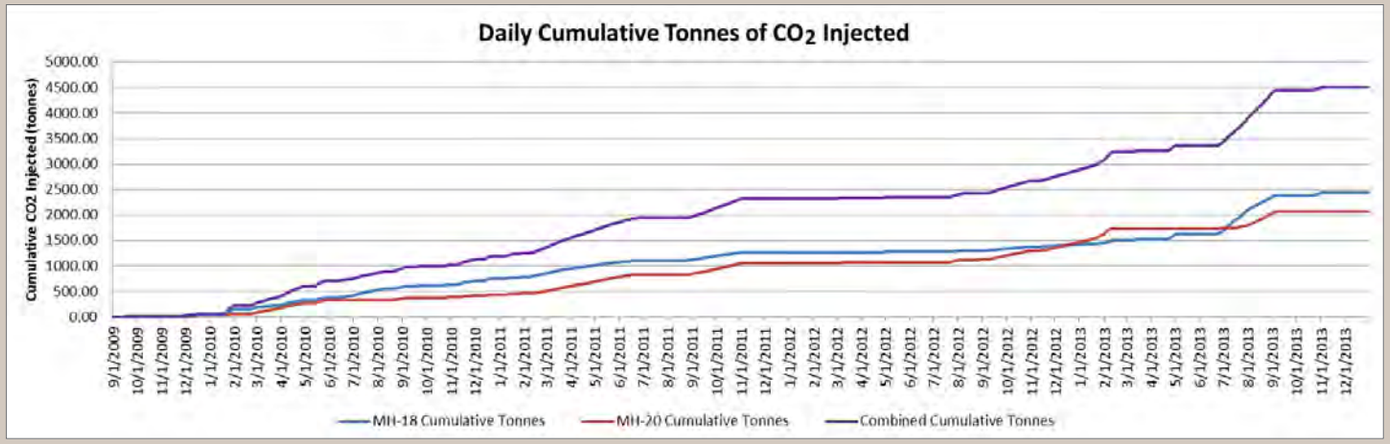
Background image: Virginia Tech Research Team at Shale Test Site in Morgan County, Tennessee.

CO_2 Storage in Unmineable Coal with Enhanced Coalbed Methane Recovery

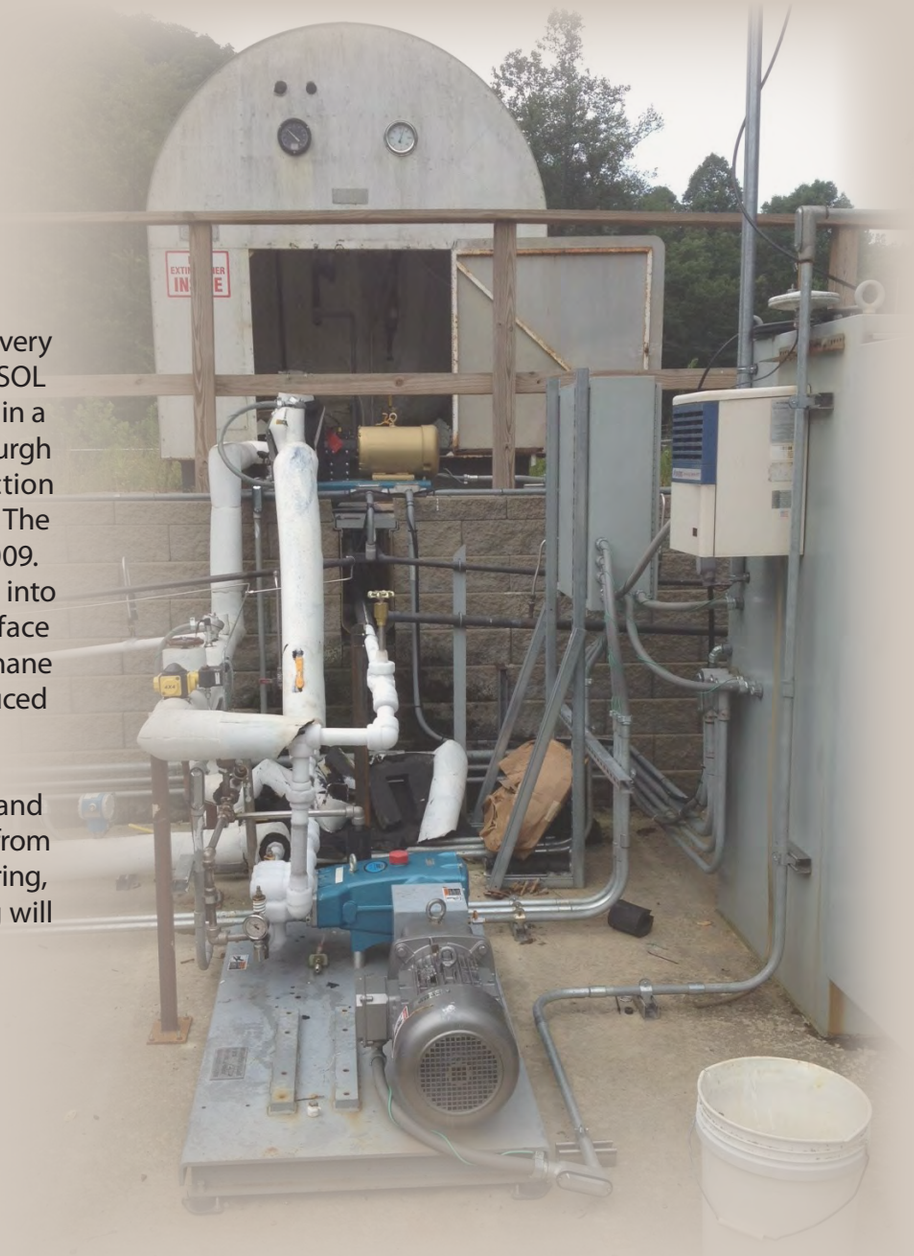
The Marshall County Project

CONSOL Energy has conducted a pilot test in Marshall County, West Virginia, to evaluate enhanced coalbed methane recovery and simultaneous CO_2 storage in an unmineable coal seam in the Northern Appalachian Basin. Researchers from CONSOL Energy, West Virginia University, and NETL are collaborating in this effort. Horizontal coalbed methane wells were drilled in a modified 5-spot pattern over a 200-acre area into the Upper Freeport coal seam and separately into the overlying Pittsburgh coal seam. These wells have been producing coalbed methane for more than 10 years. A Class II Underground Injection Control (UIC) permit was obtained from the West Virginia Department of Environmental Resources Office of Oil and Gas. The Upper Freeport production wells were converted to CO_2 injection wells and CO_2 injection commenced in September 2009. Through the expiration of the UIC permit, 4,507 metric tons of CO_2 were injected at a maximum pressure of 1,286 psig into an unmineable region of the Upper Freeport coal seam located at a depth of 1,200 to 1,800 feet, depending on surface topography. The impacts of CO_2 injection into the center wells on the production and composition of the coalbed methane produced in the peripheral and overlying wells are being monitored. Injection ceased when the coalbed methane produced from one of the peripheral wells indicated CO_2 arrival in early September 2013.

The pilot test incorporates numerous site characterization and monitoring activities including: (1) monitoring the gas and water produced from numerous active coalbed methane wells and abandoned deep gas wells in the Area of Review and from two observation wells drilled for the project, (2) groundwater monitoring, (3) stream water monitoring, (4) soil gas monitoring, (5) perfluorocarbon tracer testing, (6) tilt meter observations, and (7) seismic observations. Environmental monitoring will continue through 2015.



CO_2 was intermittently injected into the Upper Freeport coal seam over 4 years, beginning in September 2009 and concluding in November 2013. During this time, a total of 4,507 metric tons of CO_2 was injected.



Background image: The modified liquid CO_2 pump used at the Marshall County, West Virginia, project site.

Advanced Resources International, Inc.

UNIVERSITY OF KENTUCKY Kentucky Geological Survey

Crossrock Drilling • Blue Flame Energy
Schlumberger Carbon Services • Chesapeake Appalachia
Midwest Regional Carbon Sequestration Partnership

Assessment of CO_2 Enhanced Natural Gas Recovery in Shale Gas Reservoirs

The Kentucky Geological Survey (KGS) evaluated data acquired during a test conducted in a shale gas well using CO_2. KGS teamed with Advanced Resources International (ARI) and other partners to integrate core, advanced well logs, production, and other data from several sites across Kentucky to construct a model, use reservoir simulation to characterize the gas shale, and establish an experimental protocol.

At the Sulfur Spring project site, Johnson County, eastern Kentucky, the Crossrock SS-#1 test well was offset by three monitoring wells: a shallow twin well to the Mississippian Big Lime (SS-#1A) and two Devonian Shale penetrations (SS-#2 and SS-#3). The SS-#1 well measured 1,910 feet deep. The well was perforated from the Lower Huron Member of the Ohio Shale to the overlying Mississippian Sunbury Shale then fracture-stimulated with nitrogen and shut in. Each of the four wells was equipped with monitors to continuously record wellhead pressures and temperatures. Baseline logging established a pre-test flow profile and shale lithologic data for comparison to post-test logging. A total of 78.9 metric tons of CO_2 was pumped in three stages at rates of 2.3 metric tons to 4.5 metric tons per hour with 12 to 48 hours allowed for pressure falloff. Shut-in pressure averaged approximately 320 psig and treatment pressures ranged from 600 psig to 950 psig. A post-test pulsed neutron log was acquired. The well was flowed back through a meter run that included a mudlogging unit to record gas-composition data. Multiple spinner log passes were made during flowback to acquire a post-test flow profile.

Preliminary findings revealed that CO_2 can be pumped with equipment normally used for nitrogen fracture stimulation. An effective permeability increase was observed, and linear flow indicates an open fracture network. Although the test volume of CO_2 was small, results suggest the potential for CO_2 to displace fluids in shales, and no pressure or gas composition changes were observed in any of the three monitoring wells. Analysis of the surface and bottom-hole pressure data was conducted.

Background image: Onsite CO_2 facilities with storage vessel (far left), over-the-road transport with transfer pump (left), and CO_2 connected to a nitrogen fracture stimulation truck (right) where the CO_2 was vaporized, heated to 100 °F, pressurized, and pumped to the SS-#1 test well.

KU KANSAS GEOLOGICAL SURVEY
The University of Kansas

Small-Scale Field Test Demonstrating CO_2 Sequestration in Arbuckle Saline Aquifer and by CO_2-EOR at Wellington Field, Sumner County, Kansas

The University of Kansas Center for Research project aims to inject up to 40,000 metric tons of CO_2 into the Arbuckle Group in Sumner County, Kansas. The Arbuckle Group is an extensive saline formation in southern Kansas consisting of a basal porous sandstone succeeded by a thick porous and permeable dolomite with alternating confining layers. Additionally, up to 30,000 metric tons of CO_2 will be injected into the overlying Mississippian age oil reservoir. This dual injection allows both geologic CO_2 storage in a saline formation and CO_2-EOR potential to be investigated. Thick shales and shallow evaporites overlie the oil reservoir and safely isolate the 3,650-feet deep injection zone. The Mississippian CO_2-EOR injection is scheduled to begin in spring of 2015 and will be followed by injection into the Arbuckle saline formation, pending approval of an EPA Class VI well permit submitted June 2014.

Drilling/workover activities to be completed include (1) an Arbuckle observation borehole; (2) a Mississippian CO_2 injector for EOR under a Class II injection permit; (3) the equipping of a borehole for Arbuckle injection under a Class VI injection permit; and (4) the recompletion of an existing Arbuckle well, an additional deep observation borehole, and shallow monitoring wells. Additionally, a set of existing Mississippian boreholes that offset the Arbuckle injection borehole will be equipped for detecting both CO_2 and tracers (Figure 2).

The study uses state-of-the-art monitoring techniques to track and visualize the location of stored CO_2 throughout the injection. Monitoring includes: (1) in situ and surface seismic methods; (2) gas and fluid reservoir sampling; (3) InSAR (Interferometric Synthetic Aperture Radar) with continuous GPS to detect millimeter-scale surface deformation; and (4) an array of 15 3-component broadband seismometers.

