U.S. Department of Energy • Office of Fossil Energy
National Energy Technology Laboratory

Carbon Sequestration Atlas of the United States and Canada

2008




NETL

Second Edition

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Foreword

The Department of Energy's (DOE's) Office of Fossil Energy National Energy Technology Laboratory (NETL) is proud to release the second edition of the *Carbon Sequestration Atlas of the United States and Canada (Atlas II)*. Production of this Atlas is the result of cooperation and coordination among carbon sequestration experts from local, state, and federal agencies, as well as industry and academia. *Atlas II* provides a coordinated update of carbon capture and storage (CCS) potential across the majority of the U.S. and portions of Canada. The primary purpose of *Atlas II* is to update the carbon dioxide (CO_2) storage portfolio, document differences in CO_2 storage resource and CO_2 capacity, and provide updated information on the Regional Carbon Sequestration Partnerships (RCSPs) field activities. In addition, this Atlas provides an introduction to the carbon storage (sequestration) process and summarizes the DOE's Carbon Sequestration Program. It also presents updated information on the location of stationary CO_2 emission sources and the locations and storage potential of various geologic sequestration sites, and provides information about the commercialization opportunities for CCS technologies from each RCSP.

A key aspect of CCS is the amount of carbon storage potential available to effectively help address global climate change. As shown in this Atlas, CCS holds great promise as part of a portfolio of technologies that enables the U.S. and the rest of the world to effectively address climate change while meeting the energy demands of an ever increasing global population. This Atlas includes the most current and best available estimates of potential CO_2 storage resources determined by a methodology applied consistently across all of the RCSPs. A CO_2 **storage 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 storage resource assessments do not include economic or regulatory constraints; only physical and chemical constraints to define the accessible part of the subsurface are applied. Economic and regulatory constraints are included in geologic CO_2 capacity estimates. Under the most favorable economic and regulatory scenarios, 100 percent of the estimated CO_2 storage resource may be considered CO_2 capacity. The RCSPs have documented the location of more than 4,600 stationary sources with total annual emissions of over 3,200 million metric tons of CO_2. With a total estimated CO_2 storage resource over 3,500 billion metric tons in oil and gas reservoirs, coal seams, and saline formations, preliminary estimates suggest over 1,100 years of CO_2 storage in geologic formations in the U.S. and portions of Canada.

All data in *Atlas II* were collected before June 2008. It is acknowledged that these data sets are not comprehensive; it is, however, anticipated that CO_2 storage resource estimates as well as geologic formation maps will be updated every 2 years as new data are acquired and methodologies for CO_2 storage estimates improve. Further, it is expected that, through the ongoing work of the RCSPs, data quality and conceptual understanding of the CCS process will improve, resulting in more refined CO_2 storage estimates.

About this Atlas

The second edition of the *Carbon Sequestration Atlas of the United States and Canada* contains three main sections: (1) Introduction, (2) National Perspectives, and (3) Regional Perspectives. The Introduction section contains an overview of CCS technologies, a summary of the DOE's efforts in the CCS area, a brief description of the RCSP Program, and information on the National Carbon Sequestration Database and Geographic Information System (NATCARB). The National Perspectives section provides maps showing the number, location, and magnitude of identified CO_2 stationary sources in the U.S. and portions of Canada, as well as the areal extent and estimated CO_2 storage resource available in geologic formations evaluated within the RCSP Regions. The National Perspectives section also contains a summary of the methodologies and assumptions employed to calculate CO_2 emissions and estimated CO_2 storage resource of various geologic formations. The Regional Perspectives section includes a detailed presentation of CO_2 stationary sources, CO_2 storage resource assessments, updates on field projects, and information on commercialization opportunities in each RCSP based on these methodologies and assumptions.

The U.S. Department of Energy and the National Energy Technology Laboratory would like to acknowledge all who have contributed to this *Altas*.

Contents

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The Greenhouse Gas Effect

Greenhouse gases (GHGs) are gas phase components of the atmosphere that contribute to the greenhouse gas effect, the trapping of radiant heat from the sun within the Earth's atmosphere. One GHG of particular interest is carbon dioxide (CO_2) because it is one of the most prevalent of all GHGs. Carbon dioxide is a colorless, odorless, nonflammable gas. Atmospheric CO_2 originates from both natural and man-made sources. There are multiple natural sources of CO_2, including volcanic outgassing, the combustion and decay of organic matter, and the respiration processes of organisms. Man-made, or anthropogenic, sources of CO_2 are primarily the burning of various fossil fuels for power generation and transportation, although other industrial activities contribute to atmospheric CO_2 concentrations as well.

The GHG effect is a natural and important phenomenon of the Earth's ecosystem. However, GHG levels in the atmosphere have significantly increased above the pre-industrial level according to the Energy Information Administration (EIA). Emissions of CO_2 from human activity have increased from an insignificant level two centuries ago to annual emissions of over 28 billion metric tons (31 billion tons) worldwide today. This increase in atmospheric GHGs is considered by many scientists to be a contributing factor to the phenomenon of global warming and a potential cause of unwelcome shifts in regional climates.

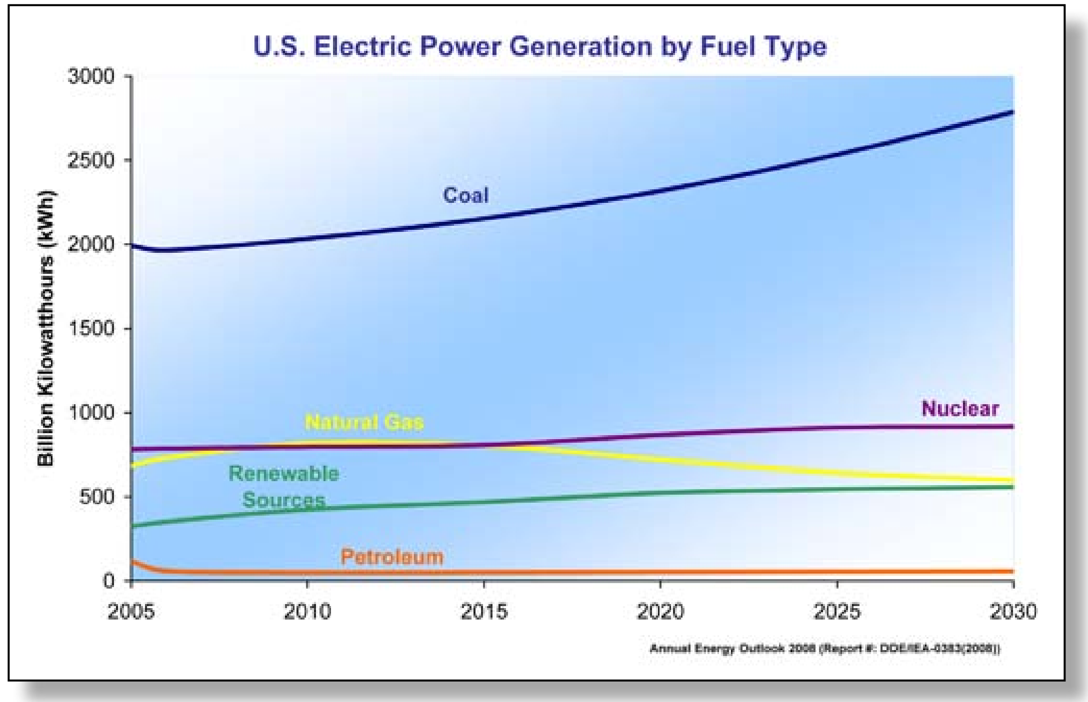
The U.S. is one of 192 countries that are signatories to the United Nations Framework Convention on Climate Change (UNFCC), a treaty approved in 1992 which calls for stabilization of atmospheric GHGs at a level that would prevent anthropogenic interference with the world's climate. Conservation, renewable energy, and improvements in the efficiency of power plants, automobiles, and other energy-consuming devices are important first steps in any GHG emissions mitigation effort. Those approaches, however, cannot deliver the level of emissions reduction needed to stabilize the concentrations of GHGs in the atmosphere—especially in view of a growing global demand for energy and the associated increase in GHG emissions. Technological approaches that are effective in reducing atmospheric GHG concentrations and, at the same time, have little or no negative impacts on energy use and economic growth and prosperity are needed. Carbon capture and storage (CCS) promises to provide a significant reduction in GHG emissions.

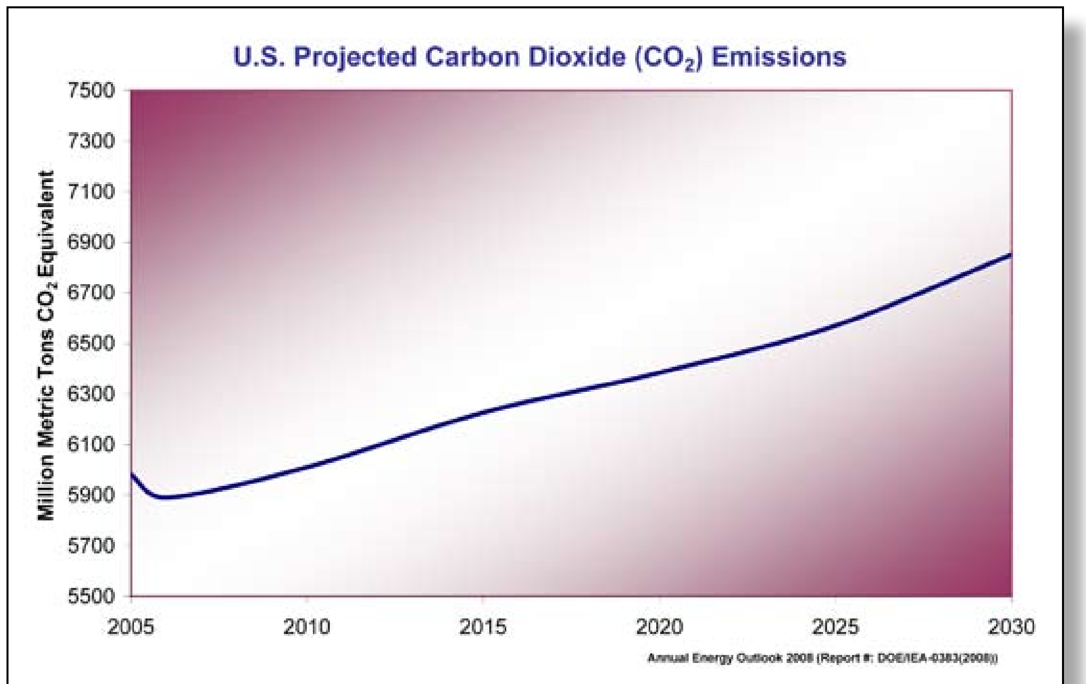
A Technology Approach to Reduce GHG Emissions

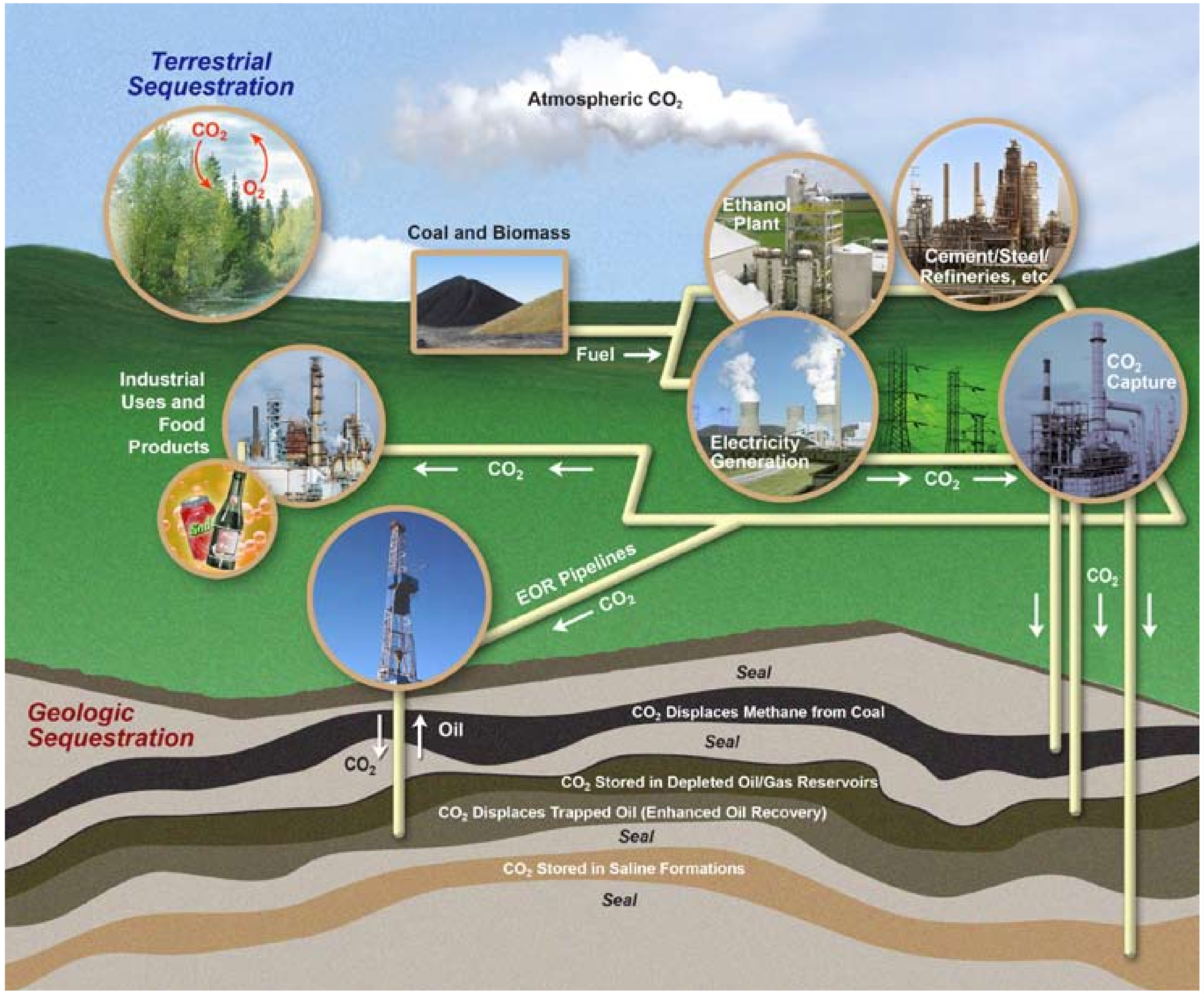
The U.S. Department of Energy's (DOE's) Office of Fossil Energy National Energy Technology Laboratory (NETL) is engaged in a research and development (R&D) Carbon Sequestration Program focusing on CCS technologies with significant potential for reducing GHG emissions and mitigating global climate change. The Program supports the UNFCC goal to reduce GHG emissions, as well as the National Energy Policy goals targeting the development of new technologies for reducing GHG emissions.

The graph "U.S. Electric Power Generation by Fuel Type," shown at top right, displays the *Annual Energy Outlook's* 2008 predictions of growth in energy generation by various fuel types. Coal is predicted to continue to dominate power generation for the next 25 years. Power generation from coal is one significant source of CO_2 emissions, making efforts to reduce these emissions a critical R&D goal.

The Energy Information Administration's graph titled "U.S. Projected Carbon Dioxide (CO_2) Emissions," shown at bottom right, illustrates the projected increase in CO_2 emissions over the next 25 years. Following AEO's 2008 assumptions, if no additional actions are taken, the U.S. will emit approximately 6,850 million metric tons (7,550 million tons) of CO_2 by 2030, increasing 2005 emission levels by more than 14 percent. The U.S. can work toward reducing GHG emissions with the development and implementation of appropriate CCS technologies.







What is Carbon Sequestration?

What is Carbon Sequestration?

Carbon sequestration encompasses the processes of capturing and storing CO_2 that would otherwise reside in the atmosphere for long periods of time. DOE is investigating a variety of carbon sequestration options. Geologic carbon sequestration involves the separation and capture of CO_2 at the point of emissions from stationary sources followed by storage in deep underground geologic formations. Terrestrial carbon sequestration involves the net removal of CO_2 from the atmosphere by plants during photosynthesis and its fixation in vegetative biomass and in soils.

It is expected that large numbers of new power plants and fuel processing facilities will be built in the coming decades, in both the developing world, as well as in some areas of the developed world, such as the U.S. and Canada. These new facilities, along with existing plants having the potential to be appropriately retrofitted, will create ample opportunities for deploying efficient and cost-effective CO_2 capture technologies. DOE's CO_2 capture efforts seek to cost-effectively capture and purify CO_2 using post-combustion, pre-combustion, or oxy-combustion technologies.

Geologic carbon sequestration is defined as the placement of CO_2 into a subsurface formation in such a way that it will remain permanently stored. DOE is investigating five types of underground formations for geologic carbon sequestration, each with different challenges and opportunities: (1) oil and natural gas reservoirs, (2) deep unmineable coal seams, (3) deep saline formations, (4) oil- and gas-rich organic shales, and (5) basalt formations.