Activities conducted during pre-injection have led to building and refining geologic, seismic, and engineering models that can predict the location and composition of the CO_2 plume (Figure 1). These techniques have integrated data previously collected from the study area, including an existing 3-D seismic survey covering 10 square miles, more than 1,600 feet of core from two characterization wells, and a suite of wireline logs calibrated by whole core analyses. An initial estimate of the plume radius from the CO_2 injection in a lower Arbuckle injection zone is less than 2,000 feet from the injection well (Figure 2).

This dual CO_2 disposal/EOR project will advance the science and practice of carbon storage in the mid-continent by providing a highly constrained test of the models, evaluating MVA best practices tailored to the geologic setting, optimizing remediation methods and risk assessment, and providing technical information and training to foster additional projects and facilitate public discourse on liability and risk management issues.

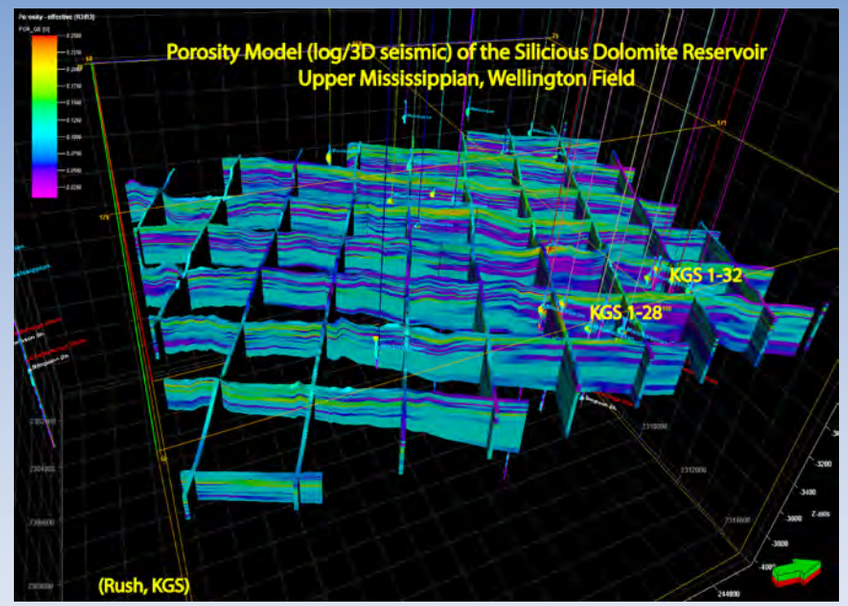


Figure 1. Porosity model of Wellington Field. The objective of the modeling is to accurately predict the spatial distribution of the CO_2 plume and to validate the model by monitoring an injection test.

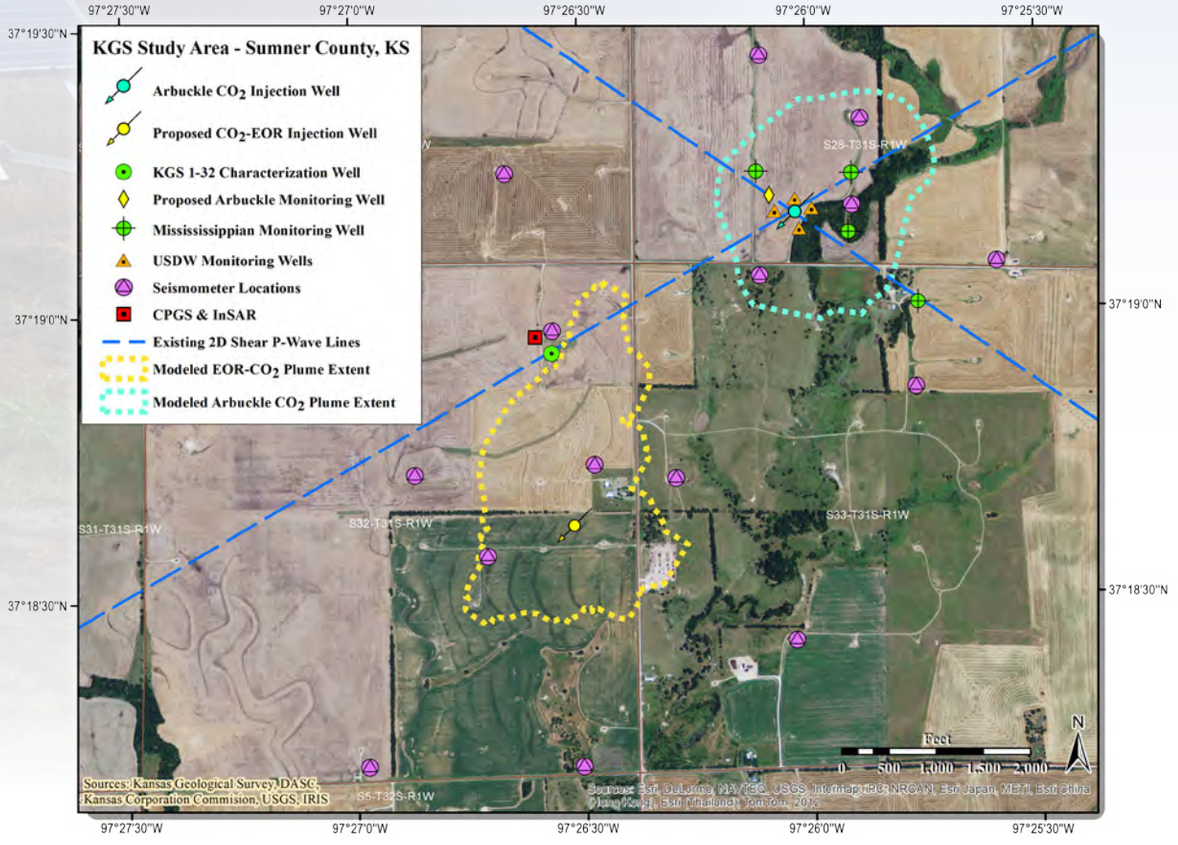


Figure 2. Extensive MVA activities around Wellington Field site.

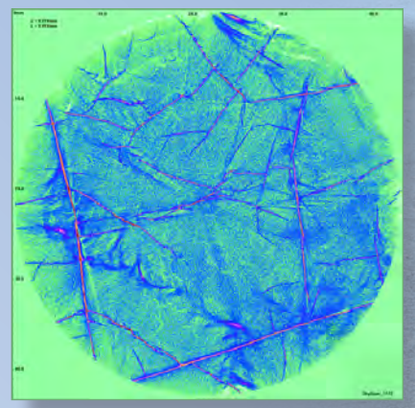
Background image: Recent activity in Wellington Field.

Injecting Carbon Dioxide into Unconventional Storage Reservoirs in the Central Appalachian Basin, with an Emphasis on Enhanced Coalbed Methane Recovery, to Validate Prior Geologic Characterization

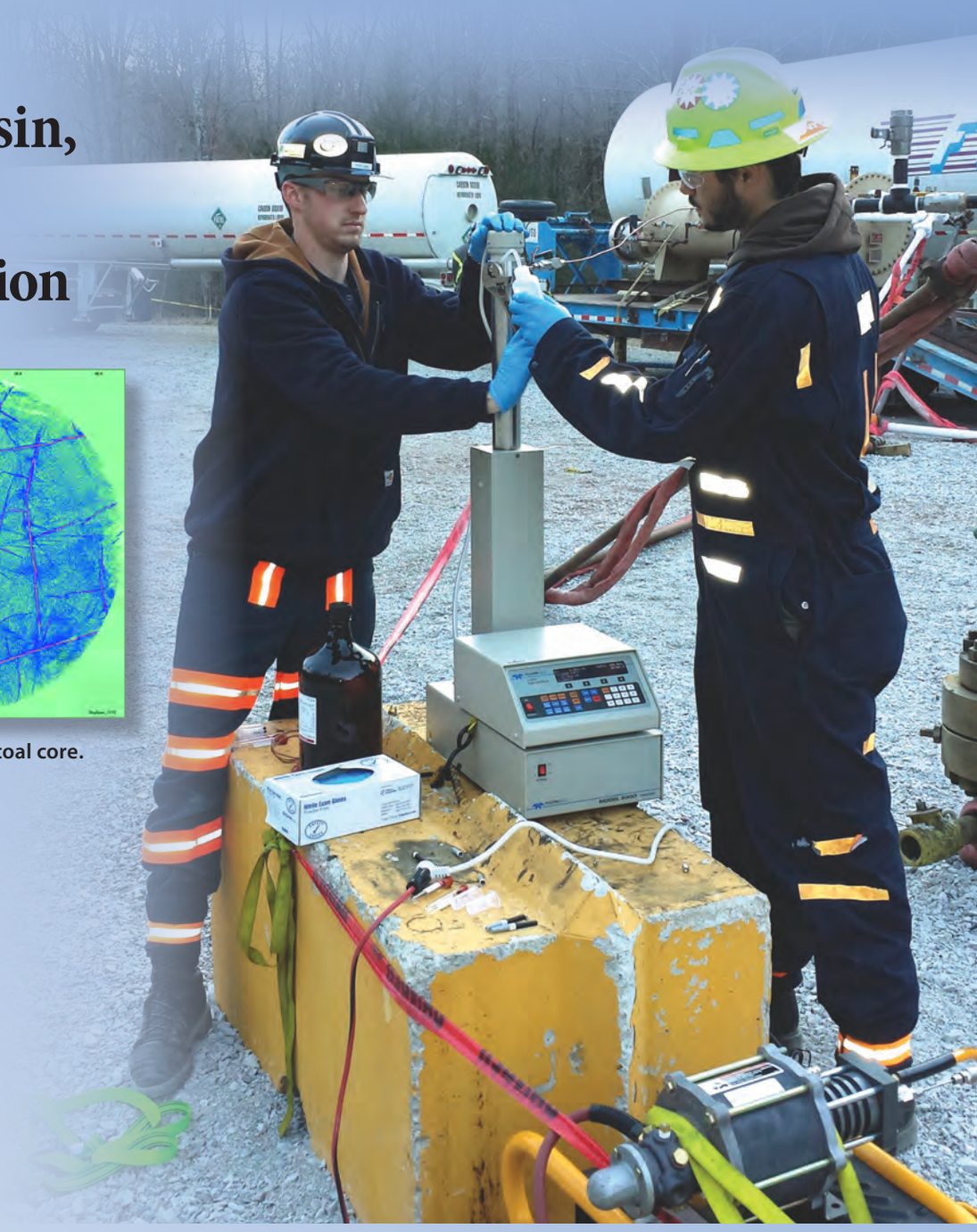
Virginia Tech is evaluating the long-term CO_2 storage potential of unmineable coal seams and organic shales in the Central Appalachian Basin. The research team is designing and implementing characterization, injection, and monitoring activities to test the ability of unconventional formations (coal and organic shales) to store CO_2 economically and safely and track CO_2 migration throughout the injection and post-injection phases. The project is also evaluating enhanced coalbed methane recovery and enhanced gas recovery applications during CO_2 injection activities.

Carbon dioxide storage in developed and depleted organic shale layers, such as the Chattanooga, is being investigated with a targeted CO_2 injection test into a depleted shale gas well. The injection of 458 metric tons of CO_2 into a legacy horizontal shale gas well in Morgan County, Tennessee, was successfully completed in March 2014. The initial plan was to inject CO_2 for 10 days at 40 to 50 °F and less than 800 psig injection pressure, although the injection rate was slightly less than planned. Over the 12¼ days of continuous injection, CO_2 went downhole at an average of 37 metric tons per day. Temperature was a limiting factor on the injection rate because of the lower than anticipated reservoir pressure. Monitoring at this site will continue throughout the shut-in and flowback periods.

Preliminary studies serve as the basis for a larger scale injection of up to 20,000 metric tons into unconventional geologic formations in the Oakwood coalbed methane field in Buchanan County, Virginia, where continuous CO_2 injection into an unmineable coal seam will occur for 1 year. The benefit of this research lies in proving the CO_2 storage potential of unmineable coal seams and organic shales with enhanced coalbed methane recovery and enhanced gas recovery in stacked unconventional formations in central Appalachia.



A MicroCT scan of coal core.

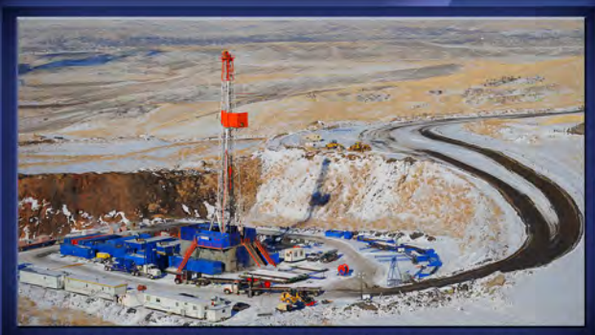


Background image: Research team injecting fluorinated tracers at the shale test site in Morgan County, Tennessee.

ARRA Site Characterization Projects

Site Characterization of the Highest-Priority Geologic Formations for CO_2 Storage in Wyoming

UNIVERSITY OF WYOMING



Characterization of Most Promising Sequestration Formations in the Rocky Mountain Region

UNIVERSITY OF UTAH

Characterization of Pliocene and Miocene Formations in the Wilmington Graben, Offshore Los Angeles, for Large Scale Geologic Storage of CO_2

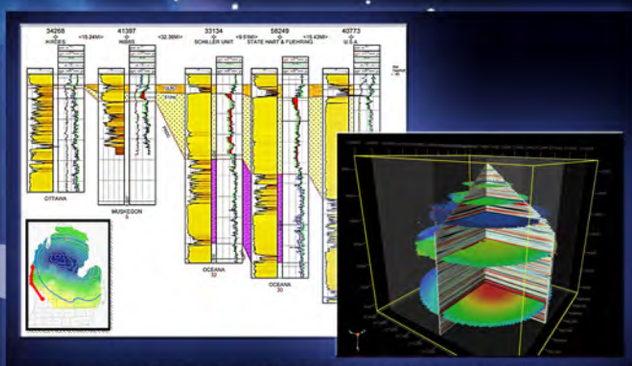
GEOMECHANICS TECHNOLOGIES

Modeling CO_2 Sequestration in a Saline Reservoir and Depleted Oil Reservoir to Evaluate the Regional CO_2 Sequestration Potential of the Ozark Plateau Aquifer System, South-Central Kansas

UNIVERSITY OF KANSAS

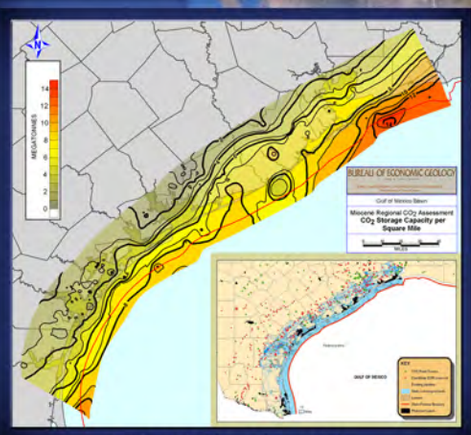
Characterization of the Triassic Newark Basin of New York and New Jersey for Geologic Storage of Carbon Dioxide

SANDIA TECHNOLOGIES, LLC



An Evaluation of the Carbon Sequestration Potential of the Cambro Ordovician Strata of the Illinois and Michigan Basins

ILLINOIS STATE GEOLOGIC SURVEY



Gulf of Mexico Miocene CO_2 Site Characterization Mega Transect

UNIVERSITY OF TEXAS AT AUSTIN

Site Characterization for CO_2 Storage from Coal-fired Power Facilities in the Black Warrior Basin of Alabama

UNIVERSITY OF ALABAMA

Geologic Characterization of the South Georgia Rift Basin for Source Proximal CO_2 Storage

SOUTH CAROLINA RESEARCH FOUNDATION

Wyoming, Utah, and Montana

Utah and Wyoming

South-Central Kansas

New York and New Jersey

Illinois, Indiana, Kentucky,and Michigan

Offshore Los Angeles

Alabama

South Carolina and Georgia

Gulf of Mexico

*American Recovery and Reinvestment Act (ARRA)

Characterization of Pliocene and Miocene Formations in the Wilmington Graben, Offshore Los Angeles, for Large-Scale Geologic Storage of CO_2

The Los Angeles Basin presents an opportunity for large-scale geologic CO_2 storage. Due to its large population and 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 12 major power plants and oil refineries that produce more than 5 million metric tons of fossil fuel-related CO_2 emissions each year.

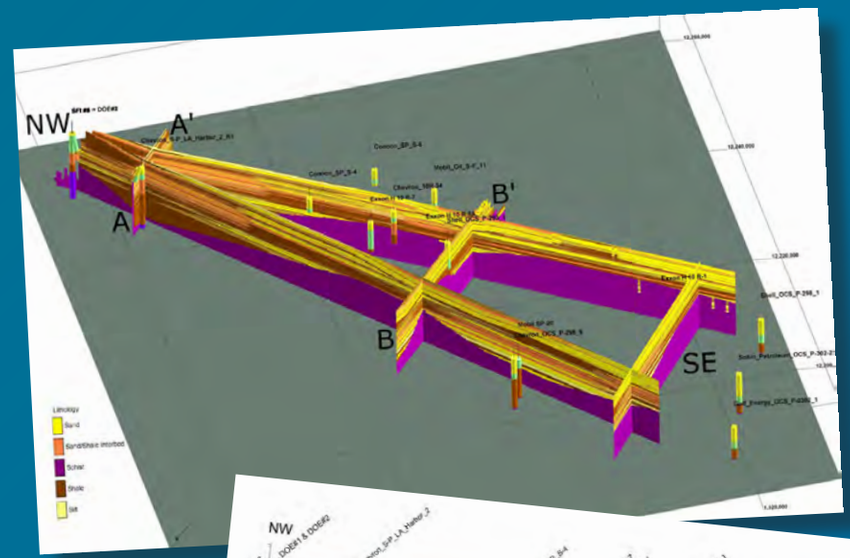
GeoMechanics Technologies worked to characterize the Pliocene and Miocene sediments in the Wilmington Graben, offshore of Los Angeles, California, for high-volume CO_2 storage. The Graben is located offshore of the Los Angeles and Long Beach Harbor area, making it accessible yet geologically isolated from the nearby Wilmington oilfield and onshore areas. These sediments span more than 5,000 feet of vertical interval with an estimated storage resource of more than 100 million metric tons of CO_2.

The project team analyzed and interpreted existing geologic data within the region, including detailed exploration well log data and 2-D and 3-D seismic data. New seismic lines were acquired to fill in current data gap areas and two new characterization wells were drilled and logged. This information was integrated with existing geologic interpretations for adjacent onshore areas to help characterize optimal areas for CO_2 storage and seals to safely store CO_2. Integrated 3-D geologic and geomechanical models for the Wilmington Graben were developed to simulate the fate and transport of injected CO_2 in the subsurface and to assess risks.

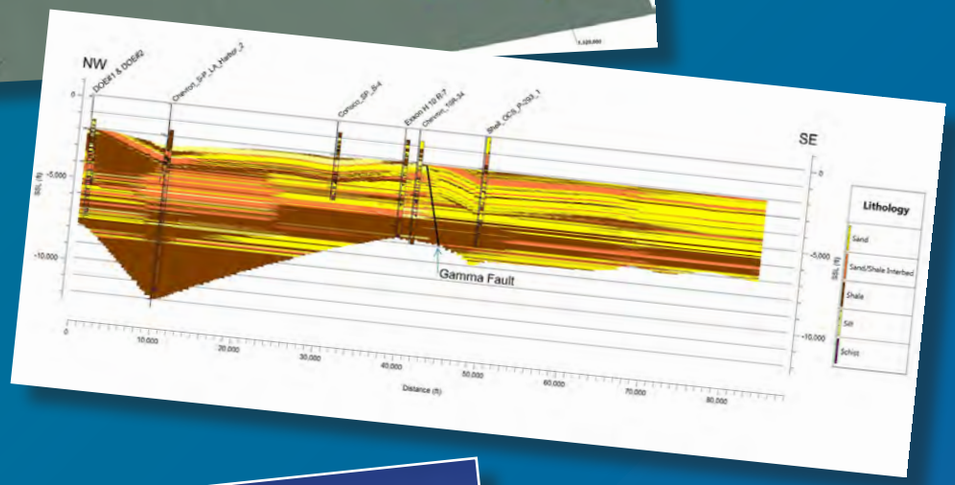
This project contributed to the understanding of injectivity, containment mechanisms, rate of dissolution and mineralization, and storage capacity of the Wilmington Graben and associated analogous basins. This effort also provided greater insight into the potential for offshore geologic formations to safely and permanently store CO_2.

Preliminary Minimum Storage Capacity for the Los Angeles Basin*	
Low	49.4 MMT
Medium	194 MMT
High	523 MMT

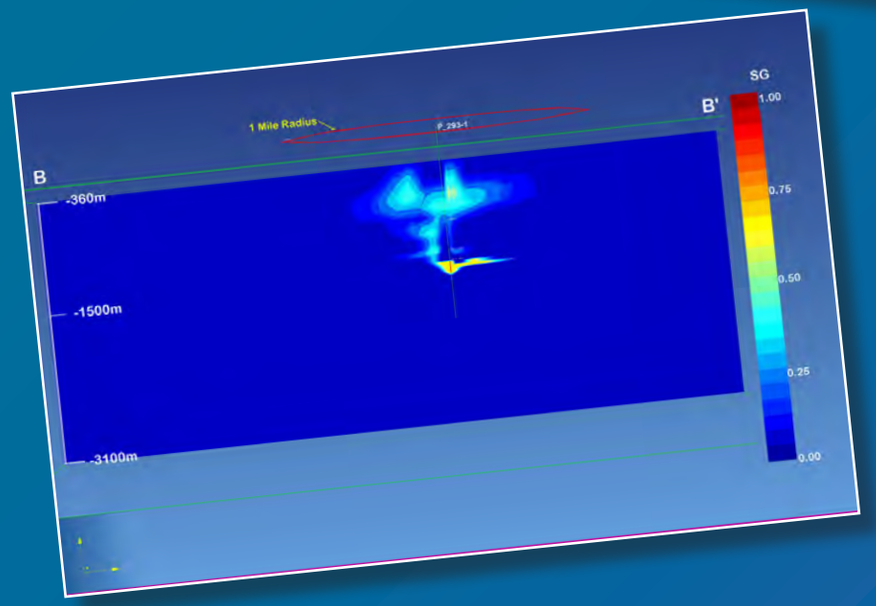
** Using the NETL supplied efficiency factors*



Geologic fence diagram for the Wilmington Graben with lithologies interpolated between known wells.



NW-SE cross section along entire center length of the Wilmington Graben showing interpolated lithologies.



Distribution of gaseous CO_2 after 30 Years of injection in center of cross section B-B'.