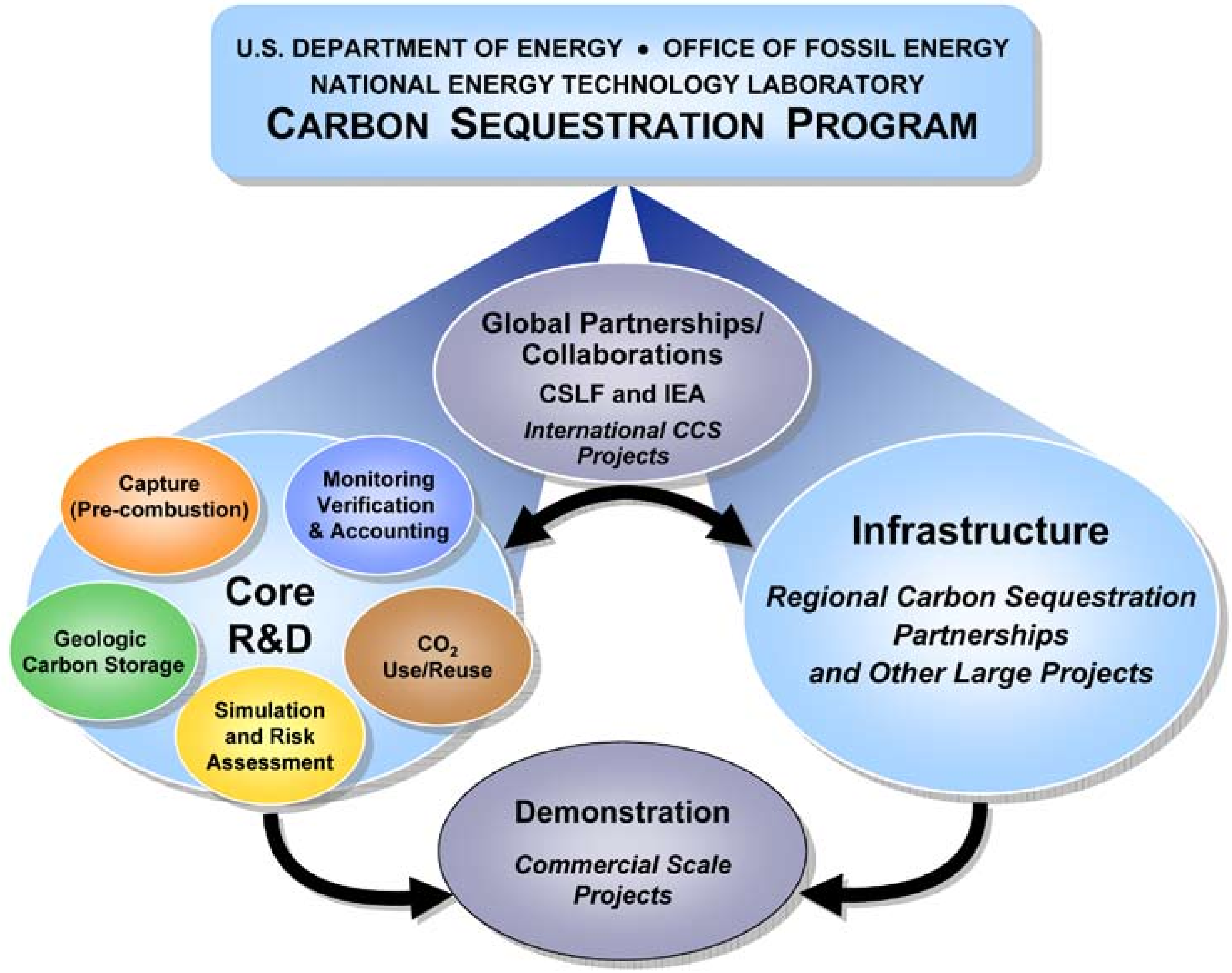
The process of carbon sequestration includes monitoring, verification, and accounting (MVA), as well as risk assessment, at the sequestration site. DOE's MVA efforts focus on development and deployment of technologies that can provide an accurate accounting of stored CO_2 and a high level of confidence that the CO_2 will remain permanently sequestered. Effective application of these MVA technologies will ensure the safety of sequestration projects with respect to the environment, and provide the basis for establishing carbon credit trading markets for sequestered CO_2. Risk assessment research focuses on identifying and quantifying potential risks to humans and the environment associated with carbon sequestration, and helping to ensure that these risks remain low.

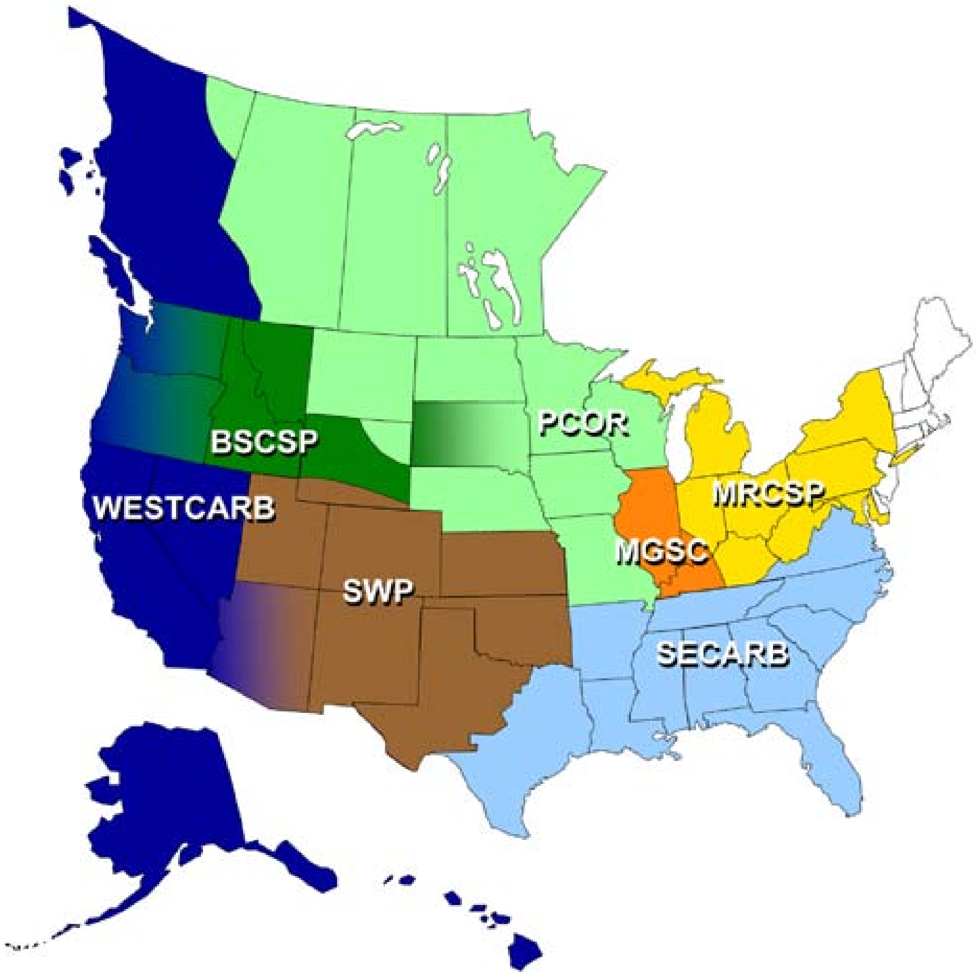
DOE's Carbon Sequestration Program

DOE's Carbon Sequestration Program involves two key elements for technology development and research: (1) Core R&D and (2) Infrastructure. The Core R&D element contains five focal areas for carbon sequestration technology development: (1) Pre-combustion Capture, (2) Geologic Carbon Storage, (3) Monitoring, Verification, and Accounting, (4) CO_2 Use/Reuse, and (5) Simulation and Risk Assessment. Core R&D is driven by technology needs and is accomplished through laboratory and pilot-scale research aimed at developing new technologies and new systems for GHG mitigation. The Infrastructure element includes large-scale projects and the Regional Carbon Sequestration Partnerships (RCSPs), a government/industry cooperative effort tasked with developing guidelines for the most suitable technologies, regulations, and infrastructure needs for CCS in different regions of the U.S. and Canada. The Core R&D and Infrastructure elements provide technology solutions which support the Global Partnerships/Collaborations and Demonstration elements.

DOE participates in international collaborations in the area of carbon sequestration, via the Carbon Sequestration Leadership Forum (CSLF). The CSLF is an international group that is focused on the development of improved, cost-effective technologies for the separation and capture of CO_2, transport of CO_2, and long-term safe storage of CO_2. The purpose of the CSLF is to make these technologies available internationally and to identify and address wider issues relating to carbon capture and storage, such as regulatory and policy options.

DOE's Carbon Sequestration Program is developing a portfolio of technologies with great potential to reduce GHG emissions. The Program's goal is to have a technology portfolio by 2012 for safe, cost-effective, and long-term carbon mitigation, management, and storage, which will lead to substantial market penetration after 2012. Reaching this goal requires an integrated R&D plan that will advance fundamental CCS technologies and prepare them for commercial-scale development. The Program works in concert with several programs within the Office of Fossil Energy that are developing and demonstrating technologies integral to coal-fueled power generation and coal conversion with potential for carbon capture, including Innovations for Existing Plants, Fuels, Clean Coal Power Initiative, Gasification, Fuel Cells, Turbines, and Advanced Research. Projects that meet the Program goal will result in large-scale units that come on-line around 2020. In the long-term, the Program is expected to contribute significantly to the reduction of GHG emissions.





Regional Carbon Sequestration Partnerships

Initiated by DOE's Office of Fossil Energy, the Regional Carbon Sequestration Partnerships (RCSPs) (see map at left) are a public/private cooperative effort tasked with developing guidelines for the most suitable technologies, regulations, and infrastructure needs for CCS in different regions of the U.S. and Canada. The energy sectors of both countries are very closely related. Geographical differences in fossil fuel use and CO_2 storage potential across the U.S. and Canada dictate regional approaches to sequestration of CO_2 and other GHGs. The seven RCSPs that form this network currently include more than 350 state agencies, universities, and private companies, spanning 42 states, and four Canadian provinces. In addition, agencies from six member countries of the CSLF are participating.

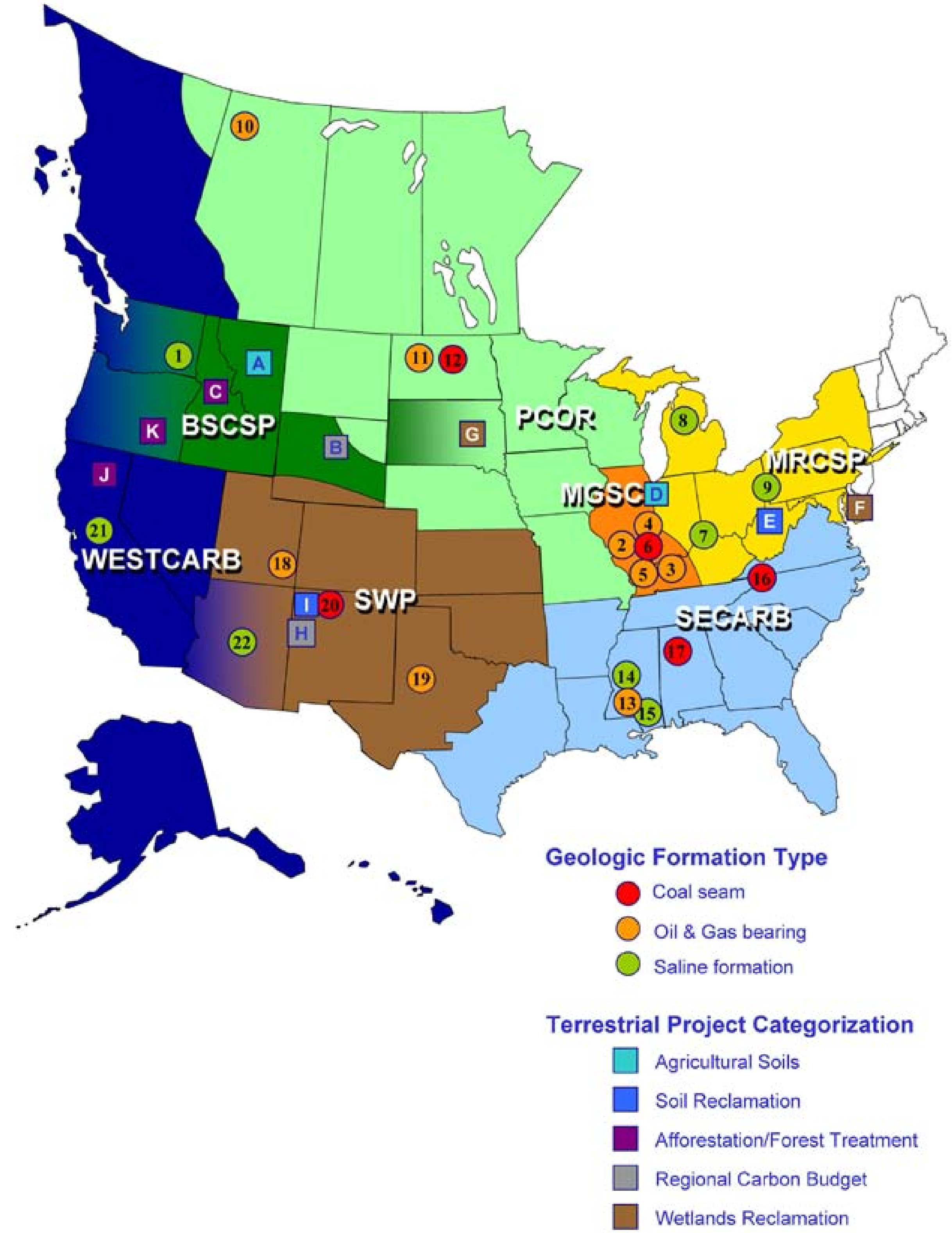
The RCSPs' effort consists of three distinct phases: (1) Characterization Phase (2003-2005); (2) Validation Phase (2005–2009); and (3) Development Phase (2008-2018). The Characterization Phase began in September 2003 with seven RCSPs working to develop the necessary framework to validate and potentially deploy CCS technologies. At the end of the Characterization Phase, the RCSPs had succeeded in establishing a national network of companies and professionals working to support CCS deployments, creating a National Carbon Sequestration Database and Geographic Information System (NATCARB), and raising awareness and support for CCS as a GHG mitigation option.

The Validation Phase focuses on validating the most promising regional opportunities to deploy CCS technologies by building upon the accomplishments of the Characterization Phase. Two different CO_2 storage approaches are being pursued in this phase: geologic and terrestrial carbon sequestration. Efforts are being conducted to (1) validate and refine current reservoir simulations for CO_2 storage projects; (2) collect physical data to confirm CO_2 storage potential and injectivity estimates; (3) demonstrate the effectiveness of MVA technologies; (4) develop guidelines for well completion, operations, and abandonment; and (5) develop strategies to optimize the CO_2 storage potential of various geologic formations.

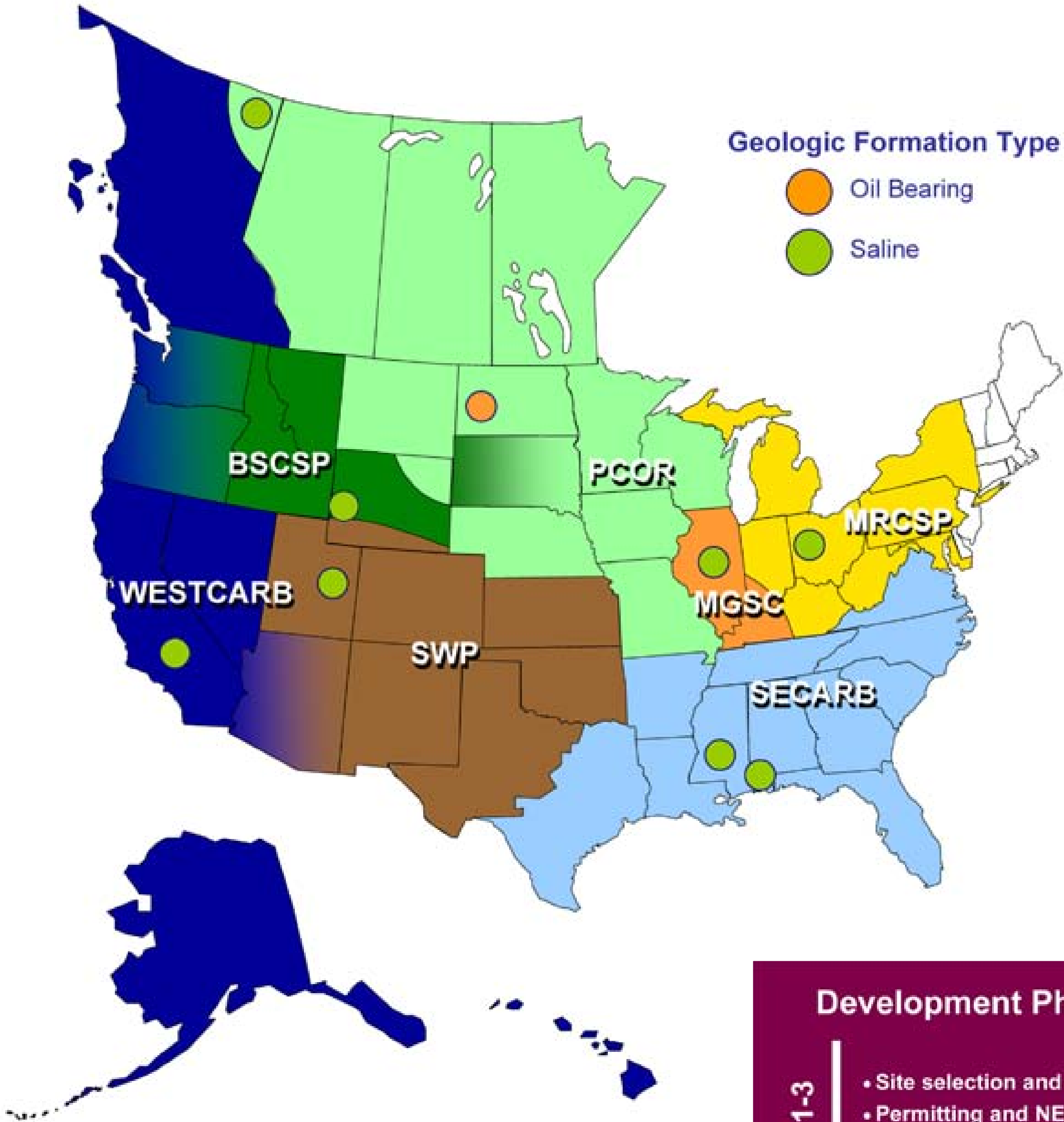
The Development Phase builds on the information generated in the Characterization and Validation Phases and involves the injection of 1 million tons or more of CO_2 by each RCSP into regionally significant geologic formations of different depositional environments. These large-volume injection tests are designed to demonstrate that CO_2 storage sites have the potential to store regional CO_2 emissions safely, permanently, and economically for hundreds of years. Results obtained from these efforts will provide the foundation for CCS technology commercialization throughout the United States.