SANDIA TECHNOLOGIES, LLC

Sandia Technologies, LLC

TriCarb CO_2 Consortium for Carbon Sequestration

Conrad Geoscience Corp.
Geologic & Environmental Consultants

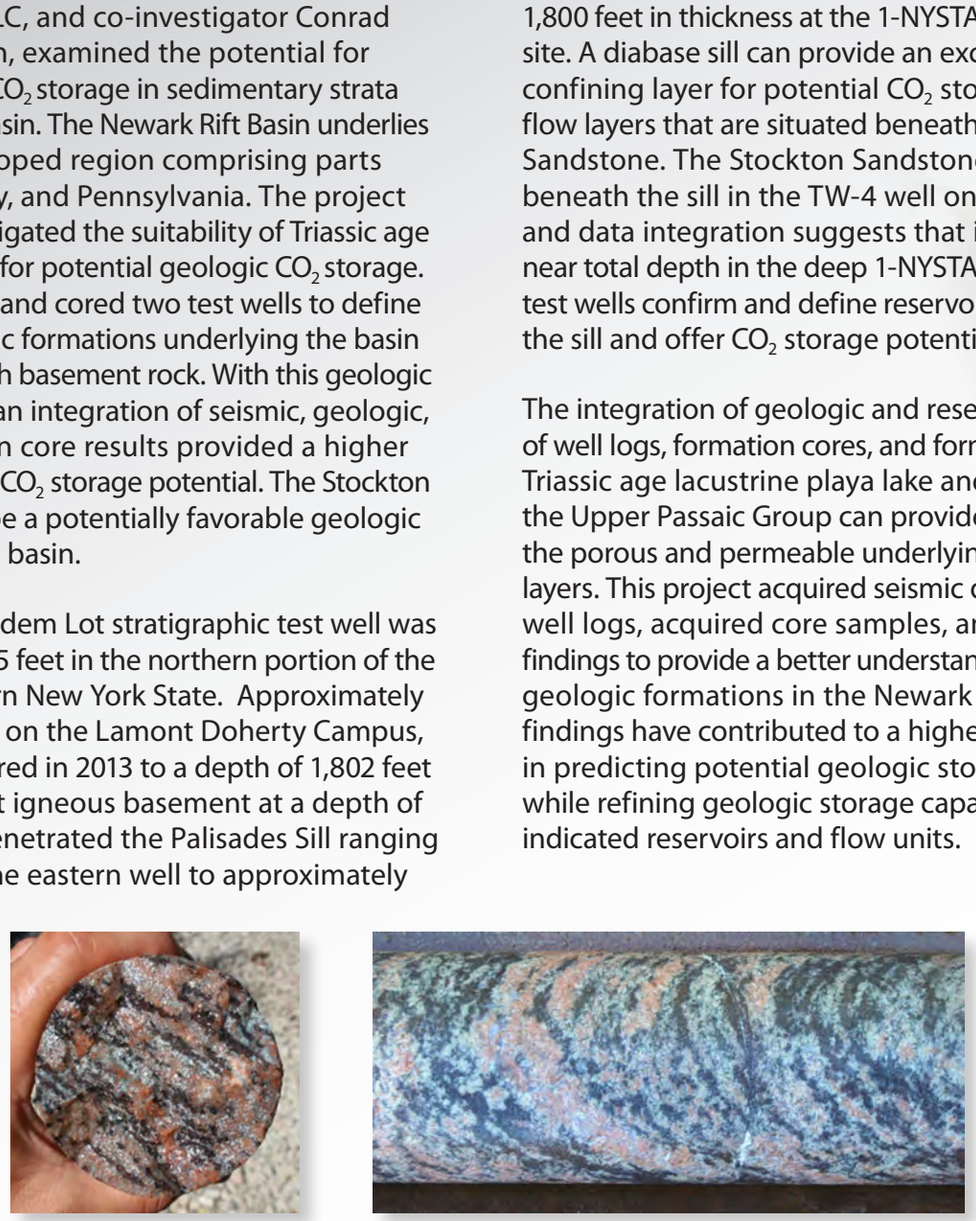
TriCarb Consortium for Carbon Sequestration • Columbia University's Lamont Doherty Earth Observatory • Rutgers University scientists
New York State Museum • Schlumberger Carbon Services • Lawrence Berkeley National Laboratory's Earth Science Division

Characterization of the Triassic Newark Basin of New York and New Jersey for Geologic Storage of Carbon Dioxide

Sandia Technologies, LLC, and co-investigator Conrad Geoscience Corporation, examined the potential for large-scale, permanent CO_2 storage in sedimentary strata within the Newark Rift Basin. The Newark Rift Basin underlies an industrialized, developed region comprising parts of New York, New Jersey, and Pennsylvania. The project characterized and investigated the suitability of Triassic age sedimentary formations for potential geologic CO_2 storage. The project team drilled and cored two test wells to define the sedimentary geologic formations underlying the basin and to document or reach basement rock. With this geologic characterization phase, an integration of seismic, geologic, borehole, and formation core results provided a higher resolution assessment of CO_2 storage potential. The Stockton Formation is known to be a potentially favorable geologic storage formation in the basin.

In 2011, the 1-NYSTA Tandem Lot stratigraphic test well was drilled to a depth of 6,855 feet in the northern portion of the Newark Basin in southern New York State. Approximately 9 miles south-southeast on the Lamont Doherty Campus, TW-4 was drilled and cored in 2013 to a depth of 1,802 feet and contacted apparent igneous basement at a depth of 1,712 feet. Both wells penetrated the Palisades Sill ranging from 800 feet thick in the eastern well to approximately 1,800 feet in thickness at the 1-NYSTA Tandem Lot deep drill site. A diabase sill can provide an excellent seal and dense confining layer for potential CO_2 storage reservoirs and flow layers that are situated beneath it within the Stockton Sandstone. The Stockton Sandstone was encountered beneath the sill in the TW-4 well on the Lamont campus, and data integration suggests that it was likely observed near total depth in the deep 1-NYSTA Tandem Lot well. The test wells confirm and define reservoirs are present beneath the sill and offer CO_2 storage potential.

The integration of geologic and reservoir characterization of well logs, formation cores, and formation fluids indicated Triassic age lacustrine playa lake and mudbank shales of the Upper Passaic Group can provide an effective seal for the porous and permeable underlying sandstone reservoir layers. This project acquired seismic data, drilled borehole well logs, acquired core samples, and integrated these findings to provide a better understanding of the subsurface geologic formations in the Newark Rift Basin. These findings have contributed to a higher degree of accuracy in predicting potential geologic storage opportunities, while refining geologic storage capacity estimates for the indicated reservoirs and flow units.



Core recovered from crystalline basement (contact at 1,712 feet).

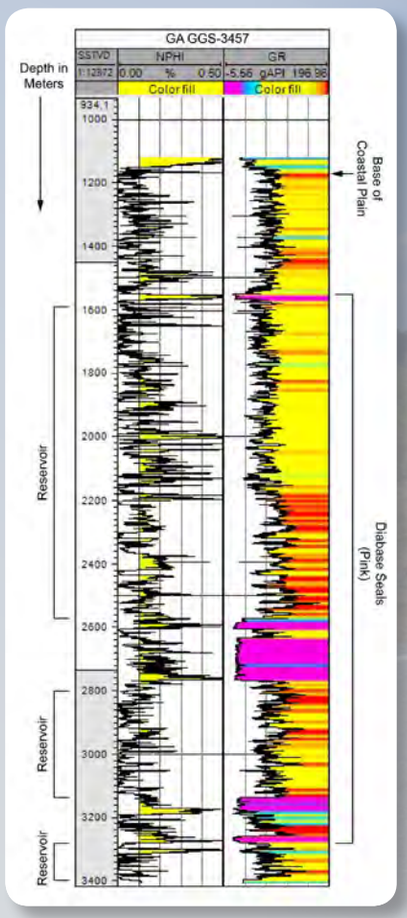
Background image: Trustees of Columbia University—Air hammer test rig at Lamont Doherty Test Well 4 (TW-4).

Geologic Characterization of the South Georgia Rift Basin for Source Proximal CO_2 Storage

The South Carolina Research Foundation and partners evaluated the feasibility of CCS in the Jurassic/Triassic (J/T_R) saline formations of the buried Mesozoic South Georgia Rift (SGR) Basin that extends from South Carolina into Georgia. The J/T_R sequence, based on preliminary assessment of limited geologic and geophysical data, appears to have both the appropriate areal extent and multiple horizons to permanently and safely store CO_2. The presence of several igneous rock layers within the sequence may potentially provide adequate seals to prevent upward CO_2 migration into the Coastal Plain aquifer systems.

Approximately 81 kilometers of 2-D seismic reflection data were collected by Bay Geophysical, Inc. to explore a portion of the SGR located in southern Georgia. The 81 kilometers were divided into two lines approximately 40.5 kilometers each, with Line 1 intersecting Georgia well GGS 3457. Line 2 intersects Line 1 at the southern portion of Line 1 to maximize the extent of coverage away from GGS-3457 (a deep well drilled in the 1980s for oil and gas exploration). This well had a set of usable logs, including gamma and neutron logs that provided promising results related to CO_2 storage. Results showed sandstone with porosity values greater than 10 percent and a thickness of 120 meters. The design of the seismic shot was to extrapolate information away from the well and to better define the extent of the SGR and the necessary reservoir and caprock for a successful CO_2 injection.

A numerical simulation model of CO_2 injection and migration was developed based on the geology log for the GGS-3457 well. The simulation model was used to investigate the feasibility of injecting 30 million metric tons of CO_2 into SGR J/T_R sediments and the integrity of the diabase layers as seals to prevent CO_2 migration.



Georgia GGS-3457 well log: This figure shows the geology log containing porosity (left) and natural gamma (right). The presence of several diabase layers that may act as seals for multiple CO_2 storage reservoirs in a stacked storage concept can be seen in this log. The zones highlighted in yellow have porosity values greater than 10 percent.

Background image: The 2-D seismic reflection acquisition by Bay Geophysical, Inc. was collected using two INOVA UNIVIB vibrator trucks along with a Wireless Seismic System, which greatly reduced acquisition time. The picture was taken along GA Line #1.

UNIVERSITY OF ALABAMA

Site Characterization for CO_2 Storage from Coal-fired Power Facilities in the Black Warrior Basin of Alabama

This project had two primary objectives: (1) quantify the ability of the saline formations and mature conventional hydrocarbon reservoirs to accept and retain CO_2 and (2) develop a site characterization, selection, and development plan to facilitate commercial utilization of these formations for CO_2 storage, including opportunities for enhanced oil/gas recovery. The Black Warrior Basin of Alabama contains two major coal-fired power plants that serve the Birmingham-Tuscaloosa economic corridor and emit more than 24 million metric tons of CO_2 to the atmosphere annually. The basin hosts diverse coal, coalbed methane, and conventional oil and natural gas resources. The basin has Gigaton-class CO_2 storage resource in an array of sandstone, limestone, and dolostone units of Cambrian through Pennsylvanian age. The assessed P_{50} (medium) resource of the Mississippian-Pennsylvanian formations is approximately 1,600 million metric tons, and that of the Cambrian through Devonian formations is approximately 1,300 million metric tons. Saline formations provide the greatest potential for long-term storage throughout the basin, and opportunities exist west of the plants in mature oil and gas fields, where miscible CO_2 flooding and pressure maintenance programs may prolong the life of the fields. Multiple seals of regional extent help protect the underground sources of drinking water (USDW).

The University of Alabama, the Geological Survey of Alabama, and Rice University, with the cooperation of Southern Company, SECARB, and Schlumberger Carbon Services, developed a characterization test site at the William C. Gorgas Electrical Generating Plant. Site characterization included drilling, logging, and coring the Gorgas #1 exploratory borehole; acquiring 10 miles of 2-D seismic data; quantifying and simulating storage resource and injectivity; and analyzing seal integrity and containment.

Estimated CO_2 Storage Resource of Paleozoic Strata in the Black Warrior Basin of Alabama

Formation	Age	Rock Types	P_{15} Resource (Mt) (low)	P_{50} Resource (Mt) (medium)	P_{85} Resource (Mt) (high)
Pottsville	Pennsylvanian	Sandstone	185	1,368	2,550
Parkwood	Mississippian-Pennsylvanian	Sandstone	21	151	282
Bangor	Mississippian	Limestone	3	24	44
Hartselle-Pride Mtn.	Mississippian	Sandstone	9	64	119
Tuscumbia	Mississippian	Limestone, Chert	19	141	263
Devonian undiff.	Devonian	Limestone, Chert, Sandstone	38	279	520
Red Mountain	Silurian	Limestone, Chert	41	302	564
Sequatchie	Ordovician	Limestone	9	69	129
Stones River	Ordovician	Limestone	22	162	301
Knox	Cambrian-Ordovician	Dolostone, Limestone, Sandstone	88	649	1,211
Total (Mt)			**435**	**3,209**	**5,983**
Years of Storage Resource*			**16**	**117**	**218**

** Estimate based on annual CO_2 emission of 27.45 Mt.*

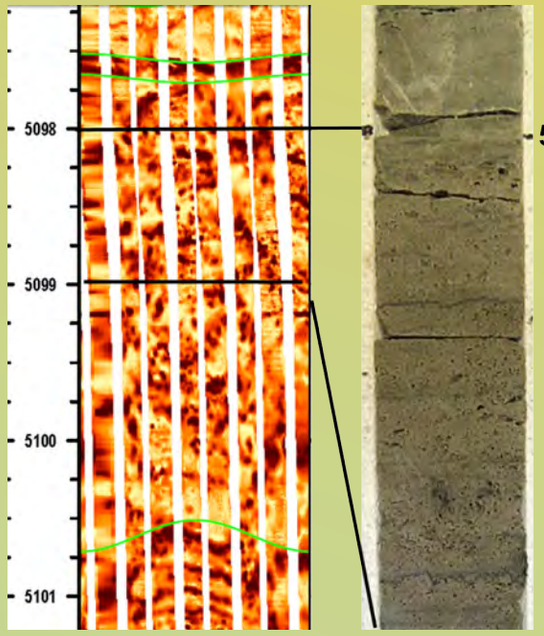
Background image: Vibroseis trucks acquiring geophysical data near Plant Gorgas in May 2011.

An Evaluation of the Carbon Sequestration Potential of the Cambro Ordovician Strata of the Illinois and Michigan Basins

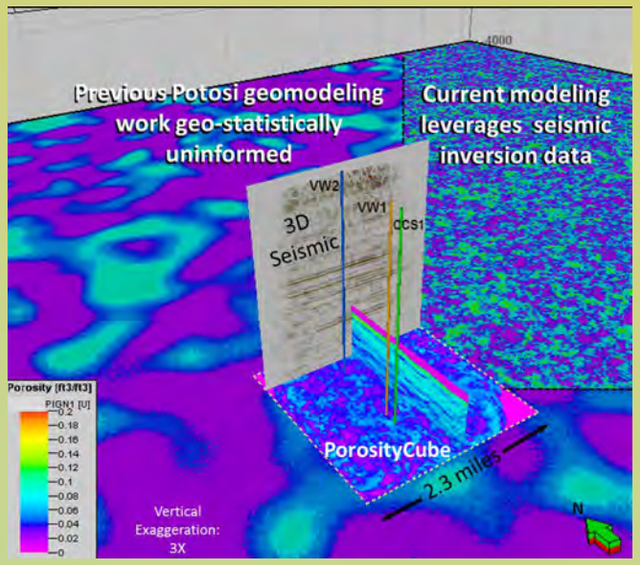
A consortium of State geological surveys from Illinois, Indiana, Kentucky, and Michigan, in collaboration with Brigham Young University and Schlumberger Carbon Services, investigated the CO_2 storage potential of the Cambrian-Ordovician strata that underlie portions of Illinois, Indiana, Michigan, and western Kentucky. This research helped to identify and characterize alternative reservoirs in regions where the underlying Mount Simon Sandstone may be inadequate for use as a CO_2 storage reservoir.

Geologic cross sections, maps, and 3-D geocellular models were developed to portray the regional-scale characteristics and spatial variability of the entire Cambrian-Ordovician strata in the Illinois and Michigan Basins and evaluate the geometries of the St. Peter Sandstone and Knox Supergroup units (e.g., Potosi Dolomite/Copper Ridge Group) in relation to the primary regional seal (Ordovician Maquoketa Group and Utica Shale) and potential secondary seals. Core samples collected for petrophysical analysis from wells in Illinois (ADM Verification Well #1) and Kentucky (Marvin Blan #1) provided information on the reservoirs' pore types and petrophysical properties on both regional and local scales. A database was developed for analyzing petrophysical results from core analyses and borehole geophysical logs throughout the region, allowing for improved resolution and reduced uncertainty in reservoir quality prediction in areas of high-quality well control.

With a combined thickness exceeding 500 meters (1,600 feet) throughout much of the study area, the St. Peter Sandstone and Knox Supergroup dolomites appear to be promising alternative targets for geologic CO_2 storage. Carbon dioxide storage resource estimates for the St. Peter Sandstone range from 0.6 to 6.1 billion metric tons in the Illinois Basin and 15.4 to 50.1 billion metric tons in the Michigan Basin. Analysis of the Knox Supergroup suggests a CO_2 storage resource in the Illinois Basin of 27 to 236 billion metric tons due to the thickness of the southern portion. Pilot-scale CO_2 injection tests in the Blan well indicate Knox Supergroup dolomites and sandstones are viable storage targets in the southern Illinois Basin. Topical reports and additional information are available from NETL and at the project website.



Compact Formation Micro Imager™ log and core from a deep test well in Hancock County, Kentucky, show significant vuggy-type porosity in the Knox Supergroup.



A comparison of Potosi Formation property distribution modeling efforts. Earlier work (left) was based on well logs and Gaussian simulations, whereas recent modeling (right) uses seismic inversion data (PorosityCube) as model input to estimate vugular zones and increased lateral heterogeneity. At center: three wells that penetrate the Potosi Formation in the context of 3-D seismic data and PorosityCube.

UNIVERSITY OF KANSAS

KU KANSAS GEOLOGICAL SURVEY
The University of Kansas

Modeling CO_2 Sequestration in a Saline Reservoir and Depleted Oil Reservoir to Evaluate the Regional CO_2 Sequestration Potential of the Ozark Plateau Aquifer System, South-Central Kansas

The midcontinent of the United States has a long history of oil exploration and production with a geologic setting that appears to be amenable to using CO_2 for EOR and long-term storage. The Kansas Geological Survey, a division of the University of Kansas, worked with industry and academic partners to study CO_2 storage potential within the Ozark Plateau Aquifer System using seismic, geologic, and engineering approaches. The study focused on the CO_2-EOR potential of a Mississippian cherty dolomite formation in the Wellington Field and storage in the underlying Cambro-Ordovician Arbuckle Group saline formation. A larger study spanned an area in south-central Kansas to evaluate the Arbuckle Group saline formation for CO_2 storage, as well as the Chester and Morrow sandstone formations for EOR suitability.

The project team acquired seismic, gravity, magnetic, and remote sensing data; cored and logged new wells; and analyzed and mapped stratigraphic horizons with CO_2-EOR and storage potential. The team also assessed structural and infrastructure elements that could affect storage permanence and developed models for CO_2 injection and migration analysis. The acquired data and results were released to an interactive map.

Integrated geologic models were constructed, and the project team performed reservoir simulation studies to estimate the CO_2 storage potential of multiple formations. The effort collected available historical data, drilled and logged three new wells through the Arbuckle Group, cored essentially all of the injection and confining zones in two of the new wells, and performed chemical and physical analyses on the samples. Reservoir simulations were conducted to determine injectivity and calculate the fraction of CO_2 stored in solution, as well as residual gas saturation and mineral precipitates. These simulation results and lab measurements help to determine the seal integrity needed to overcome the pressure increase from injection, evaluate seal porosity changes due to geochemical reactions, and identify any CO_2 release pathways.

Background image: Kansas Geological Survey investigators and Beredco drilling team inspect Arbuckle samples taken from the newly cored well during a visit to the Cutter KGS #1 site in Stevens County. The investigators recovered 2,469 feet of total core from two characterization wells in the study (1,042 feet in Cutter and 1,427 feet in Wellington). Additional photos and information are available from the project website

Gulf of Mexico Miocene CO_2 Site Characterization Mega Transect

The University of Texas at Austin study focused on (1) collecting high-resolution, 3-D (HR3D) seismic datasets of the shallow geologic section to evaluate the capacity of potential reservoirs and the sealing capacity of the confining system, and (2) producing a regional CO_2 atlas of Miocene age units of the upper Texas coast submerged lands (southeast Texas). The goal of the study was to evaluate the capability of the Miocene age geologic section of Texas submerged lands to permanently store large volumes of anthropogenic CO_2.

The geographic locations of three HR3D, "P-Cable" seismic surveys collected in the near-shore waters of southeast Texas are shown in Figure 1, while Figure 2 offers a vertical and horizontal view (data "cube") example from the second survey. The dataset's high quality allowed for defining recognizable geologic morphologies (shapes) and possible fluid content (Figure 3), which are important for determining an area's prospects for geologic storage.

The regional CO_2 atlas of Miocene age units highlights several topics, including: (1) a regional analyses of petroleum systems as analogs for CO_2 storage (Figure 4); (2) petrography, petrology, and extent of confining systems of the Miocene section; (3) static capacity estimate; and (4) examples of characterization methodologies of prospect areas. The HR3D datasets and regional analyses within the CO_2 atlas of the offshore Texas Miocene provide a sound basis for a future generation of specific CO_2 prospects in the study area.

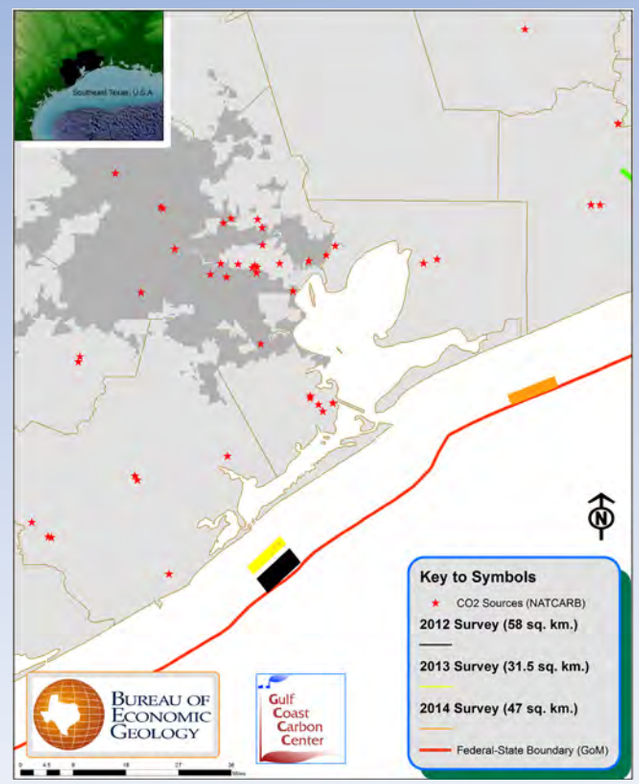


Figure 1. A map of the southeast Texas coastal region showing the locations of three HR3D (P-Cable) surveys collected by the study. The outline of the 2012 survey is shown in black, the 2013 survey in yellow, and the 2014 survey in orange. Note the outline of the city of Houston in dark gray and the boundary (red line) between State and Federal waters.

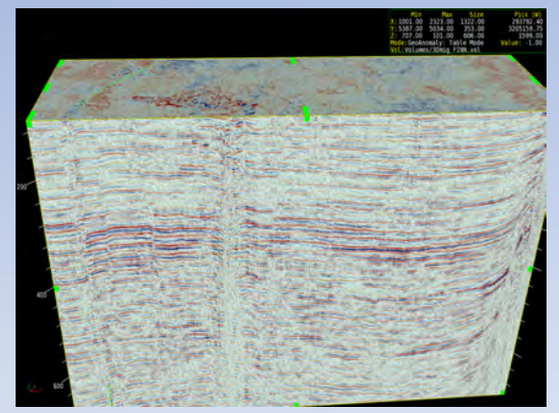


Figure 2. A 3-D representation ("cube") of an amplitude volume of the October, 2013, HR3D dataset. The upper surface of the volume is a time-slice at approximately 100 milliseconds (ms). The foreground is a vertical transect from approximately 100 to 700 ms.

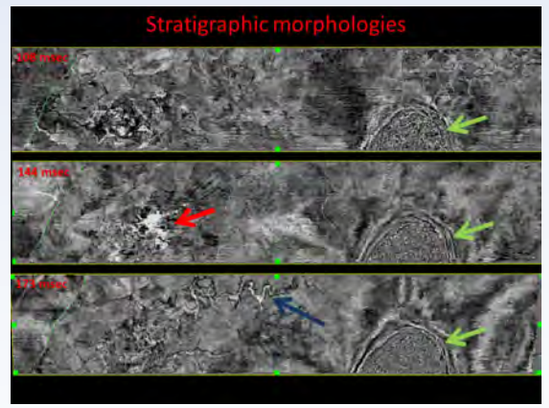


Figure 3. Slices in the time domain at 108, 144, and 173 ms, respectively, through the fully processed P-Cable dataset collected in October, 2013. The green arrows point to a well-defined salt diapir (dome). The blue arrow identifies a channel-like feature at 173 ms, and the thin green line on the left at each time-slice highlights a normal fault. The red arrow on the 144 ms time-slice identifies an area of very high amplitudes (bright white) that may indicate the presence of natural gas.