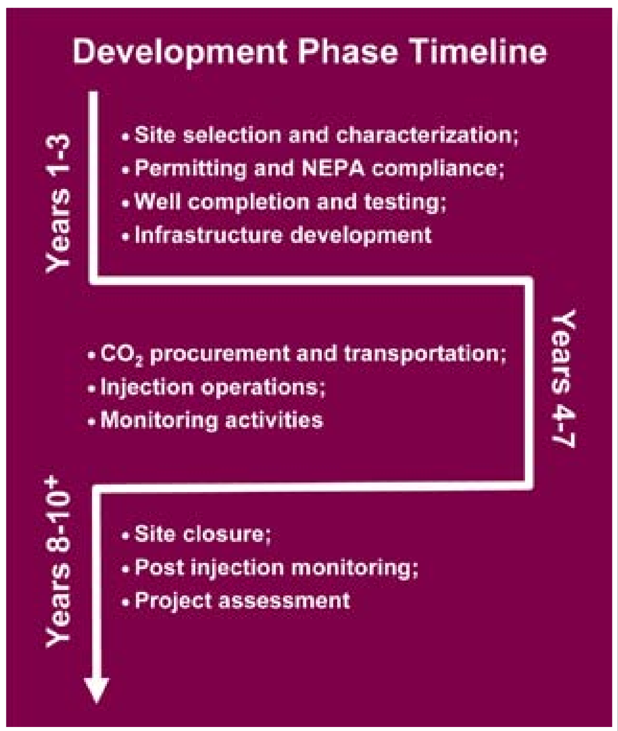
Regional Carbon Sequestration Partnership	Lead Organization	Member States/Provinces	Website
Big Sky Carbon Sequestration Partnership (BSCSP)	Montana State University	Montana, Idaho, South Dakota, Wyoming, Eastern Oregon and Washington, and adjacent areas in British Columbia and Alberta	http://www.bigskyco2.org/
Midwest Geological Sequestration Consortium (MGSC)	Illinois State Geological Survey	Illinois, Western Indiana, and Western Kentucky	http://www.sequestration.org/
Midwest Regional Carbon Sequestration Partnership (MRCSP)	Battelle Memorial Institute	Eastern Indiana, Eastern Kentucky, Maryland, Michigan, New York, Ohio, Pennsylvania, and West Virginia	http://www.mrcsp.org
Plains CO_2 Reduction (PCOR) Partnership	University of North Dakota, Energy and Environmental Research Center	Eastern Montana, Eastern Wyoming, Nebraska, Eastern South Dakota, North Dakota, Minnesota, Wisconsin, Iowa, Missouri, Alberta, Saskatchewan, Manitoba, and Northeastern British Columbia	http://www.undeerc.org/PCOR/
Southeast Regional Carbon Sequestration Partnership (SECARB)	Southern States Energy Board	East Texas, Arkansas, Louisiana, Mississippi, Alabama, Tennessee, Florida, Georgia, South Carolina, North Carolina, and Virginia	http://www.secarbon.org/
Southwest Regional Partnership (SWP)	New Mexico Institute of Mining and Technology	Western Texas, Oklahoma, Kansas, Colorado, Utah, and Eastern Arizona	http://www.southwestcarbonpartnership.org/
West Coast Regional Carbon Sequestration Partnership (WESTCARB)	California Energy Commission	Alaska, Western Arizona, Western British Columbia, California, Hawaii, Nevada, Western Oregon, and Western Washington	http://www.westcarb.org/

Regional Carbon Sequestration Partnerships—Validation Phase CO_2 Storage Projects



	Partnership	Geologic Province / Project Location	Geologic: Total CO_2 Injection (tons CO_2)	Geologic: Approximate Depth (feet)	Terrestrial: Estimated CO_2 Capacity
1	Big Sky Carbon Sequestration Partnership	Columbia Basin	3,000	2,500 – 4,000	
A		North Central MT			60 Mt over 20 years
B		Eastern WY			30 Mt over 10 years
C		Region-wide			640 - 1,040 Mt over 80 yrs
2	MGSC	Illinois Basin	50	1,550	
3		Illinois Basin	1,000	1,549	
4		Illinois Basin	3,000	1,548	
5		Illinois Basin	3,000	1,551	
6		Illinois Basin	200	1,000	
7	MRCSP	Cincinnati Arch	3,000	3,200 – 3,500	
8		Michigan Basin	10,000	3,200 – 3,500	
9		Appalachian Basin	3,000	5,900 – 8,300	
D		Region-wide			25 Mt over 20 years
E		Region-wide			100 Mt over 20 years
F		Cambridge, MD			TBD
10	The Plains CO2 Reduction Partnership PCOR	Keg River Formation	100,000	5,000	
11		Duperow Formation	<1,000	10,000 – 10,500	
12		Williston Basin	<1,000	1,600 – 1,800	
G		Great Plains wetlands complex (PPR)			14.4 Mt
13	SECARB	Gulf Coast } stacked test	500,000	10,304	
14		Gulf Coast		10,400	
15		Mississippi Coastal Plain	3,000	8,600	
16		Central Appalachian	1,000	1,600 – 2,300	
17		Black Warrior Basin	1,000	1,500 – 2,500	
18	SWP Southwest Partnership CO2 Sequestration	Paradox Basin, Aneth Field	450,000	5,600 – 5,800	
19		Permian Basin	900,000	5,800	
20		San Juan Basin	75,000	3,000	
H		Region-wide			TBD
I		San Juan Basin Coal Fairway (Navajo City, NM)			TBD
21	West Coast Regional Carbon Sequestration Partnership westcarb.org	Sacramento Basin	2,000	8,000	
22		Colorado Plateau	2,000	4,000	
J		Shasta County, CA			4,600 Mt over 80 years (CA)
K		Lake County, OR			900 Mt over 80 years (OR)





Regional Carbon Sequestration Partnerships—Development Phase

The Development Phase, which began in FY 2008 and is planned to continue through FY 2018, will demonstrate at large scale that CO_2 capture, transportation, injection, and storage can be achieved safely, permanently, and economically. The geologic structures to be tested during these RCSP large-volume sequestration tests (see map at left) may become candidate sites for future near zero emissions power plants. The primary goal of the Development Phase is to establish large-scale CCS projects across North America, where large volumes of CO_2 will be injected into a geologic storage formation containing significant sequestration potential in each Region. Each project will inject CO_2 over several years. Recognizing that CO_2 sources vary widely from region to region and that some regions will have limited access to large volumes of CO_2, injection volumes may vary. The RCSPs, however, are expected to maximize CO_2 injection volumes and fully utilize the infrastructure of their Region. Projects that procure CO_2 from post-combustion capture facilities and industrial vents will inject at least 1 million tons, while projects receiving CO_2 from natural gas processing plants or natural vents will inject over a million tons of CO_2, depending upon cost and availability. The Development Phase tests will be implemented in three stages, which will test key technologies during the project's life-cycle (see graphic at left).

While projects in the Validation Phase are designed to demonstrate that regional sequestration sites have the potential to store thousands of years' worth of CO_2 emissions in the U.S., the large-volume sequestration tests in the Development Phase will also address practical issues such as sustainable injectivity, well design for both integrity and increased capacity, and reservoir behavior with respect to prolonged CO_2 injection. Development Phase goals include: (1) collect physical data to confirm capacity and injectivity estimates made during the Characterization Phase; (2) validate the effectiveness of simulation models to predict and MVA technologies to measure CO_2 movement in the geologic formations, confirm the integrity of the seals, and confirm indirect storage in terrestrial ecosystems; (3) develop guidelines for well completion, operations, and closure in order to maximize storage potential and mitigate leakage; (4) develop strategies for optimizing storage capacity for various reservoir types; (5) develop public outreach strategies and communicate the benefits of CCS to various stakeholders; and (6) satisfy the regulatory and permitting requirements for CCS projects.

Regional Carbon Sequestration Partnerships—Development Tests*

Big Sky Carbon Sequestration Partnership—With the cooperation of industry partners, Cimarex and Schlumberger, the BSCSP plans to inject up to 2.7 million metric tons (3 million tons) of CO_2 from a Cimarex Energy gas processing plant into the Nugget Sandstone on the Riley Ridge Unit on the LaBarge Platform in southwest Wyoming. The Nugget sandstone represents a key opportunity for sequestration in the region because it can potentially store more than 100 years of current emissions from power plants in Wyoming and is similar to other sequestration target saline aquifers in the region.

Midwest Geological Sequestration Consortium—MGSC is partnering with the Archer Daniels Midland (ADM) Company to conduct a deep > 1,500 m (> 5,000 ft) large-scale test into the ~460 m (~1,500 ft) thick Mt. Simon Sandstone in the Illinois Basin. One million metric tons of CO_2 (1.1 million tons) from ADM's ethanol production facility will be injected over three years at ADM's plant site. The lower porous Mt. Simon is understood to have been deposited in a braided stream and alluvial fan system within a pull-apart basin. The injection will test the effects of heterogeneity of the formation on capacity and containment.

Midwest Regional Carbon Sequestration Partnership—In the Development Phase, MRCSP will validate large-volume CO_2 storage in a relatively shallow 900 m (3,000 ft) and thin 90 m (300 ft) portion of the Mt. Simon sandstone formation by injecting one million tons of CO_2 over four years from an ethanol production facility. The Andersons Marathon Ethanol LLC (TAME) Plant will be the injection site for MRCSP's test and the source of CO_2 for this test.

Plains CO_2 Reduction Partnership—During the Development Phase, the PCOR Partnership's large-volume injection test in Canada's Alberta Basin will validate the co-sequestration of CO_2 and hydrogen sulfide from a large gas processing plant into a deep saline formation. In addition, PCOR Partnership will transport approximately one million metric tons of CO_2 per year for five years from the Antelope Valley Station, a coal-fired power plant in central North Dakota. The CO_2 will be injected into an oil reservoir located in western North Dakota. This large-scale test will validate both EOR and CO_2 storage in a deep carbonate formation that is also a saline formation.

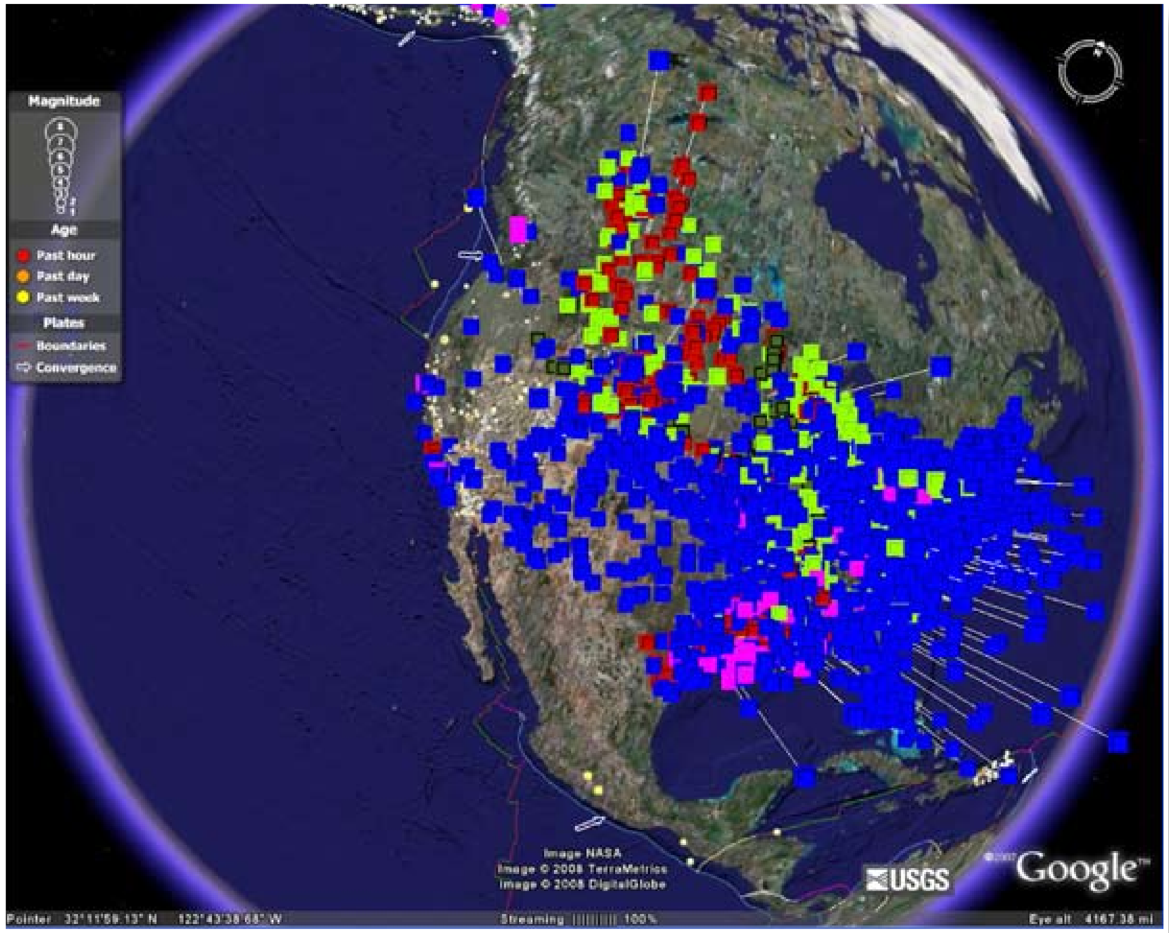
Southeast Regional Carbon Sequestration Partnership—The SECARB will conduct CO_2 injection tests at two locations. The Early Test will inject 1.4 million metric tons (1.5 million tons) of CO_2 from a natural source into the lower Tuscaloosa Formation Massive Sand Unit. The Anthropogenic Test will inject one million tons of CO_2 over a four-year period using CO_2 captured from a coal-fired power plant in the region. Extensive site characterization through drilling and geophysical logging has been performed at the Mississippi saline formation test site.

Southwest Regional Partnership for Carbon Sequestration—The SWP's large-scale test involves the injection of three million tons of CO_2 per year over a four-year period into the deep, Permian-aged White Rim sandstone in the Farnham Dome of Utah. The CO_2 will come from a natural CO_2 source in the Nugget Sandstone.

West Coast Regional Carbon Sequestration Partnership—The WESTCARB will perform an integrated CO_2 capture and storage test at the Kimberlina Test Facility in Kern County, California. The Partnership will inject one million tons of CO_2 over four years into a deep 2,000+ meter (7,000+ feet) geologic formation below a 50-MW, zero-emission power plant. The site is located at the southern end of the Great Central Valley, one of the largest CO_2 storage resources in WESTCARB's seven-state territory.

RCSP	Title	Geologic Formation	Depth (ft)	Source of CO_2	Volume to Inject (in metric tons CO_2/year)	Total Amount of CO_2 Injected (metric tons)
BSCSP	Large Volume Injection to Assess Commercial Scale Geological Sequestration in Saline Formations	Nugget Sandstone	11,000	Helium and Natural Gas Processing Plant	1,000,000	2,700,000
MGSC	Illinois Basin – Decatur Project	Mt. Simon Sandstone in the Illinois Basin	5,000–7,000	Ethanol Plant	365,000	1,000,000
MRCSP	Large Volume injection of CO_2 in Western Ohio	Mt. Simon Sandstone in the Cincinnati Arch	3,000–3,600	Ethanol Plant	250,000	1,000,000
PCOR	Williston Basin CO_2 Sequestration and EOR	Deep depleted oil fields in the Williston Basin, carbonate rocks	12,000	Post Combustion Capture Facility	1,000,000	5,000,000
	Fort Nelson CO_2 acid gas injection project	Sandstone in the Alberta Basin	5,000	Natural Gas Processing Plant	1,000,000	5,000,000
SECARB	SECARB Development Phase Saline Formation Demonstration - Cranfield	Sandstones of the lower Tuscaloosa Formation	10,500	Natural Source	1,000,000 for Early Test	1,500,000
	SECARB Development Phase Saline Formation Demonstration - Anthroprogenic	Tuscaloosa Formation Massive Sand Unit	9,500	Post Combustion Capture Facility	100,000 to 250,000	At least 400,000
SWP	Farnham Dome Deep Saline Deployment Project	Deep triassic, jurrassic, and permian aged sandstones in the Farnham Dome	5,000+	Natural Source	1,000,000	2,900,000
WESTCARB	Sequestration of CO_2 from OxyFuel Combustion Unit, Kern County, CA	A San Joaquin Basin sandstone formation	7000+	Oxycombustion Power Plant	250,000	1,000,000

* Information current as of 2008.



In 2009, NATCARB will provide CCS data, not only through high-end GIS and database query tools, but through simplified display for the general public employing readily available web tools such as Google Earth™ and Google Maps™. Images show locations of CO_2 emission sources, inventoried and accessible through the NATCARB portal, and displayed with Google Earth™. At the same time, images of geologic features and earthquakes from the U.S. Geological Survey are displayed. The experimental Google Earth™ NATCARB viewer is accessible through http://geoportal.kgs.ku.edu/NATCARB/basic_view/sources.cfm.

View of the experimental NATCARB Google Earth™ viewer.

National Carbon Sequestration Database and Geographical Information System

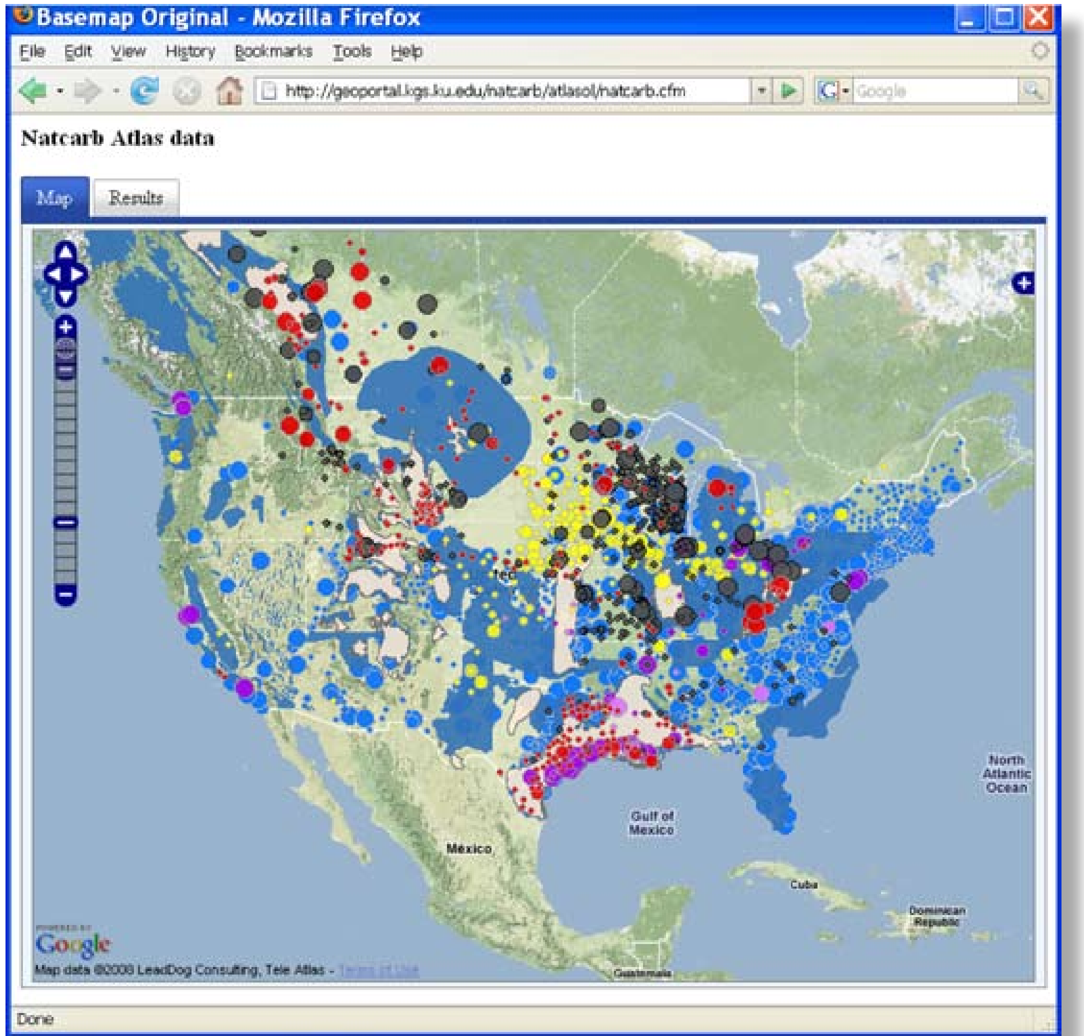
A National Look at Carbon Sequestration

The DOE's RCSPs generated the data for the maps displayed in this new version of the *Carbon Sequestration Atlas of the United States and Canada*. Key geospatial data (CO_2 emission sources, potential CO_2 storage sites, CO_2 transportation, land use, etc.) assembled through the National Carbon Sequestration Database and Geographical Information System (NATCARB) can assist in planning for efficient implementation of CCS on a national scale. NATCARB is a geographic information system (GIS) that integrates carbon sequestration data from the RCSPs and various other sources. The purpose of NATCARB is to provide a national view of the CCS potential in the U.S. and Canada. The digital spatial database allows users to estimate the amount of CO_2 emitted by sources (such as power plants, refineries, and other fossil-fuel-consuming industries) in relation to geologic formations that can provide safe CO_2 storage over long periods of time. NATCARB provides all stakeholders with improved online tools for the display and analysis of CO_2 capture and storage data.

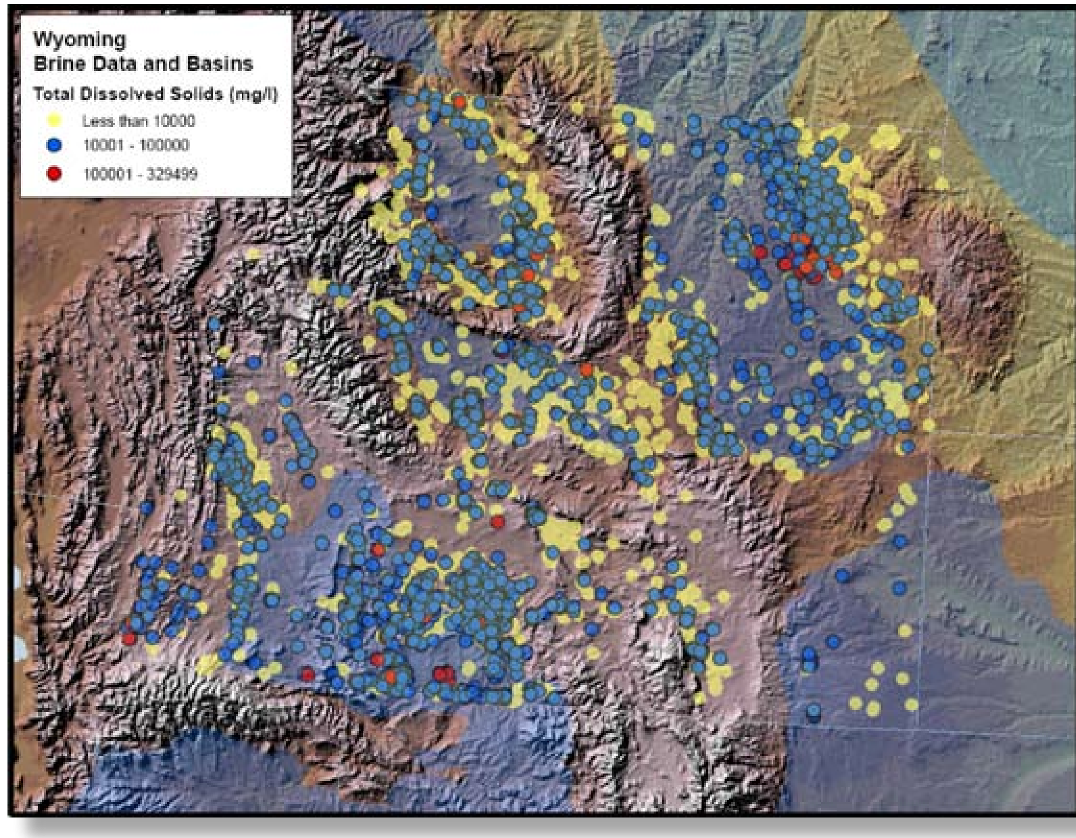
NATCARB organizes and enhances the critical information about CO_2 stationary emission sources and develops the technology needed to access, query, model, analyze, display, and distribute national CO_2 storage resource data for carbon management. Data are generated, maintained, and enhanced locally at the RCSP level, or at specialized data warehouses and public servers (e.g., U.S. Geological Survey-EROS Data Center, U.S. Environmental Protection Agency (EPA), and the Geography Network), and assembled, accessed, and analyzed in real-time through a single geoportal.

NATCARB is a functional demonstration of distributed data-management systems that cross the boundaries between institutions and geographic areas. It forms the first step toward a functioning carbon sequestration information cyber-infrastructure. NATCARB online access has been modified to address the broad needs of a spectrum of users, and includes not only GIS and database query tools for the high-end technical user, but also simplified displays for the general public employing readily available web tools such as Google Earth™ and Google Maps™.

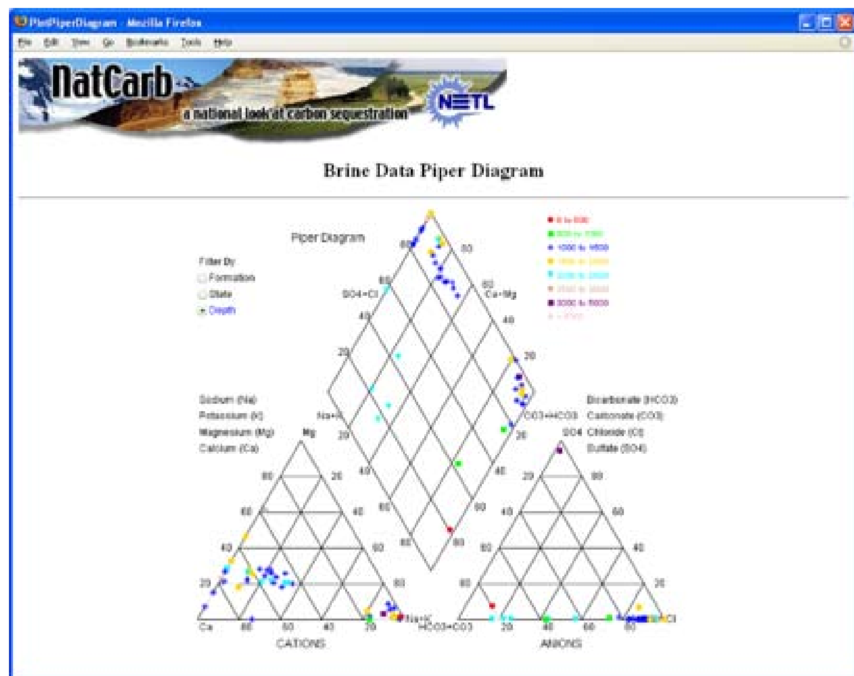
All map layers and data tables used to construct the national estimates of CO_2 stationary sources and geologic storage resources are available through interactive display and download through the NATCARB website http://www.NATCARB.org.



Example image of data accessible and displayed through NATCARB using Google Map™. This approach provides user-friendly access to national and regional information on CO_2 emission by sources (such as power plants, refineries, and other fossil-fuel-consuming industries) in relation to geologic formations that can provide safe CO_2 storage over long periods of time. Data can be queried to provide access to tabular data (see figure at right).



Regional data on potential CO_2 geologic storage sites can be assembled and displayed through NATCARB. The image above shows the distribution of locations in Wyoming with over 15,000 water samples from brine formations. Data are categorized by total dissolved solids (TDS). Samples with less than 10,000 mg/l TDS are considered potentially potable water and need to be protected (yellow dots). Formations containing TDS concentrations above 10,000 mg/l are sites that merit further evaluation for potential CO_2 storage (blue and red dots). Basins containing brine formations that have been evaluated are highlighted in blue. Data on brine geochemistry can be accessed and summarized with several additional online tools (see figure below). All data were assembled through NATCARB.



Methodologies Used to Estimate CO_2 Stationary Source Emissions and CO_2 Geologic Storage Potential

CO_2 Stationary Source Emissions Summary

Introduction

The Capture Working Group of DOE's Regional Carbon Sequestration Partnerships (RCSPs) summarized the calculations, emissions factors, and databases employed by the RCSPs with respect to CO_2 stationary source emissions estimation methods (Appendix A: CO_2 Stationary Source Emission Estimation Methodologies Summary). Carbon dioxide stationary sources include power plants, ethanol plants, petroleum and natural gas processing facilities, cement and lime plants, and the following facilities: agricultural processing, industrial, iron and steel production, and fertilizer-producing. Estimation methods include the use of databases and emissions factors which are listed by CO_2 source type in Appendix A.

The documents used to identify each CO_2 stationary source, as well as the practical quantitative method (e.g., emission factors, continuous emissions-monitoring results, emission estimate equations) used to estimate CO_2 emissions from a particular source, are listed in the "CO_2 Emissions Methodology References" section of Appendix A. The data sources used to determine specific plant capacities, production outputs, or fuel usage data are listed by RCSP in the "Data References by Partnership and Industry" section of Appendix A.

Approach

The approach for determining these methodologies was to first identify significant CO_2 emission sources within each Region, and then to assess the availability of CO_2 emission data or to apply an estimate of the CO_2 emissions based upon sound scientific and engineering principles. In each RCSP, the emissions were grouped by emission source, and a methodology was established for each emission source category; the methodology was then utilized to estimate the CO_2 emissions from each emission source category. To summarize these efforts, nine tables containing CO_2 emission estimation methodology and equations for the major CO_2 stationary source industries have been created. Each RCSP was responsible for developing GHG emission inventories and stationary source surveys within their respective Region. Approximately 4,800 stationary sources have been documented for the seven RCSPs.

CO_2 Estimation Methodology

For any stationary source within a given industry type, the RCSPs employed CO_2 emissions estimate methodologies that are based on the most readily available representative data for that particular industry type within the respective Region. CO_2 emissions data provided by databases (such as Emissions & Generation Resource Integrated Database [eGRID], ECOFYS, and others) were the first choice for all of the RCSPs, both for identifying major CO_2 stationary sources and for providing reliable emission estimates. These databases are considered to contain reliable and accurate data obtained from direct emissions measurements via continuous emissions monitoring systems. One drawback of formal databases can be the delay between data collection and data publication, but this does not present a significant problem for the RCSPs as the dates of information are clear. When databases were not available, stationary source facility production or fuel usage were coupled with CO_2 emissions factors to estimate annual CO_2 emissions from the production or fuel usage data. Emissions factors, fuel usage data, and facility production data were obtained from various databases, websites, and publications. Stationary source spatial location data (latitude and longitude) were determined from a variety of sources. Some databases (eGRID) contain latitude and longitude information for each stationary source. Where spatial location information was not available through an emissions database, other spatial location methods were utilized. These include the use of mapping tools (Google Earth, TerraServer, and U.S. Geological Survey's Digital Orthophoto Imagery) equipped with geospatially defined data, along with web-based databases (Travelpost) containing latitude and longitude information for various U.S. locations.

Methodology for Development of Geologic Storage Estimates for Carbon Dioxide

Introduction

The "Methodology for Development of Geologic Storage Estimates for Carbon Dioxide" (Appendix B) is an update to the 2006 "Methodology for Development of Carbon Sequestration Capacity Estimates" published in the *2007 Carbon Sequestration Atlas of the United States and Canada (Atlas I)*. The Capacity and Fairways Subgroup, convened by the Geologic Working Group for the RCSPs, lead this effort to describe the methodologies used to produce the geologic storage resource estimates for CO_2 in the *2008 Carbon Sequestration Atlas of the United States and Canada (Atlas II)*. The peer-reviewed methodologies represent simplified assumptions used to estimate the amount of CO_2 that can be stored in subsurface geologic environments of the United States and parts of Canada.

The Capacity and Fairways Subgroup includes representatives from DOE, each RCSP, NATCARB, the CSLF, and multiple State Geological Surveys.