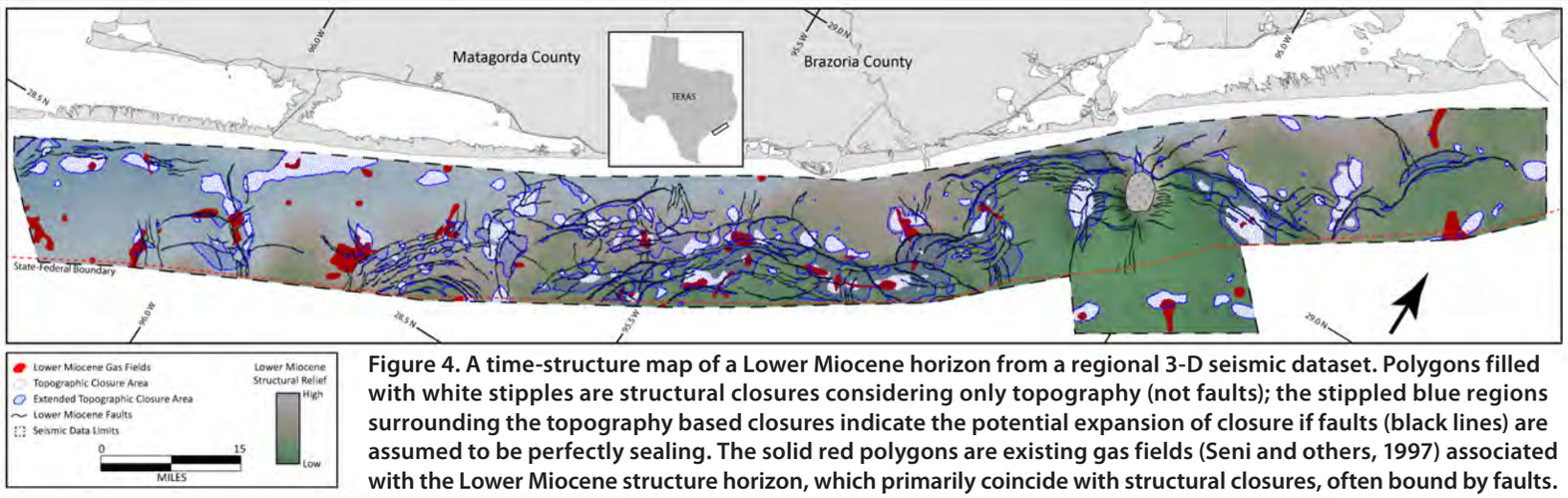


Figure 4. A time-structure map of a Lower Miocene horizon from a regional 3-D seismic dataset. Polygons filled with white stipples are structural closures considering only topography (not faults); the stippled blue regions surrounding the topography based closures indicate the potential expansion of closure if faults (black lines) are assumed to be perfectly sealing. The solid red polygons are existing gas fields (Seni and others, 1997) associated with the Lower Miocene structure horizon, which primarily coincide with structural closures, often bound by faults.

UNIVERSITY OF UTAH

Characterization of Most Promising Sequestration Formations in the Rocky Mountain Region

Introduction

The Rocky Mountain Carbon Capture and Storage (RMCCS) project investigated multiple geologic formations and characterized a local site on the Colorado Plateau for future CCS opportunities.

The RMCCS project focused on the Cretaceous Dakota, Jurassic Entrada, and Pennsylvanian Weber Sandstones, the three largest regional formations. All formations in this project are potential CO_2 storage resources for future power plants, natural gas processing plants, cement plants, and oil shale development projects.

Characterization

The area adjacent to Craig, Colorado, (Sand Wash Basin) was the area selected for detailed geologic characterization on the RMCCS project. The basin was selected in part because the geology can be extrapolated to other sites on the Colorado Plateau.

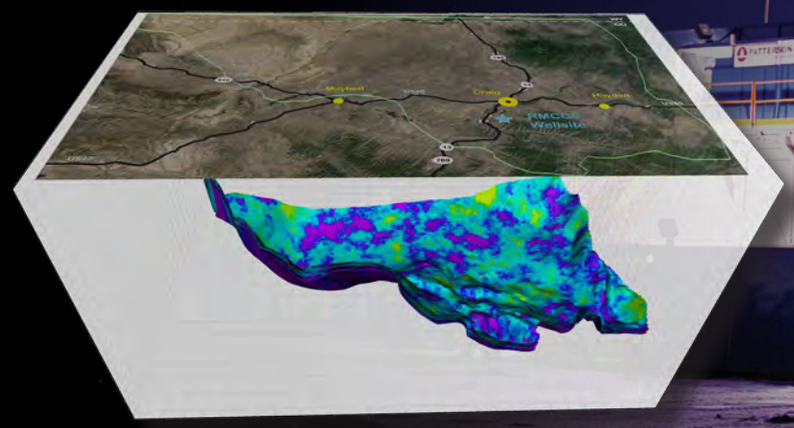
Field mapping and seismic surveys were conducted to identify and evaluate the basin's structural configuration. A 9,745-foot deep characterization well was drilled to collect 131 feet of core and a suite of geophysical well log data. Petrophysical tests on samples of core were used to calibrate geophysical log data, which can be used to obtain storage resource estimates and evaluate associated uncertainty as well as simulate the hydrologic behavior of injected CO_2.

Results - Regional

A detailed analysis of the primary formations (Dakota, Entrada and Weber sandstones) yielded a more accurate CO_2 storage resource assessment for these formations within the Colorado Plateau; RMCCS estimates indicate a total CO_2 storage resource of more than 38,000 million metric tons.

Results - Local

The characterization of the Sand Wash Basin (2-D seismic surveys, multiple well logs and lithological, petrophysical and geochemical analyses) allowed for a detailed 3-D model to be constructed. The model served as the framework for analyses ranging from CO_2 storage resource, injectivity, and subsurface flow to uncertainty estimates to evaluation of risk.



Sand Wash Basin Porosity Model.

Background image: RMCCS Craig drill rig at night. Photo source: Schlumberger Carbon Services.

UNIVERSITY OF WYOMING
Carbon Management Institute
Baker Hughes, Inc. • Los Alamos National Laboratory • Lawrence Livermore National Laboratory • Wyoming State Geological Survey
PetroArc International • New England Research • Geokinetics, Inc. • EMTEK, Inc. • Core Laboratories • True Drilling

Site Characterization of the Highest-Priority Geologic Formations for CO_2 Storage in Wyoming

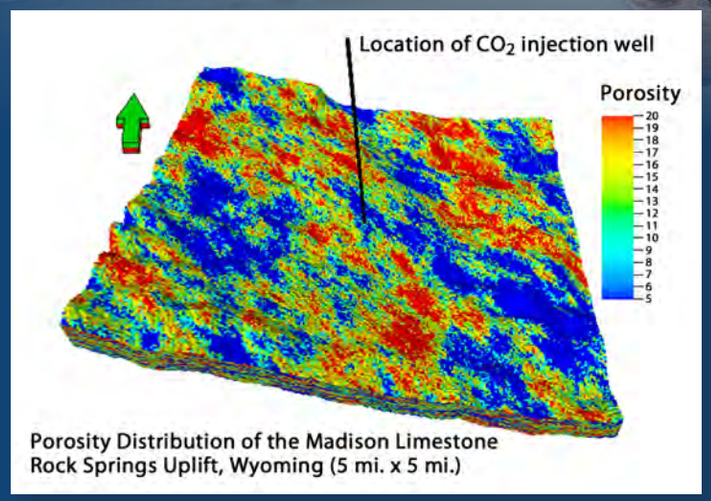
The Wyoming Carbon Underground Storage Project (WY-CUSP) consisted of CO_2 storage site characterization and evaluation, focusing on Wyoming's most promising CO_2 storage reservoirs (the Pennsylvanian Weber/Tensleep Sandstone and Mississippian Madison Limestone) and premier CO_2 storage site (Rock Springs Uplift). Results from the WY-CUSP project suggest the two reservoirs could store up to 17,000 million tons of CO_2.

The WY-CUSP team drilled a stratigraphic test well and acquired a 3-D seismic survey covering 25 square miles of the Rock Springs Uplift site. The team retrieved 916 feet of core from the 12,810-foot-deep well, along with a complete log suite, borehole images, fluid samples, and other data. Project partners (1) provided continuous visual documentation of the core, including grain size, mineralogy, facies distribution, and porosity; (2) performed continuous permeability and velocity scans of selected reservoir intervals; and (3) chemically analyzed the fluid samples. WY-CUSP scientists integrated seismic attributes with observations from log suites, a VSP survey, core, fluid samples, and laboratory analyses, including continuous permeability scans. From these integrations, researchers constructed 3-D spatial distribution volumes of reservoir and seal properties that represent geological heterogeneity at the targeted CO_2 storage site. The WY-CUSP team used this data to perform new CO_2 plume migration simulations.

Baker Hughes, Inc., completed a series of small-scale, in-situ water injectivity measurements. A database was formed when observations, analyses, and experiments from the stratigraphic test well were integrated. Correlation of these data allowed petrophysical parameters to be extrapolated from the test well out into the storage domain (5x5 mile 3-D seismic survey volume). This resulted in an improved, realistic understanding of performance assessments for potential CO_2 storage scenarios.

The WY-CUSP team worked on (1) improving CO_2 storage resource estimates, (2) establishing long-term integrity and permanence of confining layers, (3) designing a profitable strategy for pressure management, and (4) evaluating the utilization of stored CO_2 at the Rock Spring Uplift. Finally, Baker Hughes developed a microseismic baseline for the test site using in-bore geophones to complete field operations.

Background image: The rig used to drill the nearly 13,000-foot-deep WY-CUSP stratigraphic test well on the Rock Springs Uplift.



Porosity Distribution of the Madison Limestone
Rock Springs Uplift, Wyoming (5 mi. x 5 mi.)

Porosity distribution of Madison Limestone, inverted from 3-D seismic data (left). New data from well observations will allow the conversion from relative to real reservoir properties in three dimensions. (In legend black line indicates location of stratigraphic test well.)

Appendices

Appendix A: Summary of Methodology for Determining Stationary CO_2 Source Emissions

The EPA, as directed by statute[1], maintains the Greenhouse Gas Reporting Program (GHGRP). Data reporting began during calendar year 2010 (reported in 2011) and continued with 2011 and 2012 calendar years. Calendar year 2012 was published in September 2013 and serves as the basis for the NATCARB data provided to the Regional Carbon Sequestration Partnerships for use in the *Carbon Storage Atlas (5th edition) (Atlas V)*. In addition to production and importation of fossil fuels and industrial gases, the GHGRP provides annual GHG data, including location and other relevant information for large, stationary direct CO_2 equivalent (CO_2e) emission[2] sources in the United States[3]. For calendar year 2010, data were reported for four categories of stationary direct CO_2e emission sources and later increased to nine categories in 2011 and 2012 (Table 1). In 2012, total direct emissions in the 2012 EPA GHGRP database was 3,130 million metric tons CO_2e from 7,809 large stationary sources. This represents approximately one half of total U.S. GHG emissions. The current NATCARB database includes eight of the nine categories of direct CO_2e emission sources, which represent 3,030 million metric tons CO_2e from 6,198 large stationary sources (97 percent of the emissions reported by EPA in the GHGRP system). More information about EPA's GHGRP is **available online**.

The NATCARB data provided to the RCSPs consists of three sets: (1) the working version of the current NATCARB sources geodatabase (*Atlas IV*, v1303); (2) the 2011 EPA GHGRP database; and (3) the 2012 EPA GHGRP database. In addition, the NATCARB source working version includes emissions for large, stationary sources in western Canada provided by the RCSPs (primarily the PCOR Partnership). Canadian source data is derived primarily from Natural Resources Canada (NRCAN) (the year represented by the source data varies). All data in the NATCARB database indicates the vintage (year) and source (EPA, NRCAN, or appropriate RCSP). As part of *Atlas V* efforts, the RCSPs were tasked with evaluating source records to determine which source records should remain in the NATCARB sources layer.

Industry Sector	2010 GHGRP	2011 and 2012 GHGRP	*Atlas V* Sources
Power Plants	X	X	X
Petroleum and Natural Gas		X	X
Refineries	X	X	X
Chemical		X	X
Waste		X	
Metals/Industrial		X	X
Minerals	X	X	X
Pulp and Paper	X	X	
Other[4]		X	X

Work was undertaken to verify and correct the locations of the sources in the NATCARB sources database. A query was performed to select sources in a given State and Province based on source type. Source types from the current NATCARB database include: Petroleum/Natural Gas, Industrial, Refineries/Chemical, Power Plants, Unclassified, Ag Processing, Ethanol, Fertilizer, and Cement Plants. Each source type was verified for all States and Provinces in each RCSP before moving to the next source type. Appendix 1 provides a description of the source location verification procedures. The current NATCARB sources geodatabase uses the EPA GHGRP 2011 and 2012 data, but utilizes the verified coordinate locations. Appendix 2 provides a description of the structure of the NATCARB source databases.