The RCSPs are charged with providing a quantitative estimate of the geologic storage resource for CO_2 in the subsurface environments of their regions. These estimates are necessary to indicate the extent to which CCS technologies could contribute to the reduction of CO_2 emissions into the atmosphere. This assessment is a high-level overview and is not intended as a substitute for site-specific assessment and testing. The methodologies described were designed to integrate results of data compiled by the seven RCSPs for three types of geologic formations: saline formations, unmineable coal seams, and oil and gas reservoirs. These methodologies are developed to be consistent across North America for a wide range of available data. Results of this assessment are intended to be distributed by a GIS and are available as hard-copy results in *Atlas II*.

Atlas II provides CO_2 ***storage resource*** estimates by state/province and RCSP. Methodologies presented describe calculations and assumptions used for CO_2 **storage resource** estimates. A CO_2 ***storage 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 **storage resource** assessments do not include economic or regulatory constraints; only physical constraints to define the accessible part of the subsurface are applied. Economic or regulatory constraints are included in CO_2 ***capacity*** estimates. It should also be noted that for the development of specific commercial-scale geologic storage sites, economic and regulatory constraints must be considered to determine the portion of the CO_2 storage resource that is available under various development scenarios. Under the most favorable economic and regulatory scenarios, 100 percent of the estimated CO_2 **storage resource** may be considered CO_2 **capacity**.

Methods for estimating subsurface volumes are widely and routinely applied in petroleum, groundwater, underground natural gas storage, and Underground Injection Control disposal-related estimations. Therefore, the volumetric method is the basis for CO_2 storage resource calculations in *Atlas II*. The volumetric formula uses porosity, area, and thickness in a Monte Carlo simulation approach with various efficiency terms included to account for ranges of variations in the geologic volumetric properties and the fraction of the accessible pore volume that is most likely to be contacted by injected CO_2.

Types of Geologic Environments

For the purposes of this assessment, the subsurface is categorized into five major geologic formations: saline formations, coal seams, oil and gas reservoirs, shale, and basalt formations. Each of these is defined and input parameters for CO_2 storage resource calculations are described in Appendix B. Carbon dioxide storage resource has been quantified where possible for saline, coal, oil, and gas, whereas shale and basalt formations are presented as future opportunities and not assessed in this document.

SALINE FORMATION CO_2 STORAGE RESOURCE ESTIMATING

Saline formations are composed of porous rock saturated with brine and capped by one or more regionally extensive impermeable rock formations enabling trapping of injected CO_2. A saline formation assessed for storage is defined as a porous and permeable body of rock containing water with total dissolved solids (TDS) greater than 10,000 parts per million (ppm), which can store large volumes of CO_2. A saline formation can include more than one named geologic formation or be defined as only part of a formation. Saline formations have the largest CO_2 storage resource potential and are widespread throughout the United States and Canada.

OIL AND GAS RESERVOIR CO_2 STORAGE RESOURCE ESTIMATING

Typical mature oil and gas reservoirs in North America have held crude oil and natural gas over millions of years. They consist of a layer of permeable rock with a layer of nonpermeable rock (caprock) above, such that the nonpermeable layer forms a trap that holds the oil and gas in place. Oil and gas fields have many characteristics that make them excellent target locations for geologic storage of CO_2. The geologic conditions that trap oil and gas are also the conditions that are conducive to long-term CO_2 storage.

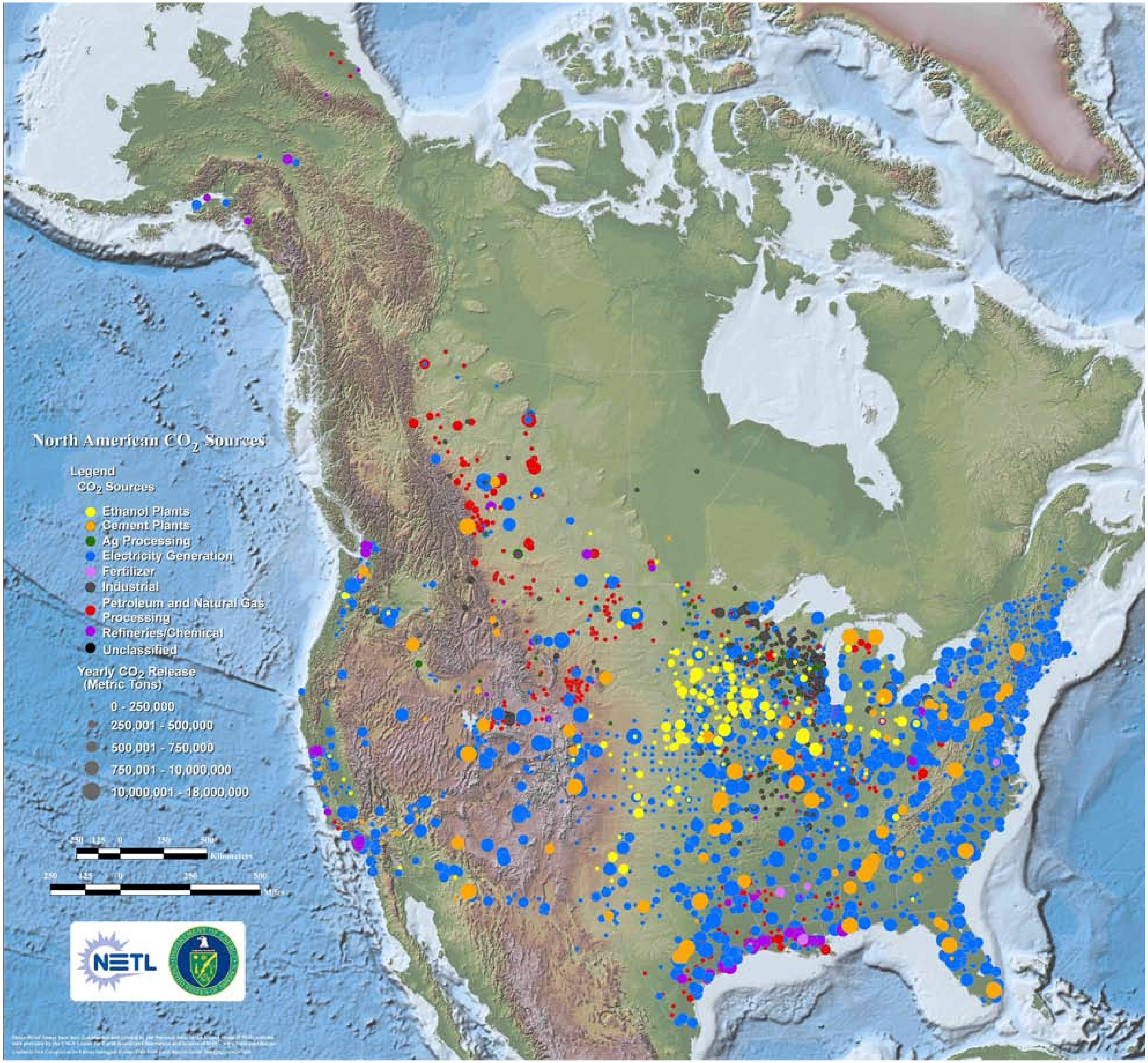
As a value-added benefit, CO_2 injected into a mature oil reservoir can enable incremental oil to be recovered. A small amount of CO_2 will dissolve in the oil, increasing its bulk volume and decreasing its viscosity, thereby facilitating flow to the wellbore. Typically, primary oil recovery and secondary recovery via a water flood produce 30-40 percent of a reservoir's original oil-in-place (OOIP). Enhanced Oil Recovery (EOR) via a CO_2 flood allows recovery of an additional 10-15 percent of the OOIP.

COAL SEAM CO_2 STORAGE RESOURCE ESTIMATING

Carbon dioxide storage opportunities exist within coal seams. All coals have varying amounts of methane adsorbed onto pore surfaces, and wells can be drilled into unmineable coalbeds to recover this coalbed methane (CBM). Initial CBM recovery methods, such as dewatering and depressurization, leave a considerable amount of methane in the formation. Additional recovery can be achieved by sweeping the coalbed with CO_2. Depending on coal rank, as few as 3 to as many as 13 molecules of CO_2 may be adsorbed for each molecule of methane released, thereby providing an excellent storage site for CO_2 along with the additional benefit of enhanced coalbed methane (ECBM) recovery.

Results

A summary of the National CO_2 storage resource estimates computed by each RCSP and compiled by NATCARB appears in the "National Perspectives" section of *Atlas II*. Regional details of these CO_2 storage resource estimates appear in the "Regional Carbon Sequestration Partnerships Perspectives" section of *Atlas II*. Lastly, a State summary of CO_2 storage resource estimates appears in Appendix C of *Atlas II*.



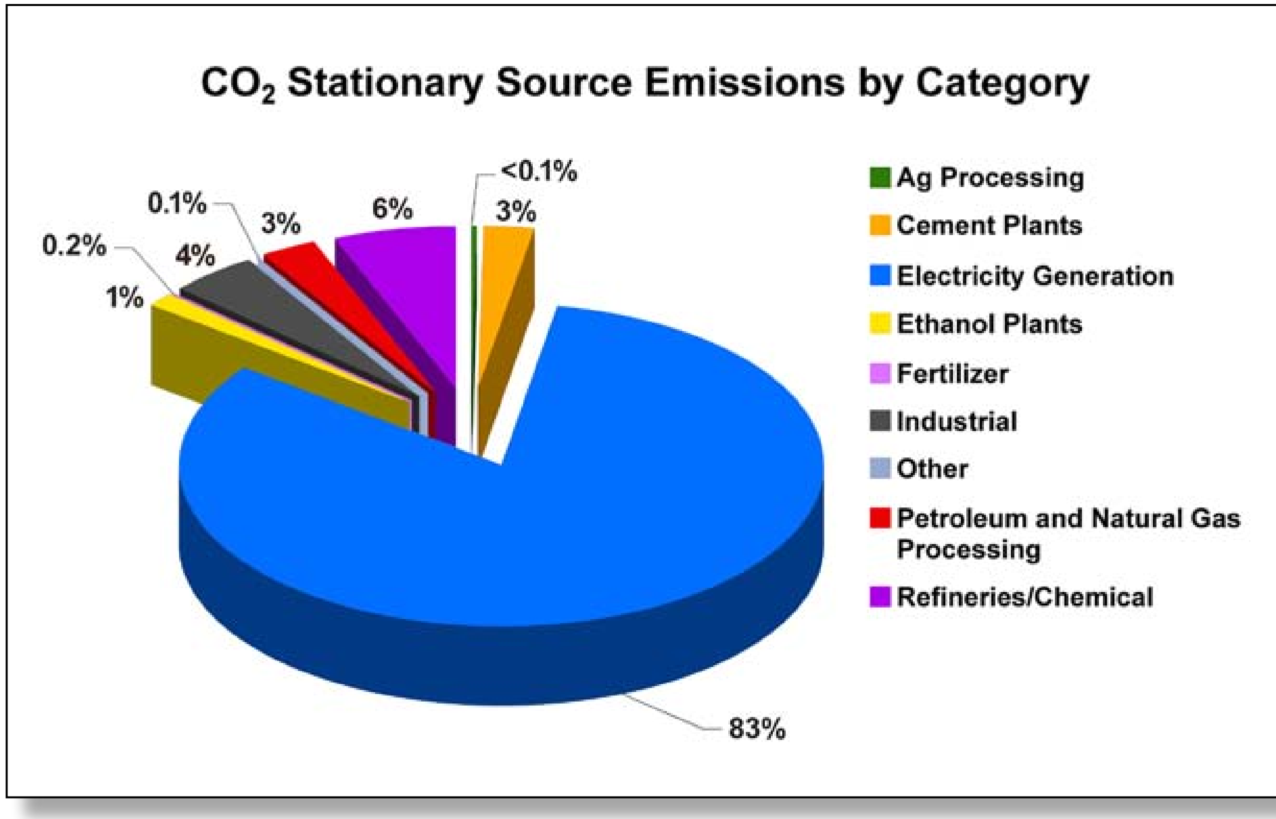
This map displays stationary source data which were obtained from the RCSPs and other external sources and compiled by NATCARB. Each colored dot represents a different type of stationary source with the dot size representing the relative magnitude of the CO_2 emission source (see map legend).

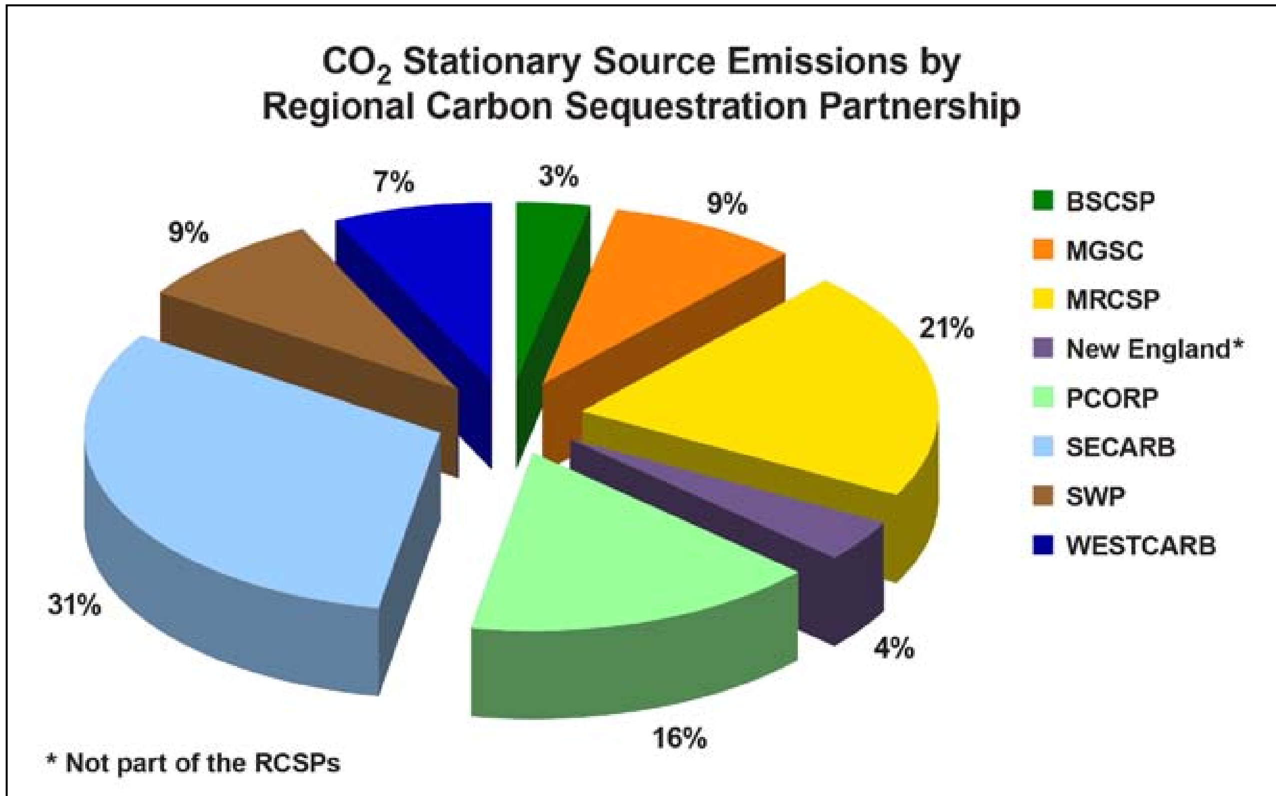
Carbon Dioxide Sources

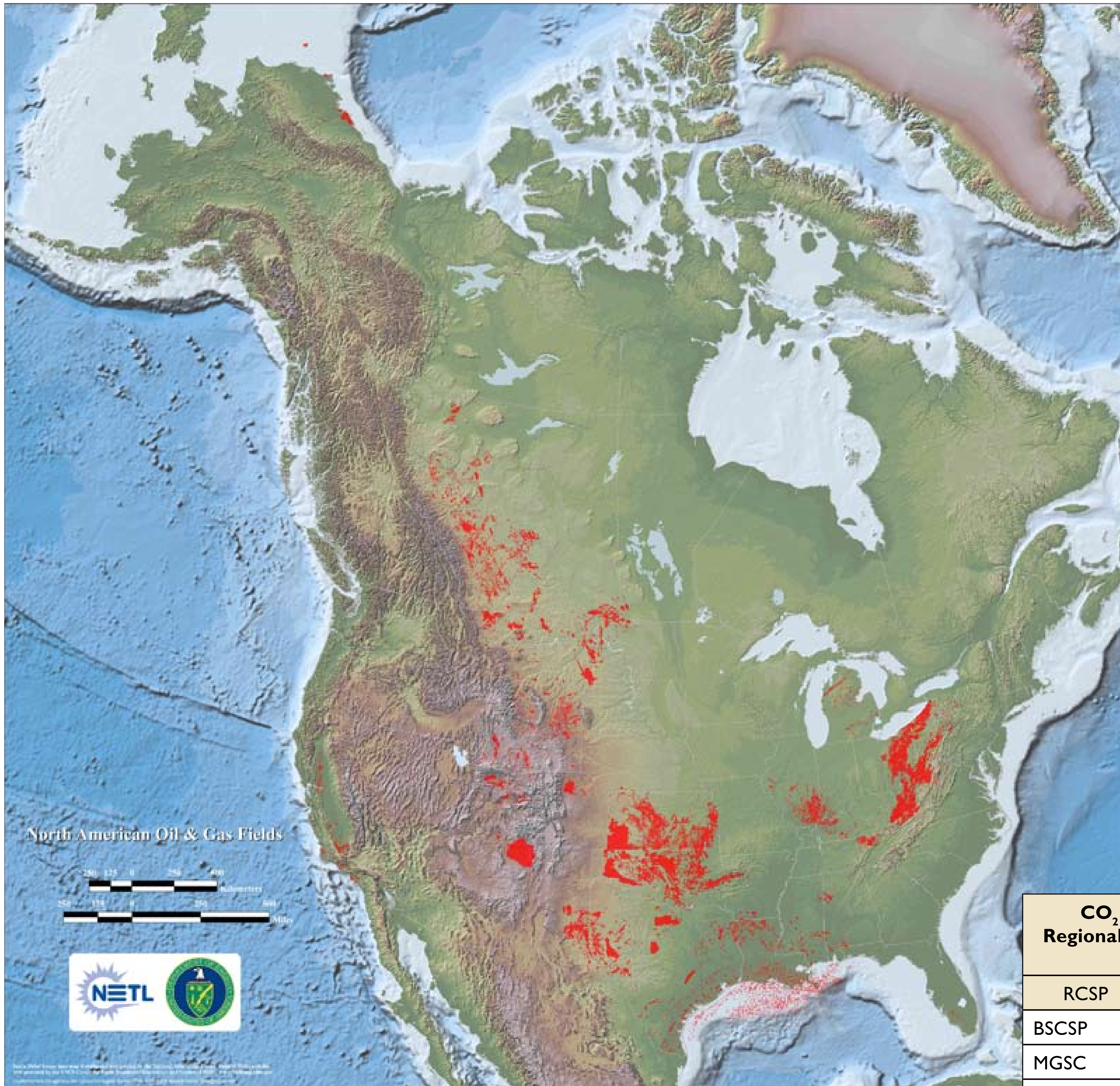
There are two types of CO_2 emission sources: stationary sources and non-stationary sources. Non-stationary source emissions include CO_2 emissions from the transportation sector (vehicles, railroads, airplanes, etc.). Stationary source emissions come from a particular, identifiable, localized source, such as a power plant. Carbon dioxide from stationary sources can be separated from plant emissions and subsequently transported to a geologic storage injection site. The "North American CO_2 Sources" map displays the location and relative magnitude of a variety of CO_2 stationary sources.

According to the EPA in 2006, total U.S. GHG emissions were estimated at 7,100 million metric tons (7,800 million tons) CO_2 equivalent. This estimate included CO_2 emissions as well as other GHGs such as methane (CH_4), nitrous oxide (N_2O), and hydrofluorocarbons (HFCs). Annual GHG emissions from fossil fuel combustion, primarily CO_2, were estimated at 5,600 million metric tons (6,200 million tons) with 3,800 million metric tons (4,200 million tons) from stationary sources.

The "CO_2 Stationary Source Emissions by Category" pie chart (top right) contains values, gathered by the RCSPs and compiled by NATCARB (illustrated on the "North American CO_2 Sources" map), showing that CO_2 stationary source emissions result largely from electric power generation, energy use, and industrial processes. While not all potential GHG sources have been examined, NETL's RCSPs have documented the location of more than 4,600 stationary sources with total annual emissions of over 3,200 million metric tons (3,600 million tons) of CO_2. The "CO_2 Stationary Source Emission by Regional Carbon Sequestration Partnership" pie chart (bottom right) displays the amount of CO_2 stationary source emissions identified by each RCSP. For details on sources by state, see Appendix C.







This map displays oil and gas reservoir data which were obtained by the RCSPs and other sources and compiled by NATCARB.

Oil and Gas Reservoirs

Mature oil and gas reservoirs have held crude oil and natural gas for millions of years. The reservoirs consist of a layer of permeable rock with a layer of nonpermeable rock (caprock) above, such that the nonpermeable rock layer forms a trap that holds the oil and gas in place. Oil and gas reservoirs have many characteristics that make them excellent target locations for geologic storage of CO_2. The geologic conditions that trap oil and gas are also the conditions that are conducive to CO_2 sequestration.

As a value-added benefit, when CO_2 is injected into a mature oil reservoir, it can produce additional oil. This process, enhanced oil recovery (EOR), begins by injecting CO_2 into an oil reservoir. A small amount of the injected CO_2 dissolves in the oil, increasing the bulk volume and decreasing the viscosity, thereby facilitating flow to the wellbore. Carbon dioxide injection allows recovery of an additional 10–15 percent of the oil. NETL's work in this area is focused on increasing the amount of CO_2 that remains in the ground as part of CO_2 EOR injection.

While not all potential mature oil and gas reservoirs in all states and provinces have been examined, the RCSPs have documented the location of 138 billion metric tons (152 billion tons) of geologic CO_2 storage potential in more than 10,000 oil and gas reservoirs distributed over 27 states and 3 provinces. This is an increase of approximately 56 billion metric tons (62 billion tons) of identified CO_2 storage potential from the previous version of the *Atlas.* For details on oil and gas storage by state, see Appendix C.

CO_2 Storage Resource Estimates by Regional Carbon Sequestration Partnership for Oil and Gas Reservoirs

RCSP	Billion Metric Tons	Billion Tons
BSCSP	1.5	1.6
MGSC	0.4	0.4
MRCSP	8.4	9.3
PCOR	24.1	26.5
SECARB	31.1	34.3
SWP	65.0	71.7
WESTCARB	7.7	8.5
TOTAL	138	152

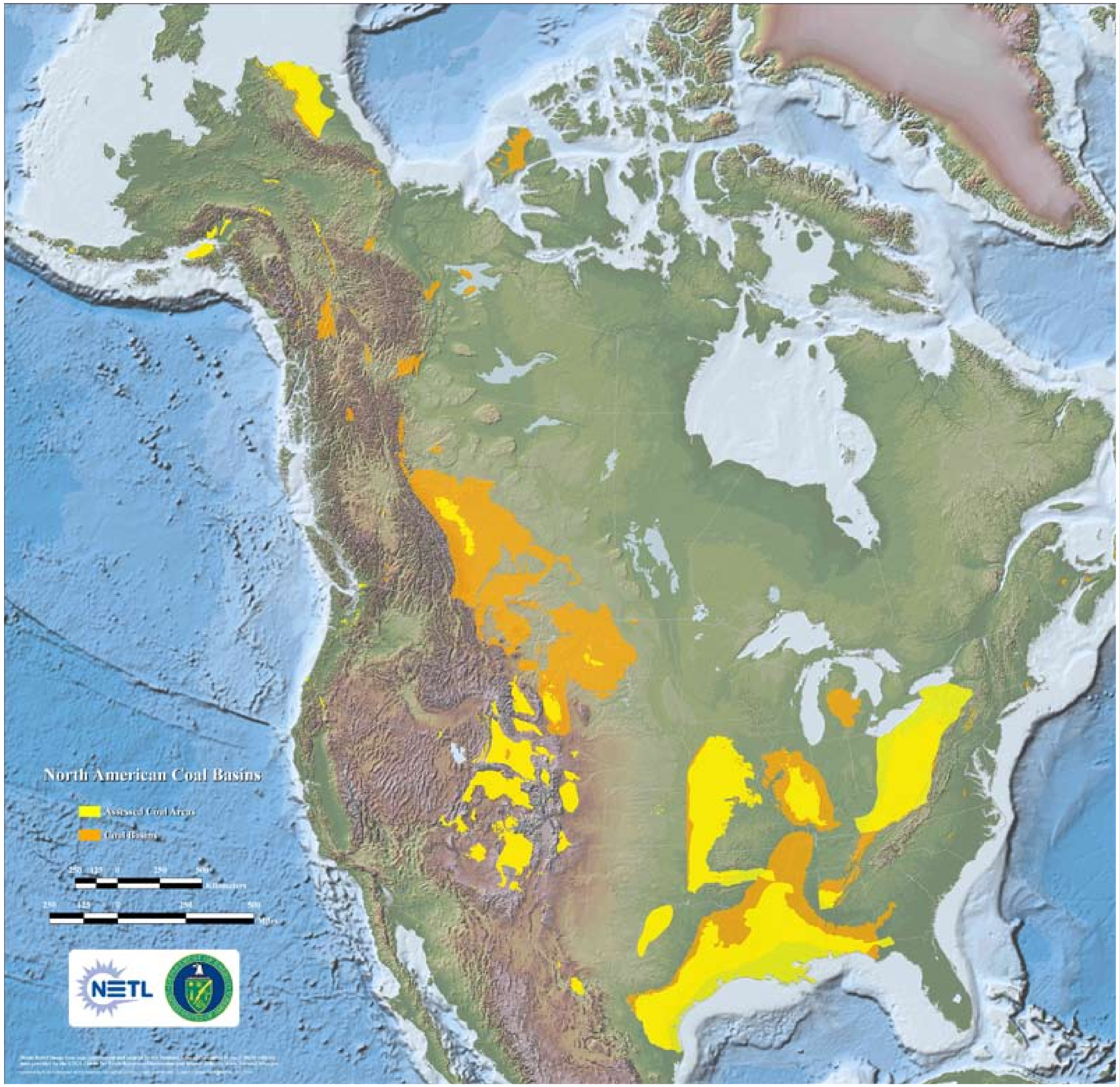
Unmineable Coal Seams

Unmineable coal seams are too deep or too thin to be economically mined. All coals have varying amounts of methane adsorbed onto pore surfaces, and wells can be drilled into unmineable coalbeds to recover this coalbed methane (CBM). Initial CBM recovery methods, such as dewatering and depressurization, leave a considerable amount of methane in the formation. Additional recovery can be achieved by sweeping the coalbed with CO_2. Depending on the type of coal, a variable amount of methane is released, thereby providing an excellent storage site for CO_2 along with the additional benefit of enhanced coalbed methane (ECBM) recovery. Similar to maturing oil reservoirs, unmineable coalbeds are good candidates for CO_2 storage.

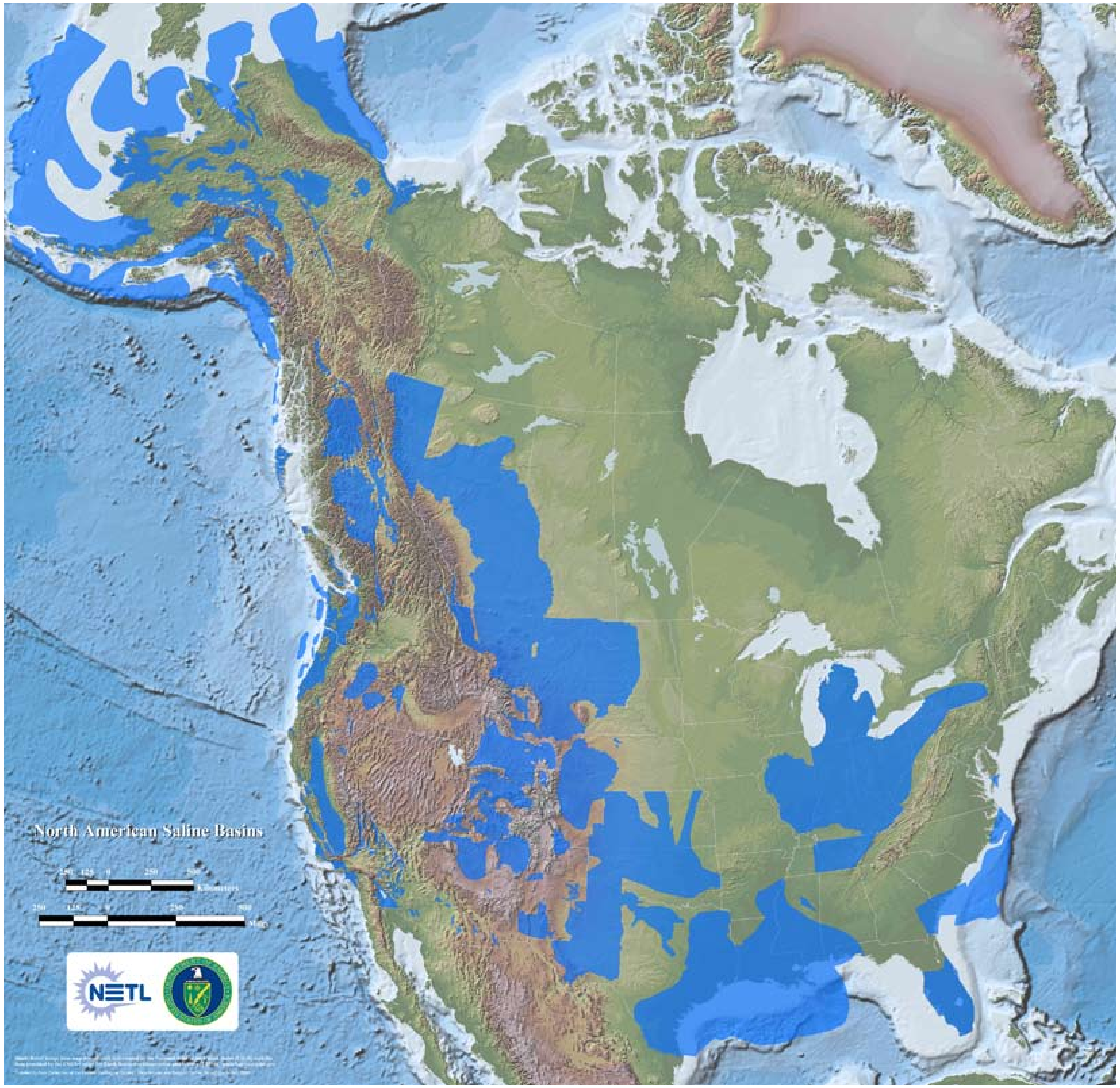
While not all potential areas of unmineable coal have been examined, the RCSPs have documented the location of 157–178 billion metric tons (173–196 billion tons) of CO_2 geologic storage potential in unmineable coal seams distributed over 24 states and 3 provinces. This is an increase of approximately 1 billion metric tons (1.1 billion tons) of identified storage from the previous version of the *Atlas*. For details on unmineable coal seam storage by state, see Appendix C.

CO_2 Storage Resource Estimates by Regional Carbon Sequestration Partnership for Unmineable Coal Seams

RCSP	Low: Billion Metric Tons	Low: Billion Tons	High: Billion Metric Tons	High: Billion Tons
BSCSP	12.1	13.3	12.1	13.3
MGSC	1.7	1.8	2.4	2.6
MRCSP	0.8	0.9	0.8	0.9
PCOR	10.7	11.8	10.7	11.8
SECARB	43.8	48.3	63.0	69.4
SWP	0.7	0.8	1.8	2.0
WESTCARB	86.8	95.7	86.8	95.7
TOTAL	157	173	178	196



This map displays coal basin data which were obtained by the RCSPs and other sources and compiled by NATCARB.



This map displays saline formation data which were obtained by the RCSPs and other sources and compiled by NATCARB.

Deep Saline Formations

Saline formations are layers of porous rock that are saturated with brine. They are much more extensive than coal seams or oil- and gas-bearing rock, and represent an enormous potential for CO_2 geologic storage. However, much less is known about saline formations because they lack the characterization experience that industry has acquired through resource recovery from oil and gas reservoirs and coal seams. Therefore, there is a greater amount of uncertainty regarding the suitability of saline formations for CO_2 storage.

While not all saline formations in the U.S have been examined, the RCSPs have documented the locations of saline formations with an estimated CO_2 sequestration potential ranging from 3,300 to more than 12,000 billion metric tons (from 3,600 to more than 13,000 billion tons). This is an increase of 2,000 to 9,000 billion metric tons (2,200 to 10,000 billion tons) of identified CO_2 storage from the previous version of the *Atlas*. For details on deep saline formation storage by state, see Appendix C.