Methodology for Location Verification of CO_2 Sources

Received Original File from RCSPs

Step 1: A query was performed on the shapefile to select sources based on source type.

- Source Types: Petroleum/Natural Gas, Industrial, Refineries/Chemical, Electricity, Unclassified, Ag Processing, Ethanol, Fertilizer, Cement Plant.
- Each source type was verified for all States and Provinces before moving on to the next source type.

Step 2: Once a source type was selected, a query was performed on the shapefile to select individual States and Provinces.

- Each source was verified in the State or Province before moving on to the next State. Once all States were verified, the next source type was selected.
- This process was recorded in a Microsoft Excel spreadsheet to ensure all States and sources were verified.
- Note that all RCSPs were verified with the exception of the PCOR Partnership.

Step 3: Each feature point was visually located on aerial imagery/street map layer and searched for corresponding infrastructure.

If corresponding infrastructure was found and matched to point:

- Infrastructure was checked to ensure address given in shapefile matched location.
- If address and infrastructure matched corresponding point, the location of the source was considered verified.
- If address and infrastructure did not match, a web search was performed to verify the address. If a new address was found, it was noted in the shapefile.

[1] Consolidated Appropriation Act (H.R. 2764: Public Law 110-161).

[2] CO_2e GHGs include carbon dioxide, methane, nitrous oxide, and fluorinated gas.

[3] Stationary facilities that emit 25,000 metric tons of CO_2 equivalent or more per year are included in the GHGRP.

[4] NATCARB breaks out EPA "Other" source type into Ethanol, Fertilizer, Cement, Ag Processing, and Unclassified.

- Confirmation was based on visual infrastructure and address proximity to feature point.
- If any information did not correspond, it was noted in the shapefile.

If infrastructure was not found at corresponding point:

- The corresponding address was located to see if infrastructure could be matched at address location.
- If address location and infrastructure matched, but the point was located elsewhere, the feature point was moved to the corresponding infrastructure and address location (Step 2). A web search was then used to verify location if the location was still in question. Any inconsistencies were noted in the shapefile.
- If infrastructure, address location, and feature point did not match, a web search was performed to obtain additional location information, including additional addresses or imagery that depicted the source that could be used to verify on aerial imagery. In addition, Google Earth™ and Google Maps™ were used to verify infrastructure when possible.

Step 4: Feature point moved to correct location, if necessary.

- If feature point was determined to be in the wrong location in Step 1 (based on visual and address verification), the point was moved to the verified location. This was noted in the shapefile for each moved point.
- If the feature point could not be verified, it was not moved. This was noted in the shapefile.

Step 5: Once the location of each point was verified, each point was assigned a unique EPA Source ID, if possible.

- An Excel file with GHGRP ID for CO_2 sources was used as the basis for creating an EPA Source ID.
- There were no matching unique fields between the GHGRP ID Excel file and the CO_2 sources shapefile. Therefore, a field was created in each file that linked the "Source Name" and "Address" fields.
- Once the shapefile and Excel file had a mutual field in common (SourceNameAddress), the files were joined in ArcMap. All exact matching records were noted.
- The remaining unmatched records then underwent a manual matching process.
  - Each unmatched feature point in the shapefile was compared to similar named features in the Excel file. Where address and location data was the same, the feature point was matched. If no address data was available or if there were inconsistencies in address data, a web search was performed to ensure the most up-to-date data was obtained.
  - If any inconsistency was noted, the feature point was not matched and an EPA Source ID was not given.
  - If a feature point was matched, the GHGRP ID number was manually entered for that feature point.
- It should be noted that a number of CO_2 feature points had the same location and IDs, but alternate emissions. These were the same facility and referred to the same infrastructure, but were listed separately due to their varying emissions. This was noted in the shapefile with the following comment:
  - "Duplicate feature with alternative emissions given same EPA SOURCE ID."

Step 6: Once all possible matches were made, a new field was populated in the shapefile for the EPA Source ID, which linked the EPA ID and the GHGRP ID fields.

Step 7: Cleanup

- The shapefile was checked to ensure that the number of fields and field names matched the original file from the RCSPs. The only additional field was the "EPA SOURCE ID" field.

Structure of NATCARB Sources Geodatabases

The NATCARB sources data package contains three sets of data: (1) the working version of the current NATCARB Sources layer (*Atlas IV*, v1303); (2) the 2011 EPA GHGRP database; and (3) the 2012 EPA GHGRP database. Work was done to verify and correct the locations of sources in the NATCARB sources database. However, because the unique ID for EPA sources (GHGRP_ID) was not available at the time the *Atlas IV* sources layer was compiled, the GHGRP_ID was added after the fact. Due to some mismatches in facility names and temporal differences of the datasets (*Atlas IV* Sources are based on 2010 EPA data), some NATCARB sources could not be assigned a GHGRP_ID. One of the primary tasks for *Atlas V* was to evaluate these unmatched records in cooperation with the RCSPs and determine if they should remain in the NATCARB sources layer.

The basis for the *Atlas V* sources has been created: EPA_NC_VER_2011 and EPA_NC_VER_2012. These point layers contain the EPA attributes, but utilize the verified coordinate locations from the *Atlas IV* NATCARB sources layer where UNMATCHED = 0 (i.e., records match between databases). The longitude and latitude (WGS84) coordinates were calculated into the LONGITUDE_WGS84 and LATITUDE_WGS84 fields, respectively. Where UNMATCHED = 1, no NATCARB source was found and the coordinates are those from the EPA.

Projection of the sources layer should be Geographic WGS 84 (**GCS_WGS_1984**).

The .zip file **For_RCSPs_Sources_120613.zip** contains the following files:

EPA_Sources.gdb

EPA_NC_VER_2011—point layer of all GHG Direct Emitters that had CO_2 emissions in 2011, updated with locations from *Atlas IV* where UNMATCHED = 0

EPA_NC_VER_2012—point layer of all GHG Direct Emitters that had CO_2 emissions in 2012, updated with locations from *Atlas IV* where UNMATCHED = 0

GHG_2011_CO2_Complete—table of all GHG Direct Emitters in 2011 (includes other GHGs)

GHG_2012_CO2_Complete—table of all GHG Direct Emitters in 2012 (includes other GHGs)

NATCARB_Sources.gdb

Sources_112613—working version of current release (*Atlas IV*, v1303) of NATCARB Sources

Ghgp_data_2011_09012013.xlsx—complete 2011 EPA GHG database downloaded from EPA

Ghgp_data_2012_09012013.xlsx—complete 2012 EPA GHG database downloaded from EPA

Unique ID—The fields **FACILITY_ID** (or **GHGRP_ID)** are the unique ID number assigned by EPA for each facility. These fields should be used to relate the EPA tables to the NATCARB sources layer. While all records in the EPA tables have a unique FACILITY_ID, not all records in the NATCARB Sources layer are populated for the GHGRP_ID field (see below).

Unmatched Records—The fields **UNMATCHED_<year>** in the NATCARB Sources layer and **UNMATCHED** in the EPA tables indicate records that could not be matched between the two databases (**UNMATCHED** = 1). Unmatched records can be a result of several factors: (1) difference in the names of the facilities (or other identifying attributes) thus preventing a match; (2) a facility emitted CO_2 in 2010, but did not in 2011 or 2012 (or vice versa); (3) the facility is not tracked by EPA; and/or (4) the facility is not in the United States.

CO_2 emissions—the EPA sources tables contain three columns with CO_2 emissions:

CO2_<year>—total non-biogenic CO_2 emissions.

CO2_BIOGENIC_<year>—total biogenic CO_2 emissions.

Total_CO2_eq_<year>—actual CO_2 emissions plus other GHG gases like sulfur hexafluoride (SF_6), nitrous oxide (N_2O), etc. (excludes biogenic emissions).

Appendix B: Summary of Methodologies Used to Estimate CO_2 Storage Resource

The methodologies derived for estimating geologic storage potential for CO_2 consist of widely accepted assumptions about in-situ fluid distributions in porous formations and fluid displacement processes commonly applied in the petroleum and groundwater science fields. These methodologies are described in detail in Goodman et. al. (2011). The volumetric approach is the basis for CO_2 resource calculations for saline and coal storage formations. The production approach is utilized for oil and gas storage formations where production data is available, with the volumetric approach used for storage formations when production data is not available.

The volumetric methods require the area of the target formation or horizon along with the formation's thickness and porosity. There are other specific parameters unique to oil and gas fields and coal seams that are needed to compute the estimated CO_2 storage resource. Because not all of the pore space within any given geologic formation will be available or amenable to CO_2, a storage coefficient (referred to as the efficiency- or E-factor) is applied to the theoretical maximum volume in an effort to determine what fraction of the pore space can effectively store CO_2. Efficiency is the multiplicative combination of volumetric parameters that reflect the portion of a basin's or region's total pore volume that CO_2 is expected to contact. For example, the CO_2 storage efficiency factor for saline formations (Esaline) has several components that reflect different physical barriers that inhibit CO_2 from contacting 100 percent of the pore volume of a given basin or region.

Ranges of values for the E-factor have been calculated for deep saline formations from statistical approaches that consider the variation in geologic properties encountered in subsurface target formations. The E-factor values for a particular injection horizon can be modified if more specific information about the formation is known, resulting in more precise resource estimations. In situations where this approach is taken, additional metadata is included in NATCARB to explain why the default numbers were not employed.

Carbon Dioxide Storage Resource Estimate Calculation Summary

A CO_2 resource estimate is defined as the volume of porous and permeable sedimentary rocks available for CO_2 storage and accessible to injected CO_2 via drilled and completed wellbores. Carbon dioxide resource assessments do not include economic or regulatory constraints; only physical constraints to define the accessible part of the subsurface are applied. In the following equations, the symbol GCO_2 refers to the mass of CO_2 that would be stored in the respective geologic medium, A refers to area, and h refers to thickness. The following are brief descriptions of the formulas used in calculating CO_2 storage resource estimations.

Computing CO_2 Resource Estimate—Oil and Natural Gas Reservoirs Volumetric Method. The general form of the volumetric equation being used for oil and natural gas reservoirs in this assessment is as follows:

$$G_{CO2} = A\, h_n\, f_e\, (1\text{-}S_w) B\, \rho\, E_{oil/gas} \quad \text{[Eq. 1]}$$

The reservoir area (A), its net thickness (h_n), and its average effective porosity (f_e) terms account for the total volume of pore space. The oil and gas saturation (1-water saturation as a fraction [S_w]) and formation volume factor (B) terms account for the pore volume available for CO_2 storage, and CO_2 density (ρ) transforms the pore volume into mass at the reservoir in-situ conditions of temperature and pressure. The CO_2 storage efficiency factor ($E_{oil/gas}$) reflects the fraction of the total pore volume of the oil or gas reservoir that can be filled by CO_2. An efficiency factor is derived from local experience or reservoir simulations.

Computing CO_2 Resource Estimate—Oil and Natural Gas Reservoirs Production Method. A production-based CO_2 storage resource estimate is possible if acceptable records are available on volumes of oil and gas produced. Produced water and injected water (waterflooding) are not considered in the regional estimate. In cases where a field has not reached a mature stage, it is beneficial to apply decline curve analysis to better approximate the estimated ultimate recovery, which represents the expected volume of produced oil and gas.

It is necessary to apply an appropriate reservoir volume factor (B) to convert surface oil and gas volumes (reported as production) to subsurface volumes (including correction of solution gas volumes if gas production in an oil reservoir is included). No area, column height, porosity, residual water saturation, or estimation of the fraction of original oil in place that is accessible to CO_2 is required because production reflects these reservoir characteristics. If information is available, it is possible to apply efficiency to production data to convert them to CO_2 storage volumes; otherwise replacement of produce oil and gas by CO_2 on a volume-for-volume basis (at reservoir pressure and temperature) may be acceptable.

Computing CO_2 Resource Estimate—Saline Formations. The volumetric equation for CO_2 storage resource estimate potential in saline formations is as follows:

$$G_{CO2} = A_t\, h_g\, f_{tot}\, \rho E_{saline} \quad \text{[Eq. 2]}$$

The total area (A_t), gross formation thickness (h_g), and total porosity (f_{tot}) terms account for the total volume of pore space available. The CO_2 density (ρ) term transforms pore volume into the CO_2 mass that can fit into the formation volume at in-situ conditions of temperature and pressure. The storage efficiency factor (E_{saline}) reflects the fraction of the total pore volume of the saline formation that will be occupied by the injected CO_2. E_{saline} factors for the P_{10}, P_{50}, and P_{90} percent confidence intervals are 0.51 percent, 2.0 percent, and 5.5 percent, respectively.