CO_2 Storage Resource Estimates by Regional Carbon Sequestration Partnership for Saline Formations

	Low		High	
RCSP	Billion Metric Tons	Billion Tons	Billion Metric Tons	Billion Tons
BSCSP	460.9	508.0	1,831.5	2018.9
MGSC	29.2	32.1	116.6	128.6
MRCSP	49.6	54.7	199.1	219.5
PCOR	185.6	204.6	185.6	204.6
SECARB	2,274.6	2,507.3	9,098.4	10029.3
SWP	92.4	101.9	368.9	406.6
WESTCARB	204.5	225.4	818.2	901.9
TOTAL	3,297	3,634	12,618	13,909

Future Geologic Sequestration Options

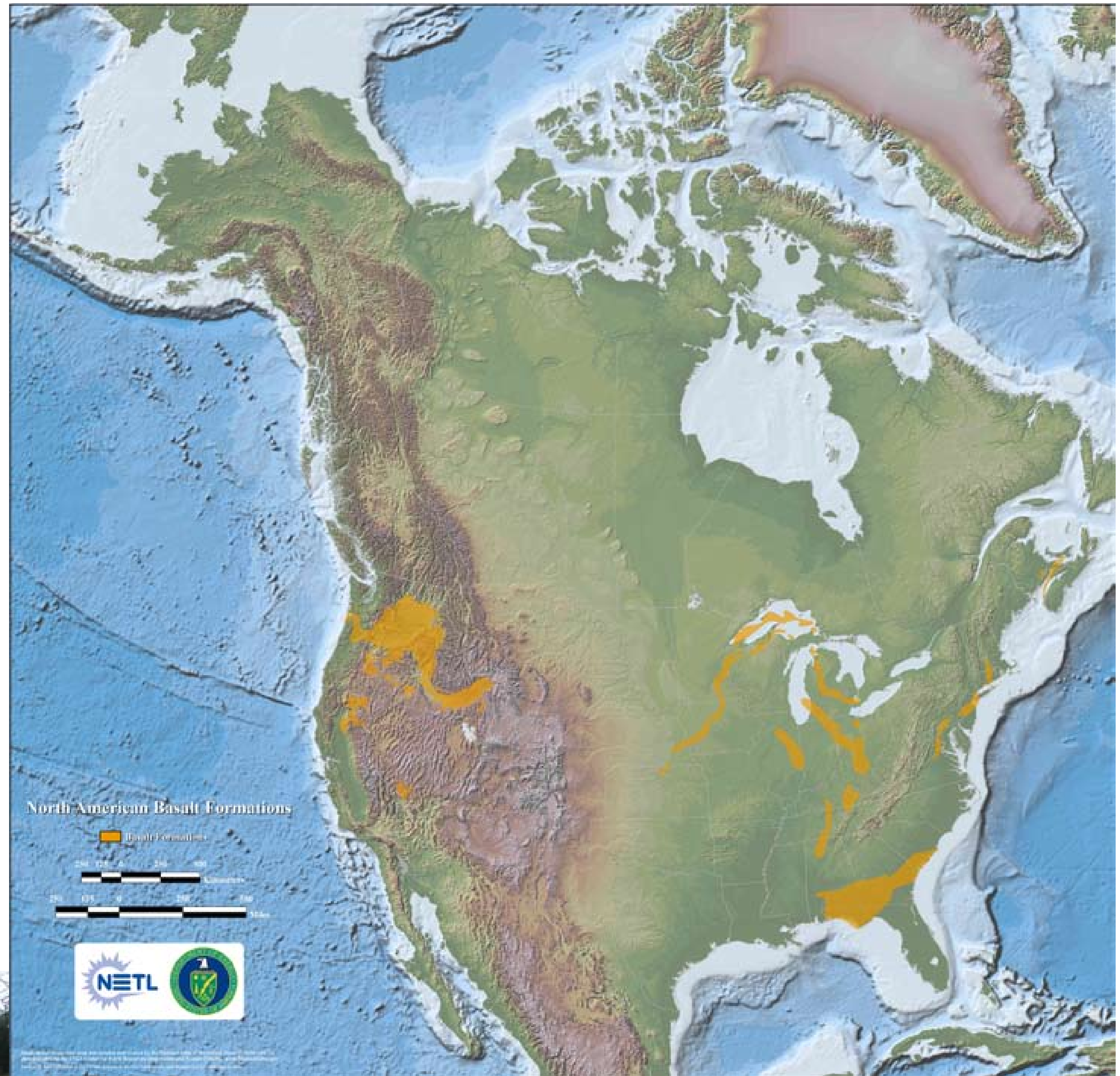
Other possible geologic sequestration options include basalts and shale formations.

Basalt Formations

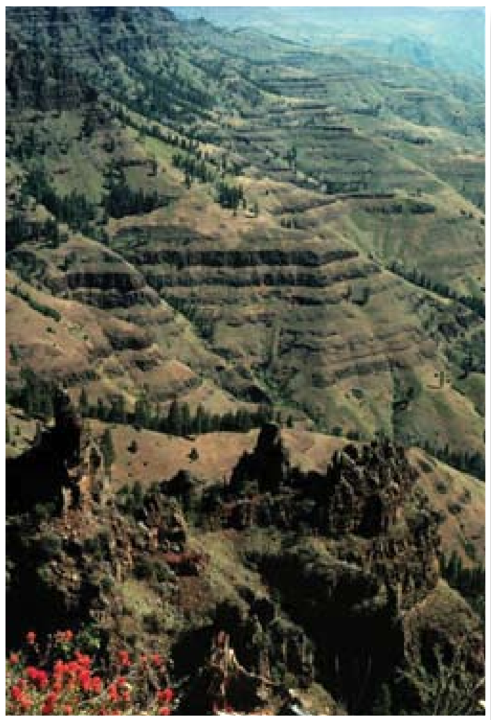
Basalt formations are geologic formations of solidified lava. Basalt formations have a unique chemical makeup that could potentially convert all of the injected CO_2 to a solid mineral form, thus isolating it from the atmosphere permanently. Research is focused on enhancing and utilizing the mineralization reactions and increasing CO_2 flow within a basalt formation.

Organic Rich Shales

Shale, the most common type of sedimentary rock, is characterized by thin horizontal layers of rock with very low permeability in the vertical direction. Many shales contain 1–2 percent organic material in the form of hydrocarbons, which provide an adsorption substrate for CO_2 storage similar to CO_2 storage in coal seams. Research is focused on achieving economically viable CO_2 injection rates, given the shales' low permeability.



This map displays basalt formation data which were obtained from the RCSPs and other external sources and compiled by NATCARB.



Columbia River Basalt.

Devonian Ohio shale in Eastern Kentucky.

Terrestrial Sequestration

Terrestrial sequestration is CO_2 uptake by soils and plants, both on land and in aquatic environments such as wetlands and tidal marshes. Terrestrial sequestration provides an opportunity for low-cost atmospheric CO_2 reductions and usually offers additional benefits such as habitat and/or water quality improvements. Terrestrial CO_2 sequestration efforts include tree-plantings, no-till farming, wetlands restoration, land management on grasslands and grazing lands, fire management efforts, and forest preservation. More advanced research includes the development of fast-growing trees and grasses and deciphering the genomes of carbon-storing soil microbes. NETL's Program efforts in the area of terrestrial sequestration include a focus on increasing carbon uptake on mined lands and quantifying sequestration benefits of growing biomass for power generation. These activities complement research into afforestation and agricultural practices that are being led by the U.S. Department of Agriculture (USDA). The U.S. DOE's Office of Science, the U.S. EPA, and the Department of the Interior are also involved in terrestrial sequestration in supporting and complementary roles.

The RCSPs are implementing 11 terrestrial sequestration field projects during the Validation Phase on abandoned mine land, wetlands, agricultural fields, prairie lands, and forests to validate the best practices for the enhancement of these sinks to store carbon emitted from distributed sources such as automobiles. The projects are measuring the effects on carbon storage from reclaiming damaged lands and altering land-use management practices which are designed to increase the storage rate in above and below ground carbon stocks and reduce the release of stored carbon by minimizing disturbance to the soils. Many of these projects will help to develop the MVA protocols to allow the carbon stored in these terrestrial ecosystems to be credited as greenhouse gas emissions reduction on future trading markets.

United States Geological Survey

Development of Refined Geologic Carbon Sequestration Assessment Methodology

Complementing the approach used in this *Atlas*, the U.S. Geological Survey (USGS) is using USGS experience with oil and gas resource assessment to develop a methodology to quantify geologic storage capacity for CO_2. This methodology development, mandated by the Energy Independence and Security Act of 2007, will allow refinement of the estimates presented in this *Atlas* as well as incorporation of uncertainty in capacity estimates. Having refined estimates will assist policy and decision makers in the future as they address mitigation strategies for global climate change.

The quantitative and probabilistic USGS resource assessment methodology will evaluate CO_2 storage resources in oil and gas reservoirs and saline formations. Storage in unmineable coal seams, which is included in the resource estimates of this *Atlas*, will not be addressed in this initial USGS methodology. Other potential storage reservoirs, such as organic-rich shales and terrestrial storage, are also excluded at this time. It should be noted that the product of the current USGS work is a methodology only. Substantial additional work would be required to apply the USGS methodology to all of the areas evaluated in this *Atlas.*

The assessment methodology will build upon the principles of USGS geologic oil and gas resource evaluation and assessment (Klett et al., 2003; Schmoker and Klett, 2003; Charpentier and Klett, 2003). This methodology has been extensively peer-reviewed (American Association of Petroleum Geologists Committee on Resource Evaluations (CORE) Subcommittee, 1999, 2000) and has been applied in a standardized manner to domestic and international basins and provinces. The methodology will produce probabilistic volume calculations based upon volume ranges (sizes and numbers of fields) and uncertainties as well as integrated risk factors (e.g., integrity of seals on local and regional scales, formation water displacement). It will define critical parameters necessary to determine geologic CO_2 sequestration reserves. The USGS methodology is being developed by an integrated and complementary team of geologists, hydrologists, geochemists, and assessment methodology scientists.

Two assessment unit test cases are underway to develop and evaluate the methodology: the Tensleep Formation (storage) and Phosphoria and Park City Formations (seal) in the Wind River Basin of Wyoming; and the Frio Formation (storage) and Anahuac Formation (seal) of the Gulf Coastal Plain of Texas. These test cases were selected because storage formations and seals can be evaluated as an integrated storage assessment unit. Data relevant to storage in the depth range of 1–4 km are available from proprietary databases, State surveys and agencies, oil and gas operators, and published sources to estimate storage efficiency, reactivity of aqueous phases, and regional flow of formation water.

For each test case, geologic and hydrogeochemical frameworks will be based on work completed for the USGS National Oil and Gas Assessment project and regional groundwater flow studies. The geologic framework will be based on stratigraphy, depositional environments, diagenetic history, mineralogy of storage areas and seals, structural history, and types of known traps. Input parameters for the hydrogeochemical framework will include formation water chemistry, information on regional flow systems, evidence for compartmentalization, drive mechanisms for hydrocarbon production, and predicted reactivity of formation water, seals, and storage units to CO_2.

Another important part of the methodology will be the identification of risk factors. Risk factors will be evaluated on a numeric scale and independent risks will be combined mathematically to determine the overall risk of storage in traps and saline formations. Risks include those identified in the methodology used in this *Atlas*: (1) seal integrity based on petroleum geochemistry, seal thickness and homogeneity, presence of faults, potential for seismic activity, and hydrologic regime; and (2) seal capacity estimated from known hydrocarbon column heights and capillary injection pressures. However, there are other risk factors that will be identified as the methodology develops, such as limits on injectivity and potential displacement of formation water into shallow aquifers. The results of the test cases will be probabilistic ranges of the storage capacity in traps (oil and gas reservoirs) and in the saline formation of the assessment unit. The numeric risk factor will then be used to adjust the ranges of storage capacity for level of risk.

In summary, the USGS is developing a peer-reviewed methodology that will allow refinement of the CO_2 storage resource estimates presented in this *Atlas.* The USGS and DOE are cooperating in this effort in order to provide policy makers with increasingly reliable information for climate-change-relevant policy discussions and decisions.

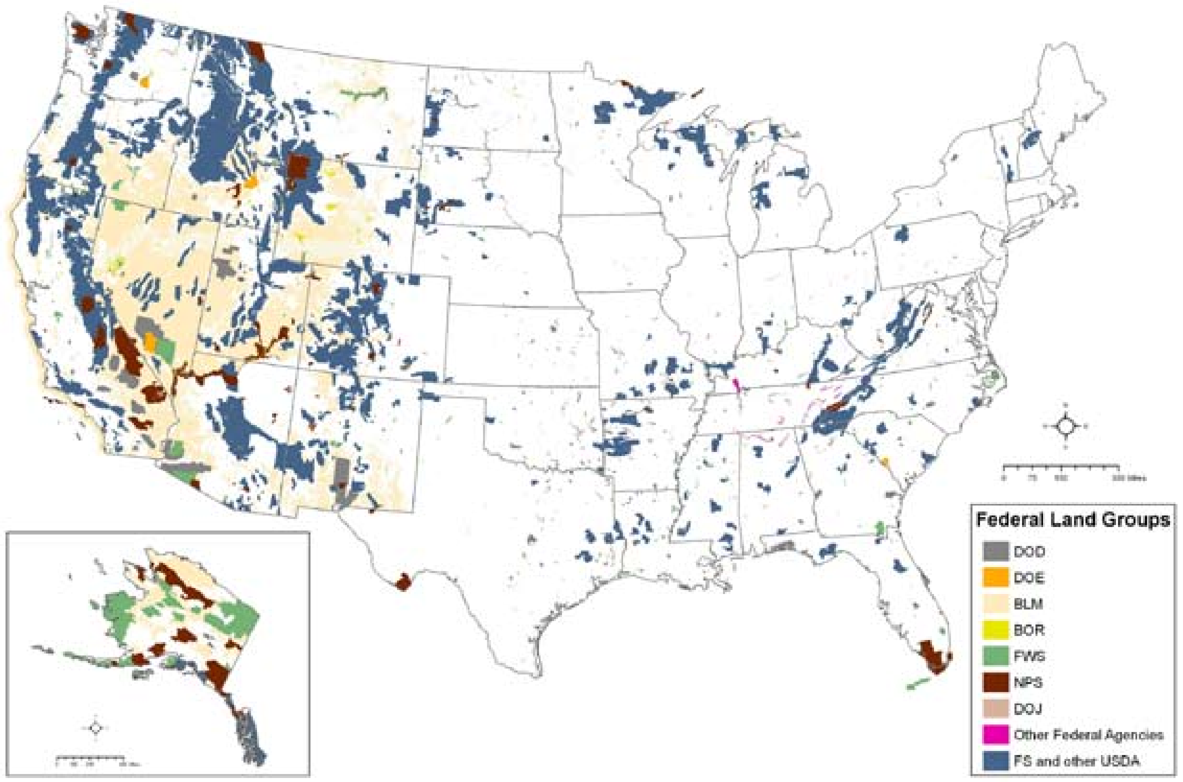


Figure 1. Federal Land Groups

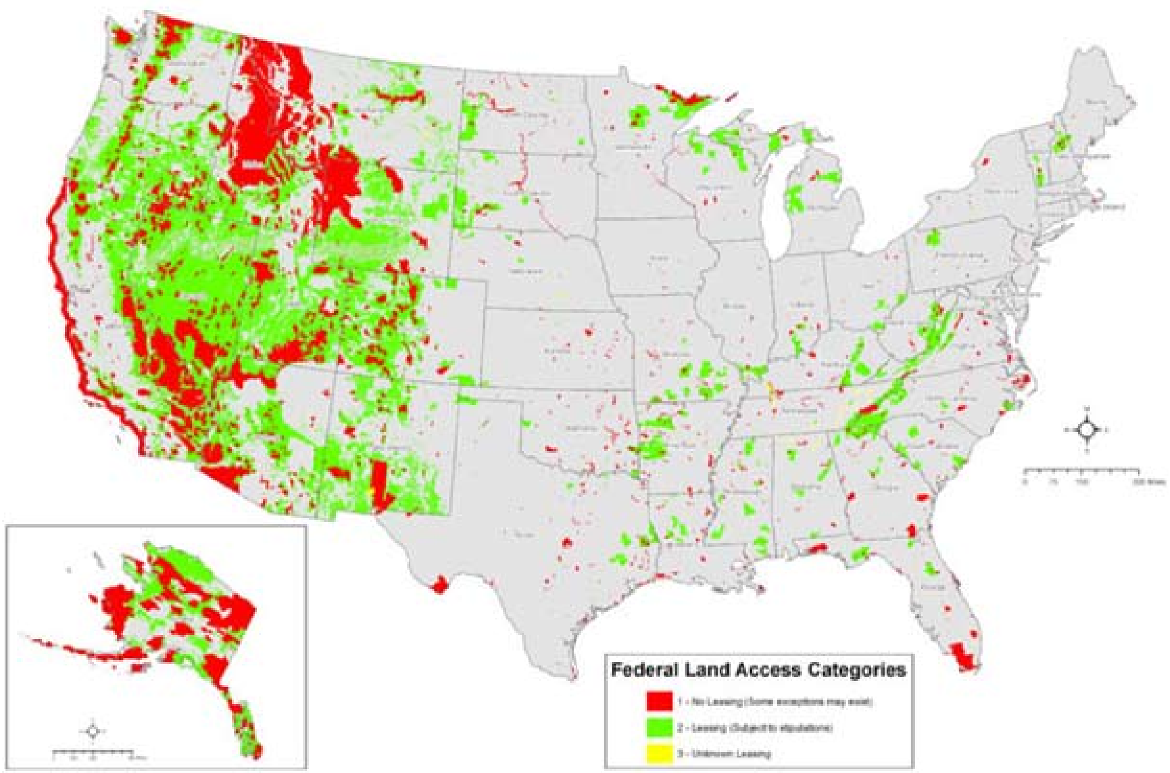


Figure 2. Federal Land Access Categories

Federal Land

Land Management

The Federal Government owns about 2.91 million km^2 (1.13 million mi^2) of land, almost 30 percent of the total U.S. land mass. A recent study used an existing USGS spatial shapefile to identify lands owned and/or administered by the Federal Government. The source dataset categorizes Federal landholdings under 65 separate government bodies. However, to obtain a manageable description of Federal landholdings, these 65 categories were reorganized into 9 land groups according to common Department or Agency (see Figure 1): (1) Department of Defense (DOD); (2) DOE; (3) Bureau of Land Management (BLM); (4) Bureau of Reclamation (BOR); (5) U.S. Fish and Wildlife Service (FWS); (6) National Park Service (NPS); (7) Department of Justice (DOJ); (8) other Federal Agencies; and (9) U.S. Forest Service (FS) and other USDAs. The BLM and the FWS, both in the Department of Interior (DOI), and the FS, of the Department of Agriculture, manage the vast majority of Federal acreage—about 2.45 million km^2 (0.95 million mi^2).