APPENDIX B

Computing CO_2 Resource Estimate—Unmineable Coal. The volumetric equation for CO_2 storage resource estimate potential in unmineable coal is as follows:

$$G_{CO2} = A\, h_g\, C_s\, r_{s,\,max}\, E_{coal} \quad \text{[Eq. 3]}$$

The total area (A) and gross seam thickness (h_g) terms account for the total volume of coal available. The fraction of adsorbed CO_2 (C_s) and CO_2 density ($r_{s,\,max}$) terms account for the mass of CO_2 that would be stored by adsorption in the respective volume of coal at maximum CO_2 saturation. The term C_s must consider coal density, CO_2 adsorption capacity (volume of CO_2 adsorbed per unit of coal mass) and coal moisture and ash content. The density of CO_2 in Eq. 3 is that at standard conditions of temperature and pressure ($\rho_{s,\,max} = 1.87\ kg/m^3$). The storage efficiency factor (E_{coal}) reflects the fraction of the total pore volume that will be occupied by the injected CO_2. E_{coal} factors for the P_{10}, P_{50}, and P_{90} percent confidence intervals are 21 percent, 37 percent, and 48 percent, respectively.

The assessments presented are intended to identify the general geographic distribution of CO_2 storage resources. The assessments are not intended to provide site-specific information for a company to select a site to build a new power plant or to drill a well. This resource estimation is based on physically accessible CO_2 storage in specific formations in sedimentary basins without consideration of injection rates, regulations, economics, or surface land usage. (Please note that not all RCSPs use the methodologies presented in Appendix B to generate saline formation, oil and natural gas reservoir , and/or unmineable coal CO_2 storage resource estimates.) A summary of the national CO_2 storage resource estimates appears in the "National Perspectives" section of *Atlas V*. Regional details of those CO_2 storage resource estimates are available via the NATCARB Viewer. Please note that a full CO_2 storage resource methodology update will be undertaken for the sixth edition of the *Carbon Storage Atlas (Atlas VI)*.

Background image: Scaffolding begins to come off of CO_2 and hydrogen sulfide absorbers at the Kemper County Energy Facility, October 2014. All rights reserved by Mississippi Power's Kemper County Energy Facility.

APPENDIX C

CO_2 Stationary Source Emissions and CO_2 Storage Resource Estimates Summary

This table ("CO_2 Emissions and Geologic Storage Resource Summary") is a compilation of all data provided in *Atlas V*. The States/Provinces with a "zero" represent estimates of minimal CO_2 storage resource, while States/Provinces with a blank represent areas that the RCSPs have not yet assessed.

Please note CO_2 geologic storage information in *Atlas V* was developed to provide a high-level overview of CO_2 geologic storage potential. Carbon dioxide resource estimates presented are intended to be used as an initial assessment of potential geologic storage. This information provides CCS project developers a starting point for further investigation of the extent to which geologic CO_2 storage is feasible. This information is not intended as a substitute for site-specific characterization, assessment, and testing. Please refer all NATCARB map and data requests to natcarb.maps@netl.doe.gov.

CO_2 Stationary Source Emissions and CO_2 Storage Resource Estimates Summary*

State/ Province	CO_2 Emissions		Oil and Natural Gas Reservoirs Storage Resource			Unmineable Coal Storage Resource			Saline Formation Storage Resource			Total Storage Resource		
			Billion Metric Tons			Billion Metric Tons			Billion Metric Tons			Billion Metric Tons		
	Million Metric Tons Per Year	Number of Sources	Low Estimate	Medium Estimate	High Estimate	Low Estimate	Medium Estimate	High Estimate	Low Estimate	Medium Estimate	High Estimate	Low Estimate	Medium Estimate	High Estimate
Alabama	91	134	0.06	.09	0.12	1.92	2.98	4.37	120.22	307.34	689.67	122.20	310.41	694.16
Alaska	18	63				8.64	13.44	19.75				8.64	13.44	19.75
Alberta	137	182	0.60	1.49	3.57	0.03	0.03	0.03	38.17	76.74	140.30	38.80	78.26	143.90
Arizona	57	67	0.00	0.00	0.01	0.00	0.00	0.00	0.11	0.42	1.14	0.11	0.42	1.15
Arkansas	44	120	0.11	0.18	0.25	1.58	2.46	3.61	4.38	21.20	59.84	6.07	23.84	63.70
British Columbia	17	71	0.00	0.00	0.00				0.88	1.87	3.58	0.88	1.87	3.58
California	106	374	3.56	4.85	6.63				30.33	147.55	417.07	33.89	152.40	423.70
Canadian Federal Offshore									0.96	4.65	13.15	0.96	4.65	13.15
Colorado	49	142	1.31	2.35	2.66	0.49	0.65	0.86	33.48	131.11	353.82	35.28	134.11	357.34
Connecticut	8	47												
Delaware	9	18							0.04	0.04	0.04	0.04	0.04	0.04
District of Columbia	0	6												
Florida	120	142	0.02	0.03	0.05	1.26	1.95	2.85	101.37	246.45	552.05	102.65	248.43	554.95
Georgia	69	120				0.01	0.02	0.03	145.33	148.70	159.02	145.34	148.72	159.05
Hawaii	8	23												
Idaho	3	39							0.04	0.15	0.39	0.04	0.15	0.39
Illinois	120	231	0.10	0.20	0.34	1.45	2.38	2.87	19.68	80.75	213.07	21.23	83.33	216.28
Indiana	149	180	0.02	0.04	0.07	0.09	0.14	0.17	38.14	66.67	128.52	38.25	66.85	128.76
Iowa	68	143				0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	0.01
Kansas	42	116	1.25	1.25	1.25	0.00	0.00	0.01	9.63	34.40	85.08	10.88	35.65	86.34
Kentucky	99	122	1.05	1.75	3.21	0.14	0.18	0.20	14.72	46.43	110.20	15.91	48.36	113.61
Louisiana	126	282	3.12	5.70	8.29	8.30	12.89	18.91	151.36	734.55	2075.23	162.78	753.14	2102.43
Maine	4	28										0.00	0.00	0.00
Manitoba	2	11	0.01	0.03	0.07				6.95	13.14	22.53	6.96	13.17	22.60
Maryland	24	52	0.00	0.00	0.00	0.00	0.00	0.00	1.86	1.88	1.93	1.86	1.88	1.93
Massachusetts	15	76										0.00	0.00	0.00
Michigan	87	208	0.17	0.26	0.32	0.00	0.00	0.00	31.55	45.56	66.20	31.72	45.82	66.52
Minnesota	46	130							0.00	0.00	0.00	0.00	0.00	0.00
Mississippi	34	91	0.28	0.45	0.62	5.44	8.46	12.45	139.02	459.15	1172.03	144.74	468.06	1185.10
Missouri	95	104	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.10	0.29	0.02	0.11	0.30
Montana	21	31	0.15	0.38	0.90	0.33	0.33	0.33	98.21	335.74	856.92	98.69	336.45	858.15
Nebraska	37	72	0.01	0.03	0.07	0.00	0.00	0.00	23.65	54.47	111.91	23.66	54.50	111.98

* States/Provinces with a "zero" value represent estimates of minimal CO_2 storage resource, while States/Provinces with a blank represent areas that have not yet been assessed by the RCSPs. Medium = p50. (*ATLAS V*1.1 DATA)

APPENDIX C

State/ Province	CO_2 Emissions		Oil and Natural Gas Reservoirs Storage Resource			Unmineable Coal Storage Resource			Saline Formation Storage Resource			Total Storage Resource		
	Million Metric Tons Per Year	Number of Sources	Billion Metric Tons			Billion Metric Tons			Billion Metric Tons			Billion Metric Tons		
			Low Estimate	Medium Estimate	High Estimate	Low Estimate	Medium Estimate	High Estimate	Low Estimate	Medium Estimate	High Estimate	Low Estimate	Medium Estimate	High Estimate
Nevada	18	37												
New Brunswick	0	0												
New Hampshire	4	16												
New Jersey	22	96							0.00	0.00	0.00	0.00	0.00	0.00
New Mexico	37	84	9.71	9.71	9.71	0.08	0.16	0.30	32.97	129.29	349.08	42.76	139.16	359.09
New York	43	203	0.05	0.08	0.15				4.37	4.37	4.37	4.42	4.45	4.52
Newfoundland & Labrador	0	0												
North Carolina	62	99							1.34	6.51	18.39	1.34	6.51	18.39
North Dakota	39	48	0.37	0.91	2.19	0.54	0.54	0.54	71.94	136.50	234.71	72.85	137.95	237.44
Northwest Territories	0	0												
Nova Scotia	0	0												
Ohio	126	231	0.65	1.08	1.97	0.12	0.12	0.12	9.91	9.91	9.91	10.68	11.11	12.00
Oklahoma	67	151	3.48	4.40	4.40	0.00	0.00	0.01	19.64	76.87	207.24	23.12	81.27	211.65
Ontario	0	0							0.01	0.01	0.01	0.01	0.01	0.01
Oregon	9	47							6.81	33.15	93.70	6.81	33.15	93.70
Pennsylvania	132	281	0.80	1.34	2.45	0.27	0.27	0.27	17.34	17.34	17.34	18.41	18.95	20.06
Puerto Rico	17	23												
Quebec	0	0												
Rhode Island	4	12												
Saskatchewan	24	41	0.38	0.96	2.31				149.72	285.22	492.63	150.10	286.18	494.94
South Carolina	41	77							30.10	31.07	34.18	30.10	31.07	34.18
South Dakota	9	33	0.00	0.00	0.01				3.70	7.04	12.15	3.70	7.04	12.16
Tennessee	50	90	0.00	0.00	0.00	0.00	0.00	0.00	0.50	1.85	4.63	0.50	1.85	4.63
Texas	376	677	133.72	137.60	141.48	14.02	21.80	32.03	331.62	1505.79	4199.74	479.36	1665.19	4373.25
U.S. Federal Offshore	5	87	17.18	17.18	17.18	1.69	2.63	3.86	472.06	2277.24	6432.96	490.93	2297.05	6454.00
Utah	38	73	1.31	2.39	2.66	0.03	0.07	0.12	22.61	88.65	239.35	23.95	91.11	242.13
Vermont	0	6												
Virginia	35	111	0.00	0.01	0.01	0.16	0.37	0.69	0.27	0.86	2.21	0.43	1.24	2.91
Washington	17	74				0.59	0.92	1.35	36.03	175.26	495.39	36.62	176.18	496.74
West Virginia	71	84	5.93	9.84	18.05	0.37	0.37	0.37	11.19	11.19	11.19	17.49	21.40	29.61
Wisconsin	54	134							0.00	0.00	0.00	0.00	0.00	0.00
Wyoming	66	118	0.23	0.59	1.41	6.55	6.64	6.78	146.34	570.92	1539.56	153.12	578.15	1547.75
North America Total	3,071	6,358	186	205	232	54	80	113	2,379	8,328	21,633	2,618	8,613	21,978

* States/Provinces with a "zero" value represent estimates of minimal CO_2 storage resource, while States/Provinces with a blank represent areas that have not yet been assessed by the RCSPs. Medium = p50. (*ATLAS V*1.1 DATA)

Background image: Drilling operations at Plant Gorgas for the University of Alabama site characterization project.

Carbon Storage Program Publications

NETL's Carbon Storage Program website (http://www.netl.doe.gov/research/coal/carbon-storage) offers extensive information about the program's components. The website provides an extensive program overview with details about Core Storage R&D, Storage Infrastructure, and Strategic Program Support; NATCARB capabilities; an FAQ information portal, information about the small- and large-scale field projects and site characterization projects; and an extensive publication database.

The publication database available on the Carbon Storage Publications webpage has a variety of documents posted for easy access to current information, including:

- The Carbon Storage Newsletter
- Carbon Storage Educational Resources
- Program Overview Presentations
- Program Reports, Plans, and Roadmaps
- Conference Proceedings
- Carbon Storage Portfolio
- Systems Analysis
- Peer Review
- Best Practice Manuals
- Fossil Energy Techlines

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