An assessment of Federal leases with respect to oil and gas resources, per Section 364 of the Energy Policy and Conservation Act (EPCA) of 2005, was recently completed by the DOI. Utilizing this study, it was recognized that certain agencies do not lease or are restricted from leasing lands under their management—for example NPS or FWS lands—and a net value of 1.62 million km^2 (0.63 million mi^2) was derived. This distribution is illustrated in Figure 2.

The BLM and the FS manage almost 99 percent of the leasable lands, 1.60 million km^2 (0.62 million mi^2), the vast majority of which is located in the Rocky Mountain States and further west. Potentially leasable lands from the BLM and FS are listed in Table 1. Additional restrictions may be added for the protection of wildlife and ecosystems as described in the study.

Table 1. Leasable Federal Lands (million km^2)

RCSP	BLM	USFS	*Total*
BSCSP	0.11	0	0.11
MGSC	0	0.01	0.01
MRCSP	0	0.04	0.04
PCOR	0.03	0.08	0.11
SECARB	0	0.08	0.08
SWP	0.17	0.16	0.33
WESTCARB	0.64	0.28	0.92
TOTAL	0.95	0.65	1.60

CO_2 Storage Resource

The estimated CO_2 storage resource beneath leasable Federal Lands is between 127 and 374 billion metric tons (140 and 412 billion tons) (Table 2). This is about 5.5 percent of the onshore CO_2 storage resource presented in this *Atlas*.

Table 2. CO_2 Storage Resource Beneath Federal Lands

	Low		High	
	Billion Metric Tons	Billion Tons	Billion Metric Tons	Billion Tons
Oil & Gas	32	35	32	35
Coal	4	5	5	6
Saline	91	100	337	371
TOTAL	127	140	374	412

A third of the potential CO_2 storage resource for oil and gas reservoirs is found beneath Federal Lands. Only 2.5–5 percent of the CO_2 storage resource for unmineable coal seams and saline formations can be found beneath Federal Lands. These values and percentages represent potential, and the numerical value will most likely shrink as these resource values are proved-up by storage reservoir characterization prior to actual injection.

The location of CO_2 storage resource beneath Federal Lands and stationary emission sources are listed by RCSP in Table 3. The majority of leasable Federal Lands is found in PCOR Partnership and SWP, while the majority of CO_2 storage resource can be found in BSCSP and WESTCARB. However, the emissions from MRCSP and SECARB are more than double those found in the SWP, BSCSP, and WESTCARB.

Table 3. Federal Lands CO_2 Storage Potential and Stationary Sources

RCSP	Percent of Leasable Acreage	Percent of Average Storage[1]	Number of Stationary Sources[2]	Annual CO_2 Emissions[3]
BSCSP	7.5	45.8	231	160
MGSC	0.4	1.0	399	660
MRCSP	2.5	4.8	580	800
PCOR	6.6	21.9	667	500
SECARB	5.2	9.8	785	1070
SWP	20.2	8.2	362	440
WESTCARB	57.3	8.4	135	200

[1] Of High and Low estimate of CO_2 storage resource
[2] Emit >10,000 Mt/yr and within 100 miles of leasable Federal Land
[3] Million metric tons/year

The advantage of using Federal Lands for CO_2 storage field projects in the western states is the ability to assemble sufficient land from a single owner. Federal Lands east of the Mississippi occur in smaller, more disseminated blocks, and its utilization here will most likely be in conjunction with non-Federal Lands.

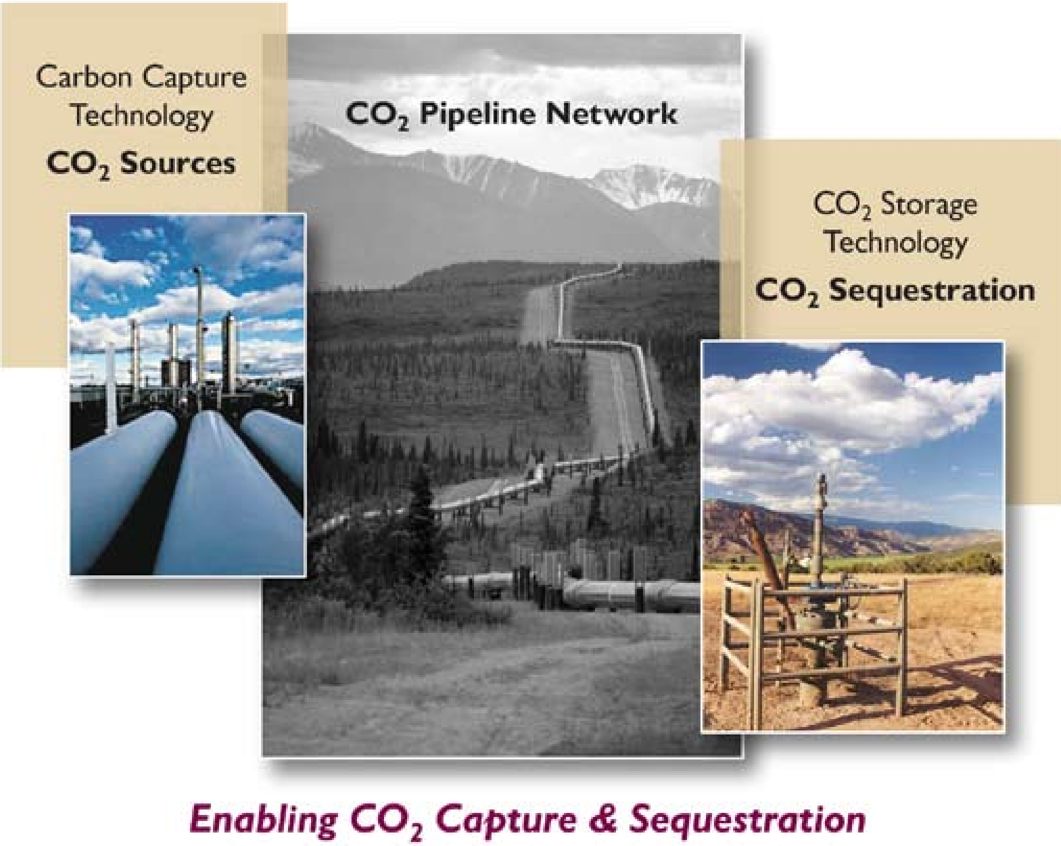
Distribution of CO_2 storage resource beneath Federal Land for oil and gas reservoirs, unmineable coal seams and saline formations is illustrated in Table 4.

Table 4. Distribution of CO_2 Storage Resource Beneath Federal Lands by Type and RCSP

Oil & Gas	**Low**		**High**	
RCSP	**Billion Metric Tons**	**Billion Tons**	**Billion Metric Tons**	**Billion Tons**
BSCSP	3.2	3.5	3.2	3.5
MGSC	0.0	0.0	0.0	0.0
MRCSP	2.8	3.1	2.8	3.1
PCOR	25.4	27.9	25.4	27.9
SECARB	0.5	0.6	0.5	0.6
SWP	0.0	0.0	0.0	0.0
WESTCARB	0.0	0.0	0.0	0.0
TOTAL	31.8	35.1	31.8	35.1

Unmineable Coal Seams	**Low**		**High**	
RCSP	**Billion Metric Tons**	**Billion Tons**	**Billion Metric Tons**	**Billion Tons**
BSCSP	0.1	0.1	0.2	0.2
MGSC	0.0	0.0	0.0	0.0
MRCSP	0.0	0.0	0.0	0.0
PCOR	1.7	1.9	1.7	1.9
SECARB	2.7	3.0	3.8	4.2
SWP	0.0	0.0	0.1	0.1
WESTCARB	0.0	0.0	0.0	0.0
TOTAL	4.5	5.0	5.8	6.4

Saline Formations	**Low**		**High**	
RCSP	**Billion Metric Tons**	**Billion Tons**	**Billion Metric Tons**	**Billion Tons**
BSCSP	48.2	53.0	188.0	206.8
MGSC	1.1	1.2	4.5	5.0
MRCSP	6.4	7.0	6.4	7.0
PCOR	8.2	9.0	32.8	36.1
SECARB	8.6	9.5	34.5	38.0
SWP	8.9	9.8	34.6	38.1
WESTCARB	9.1	10.0	35.9	39.5
TOTAL	90.5	99.5	336.7	370.5



CO_2 Pipeline Studies at NETL

Carbon dioxide transportation, a critical component of CCS, must be addressed in detail for successful deployment of CCS technologies. Should CCS legislation be enacted, stationary sources will be required to incorporate CO_2 capture technologies; thus a network of CO_2 pipelines will be essential for efficient and cost-effective transportation of CO_2. Linking CO_2 capture and geologic storage technologies through pipelines is a key focus of DOE's Carbon Sequestration R&D efforts.

A two-phase CO_2 Pipeline Infrastructure Study, "Developing a National CO_2 Pipeline Network," is being funded by DOE. Phase I of the study, completed in 2008, identified and analyzed the opportunities and benefits that would accrue from developing a national CO_2 pipeline network, the challenges facing such development, and the enhancement of new markets and technologies for all CCS process steps. The Phase II of the study, initiated in Spring 2008, is performing regional case studies to determine the pipeline routes that are most likely to develop to efficiently deliver CO_2 emissions from stationary sources to the nearest viable and economical geologic storage sites.

Phase I Results

If CO_2 emission reduction regulation is enacted, existing stationary sources will need to capture and sequester a portion of the 3,700 million metric tons of CO_2 emitted per year from stationary sources identified by the RCSPs. New dedicated pipelines, new codes and regulations and a new unambiguous classification of CO_2 will have to be established for safe, efficient transportation of CO_2 from these stationary sources to various geologic storage sites.

The cost of building these new pipelines will be substantial, and construction will not happen overnight. A coordinated approach backed by appropriate policy and legislation at the state and national levels will be necessary to encourage the construction of a national pipeline infrastructure. Even with uncertainties about the suitability of various geologic formations for long-term storage, the fact that major stationary sources are located close to potential geologic storage sites supports the development of a CO_2 pipeline network in stages. Without CCS, pipelines for EOR will continue to be built, but the pace of development will be market driven; with CCS, the first stage of development will likely involve building pipelines of 50 miles or less in length from stationary sources to geologic storage sites. In some situations, CO_2 may need to be transported hundreds of miles to reach a viable storage site or be delivered to a depleted oil field for enhanced oil recovery. The next stage would take pipeline development farther away from stationary sources—both intrastate and interstate.

The evolution of the pipeline network will also be impacted by the status it is ultimately accorded—whether pipelines are designated as "common carriers" (open access to all users under equal requirements) or "contract carriers" (transportation provided to shippers who enter into contracts with the pipeline operator)—and which government department has the responsibility for regulating CO_2 pipelines.

Photo of point where CO_2 exits the underground pipeline that transports CO_2 from Beulah, ND to Weyburn, Saskatchewan (photo courtesy of PTRC and the IEA GHG Weyburn CO_2 Monitoring and Storage Project)

Phase II Update

The Phase II of the CO_2 pipeline study (anticipated to be completed in summer 2009), will perform regional case studies to determine the pipeline routes that are most likely to develop to efficiently deliver CO_2 emissions from stationary sources—especially from coal-fired power plants that account for the majority of emissions—to the nearest viable geologic storage sites. The implications of economics, resources, and timing of pipeline development will be evaluated. The study will also identify regional challenges and benefits to gain a better understanding of the regional differences and how these differences will affect CO_2 pipeline development. A mapped view of illustrative regional CO_2 pipeline networks will be created as a platform to determine future requirements for development of a national CO_2 pipeline network.

Statistics

- Approximately 3,700 miles of a CO_2 pipeline network were developed over 35 years.
- Approximately 320,000 miles of a natural gas transmission network and 1,215,000 miles of a natural gas distribution network were developed over 100 years.
- Approximately 123,000 tons per day of CO_2 is currently transported through pipelines.

Anadarko CO_2 pipeline to Salt Creek

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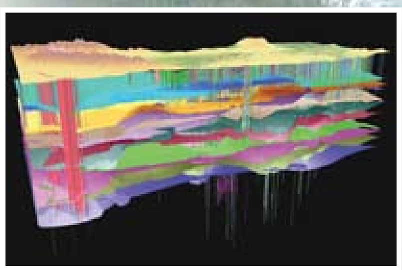
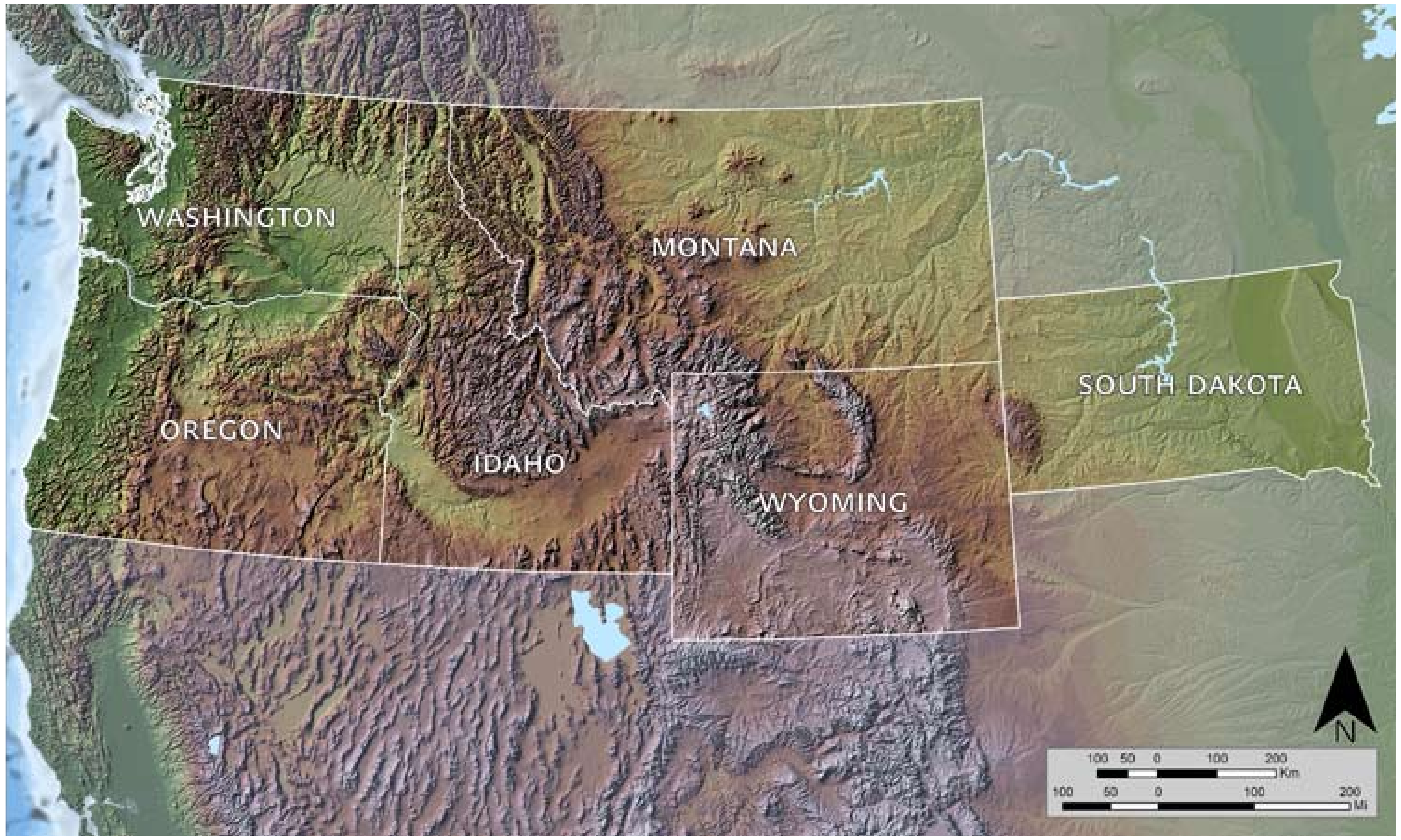
Regional Carbon Sequestration Partnerships Perspectives

Information contained in the following Regional Carbon Sequestration Partnership (RCSP) Sections was obtained from each RCSP. This information was collected and analyzed as part of the efforts of the RCSPs, and is not intended to be a comprehensive assessment. For additional information, please visit the RCSP websites (listed on page 8).



Credit: U.S. Fish and Wildlife Service



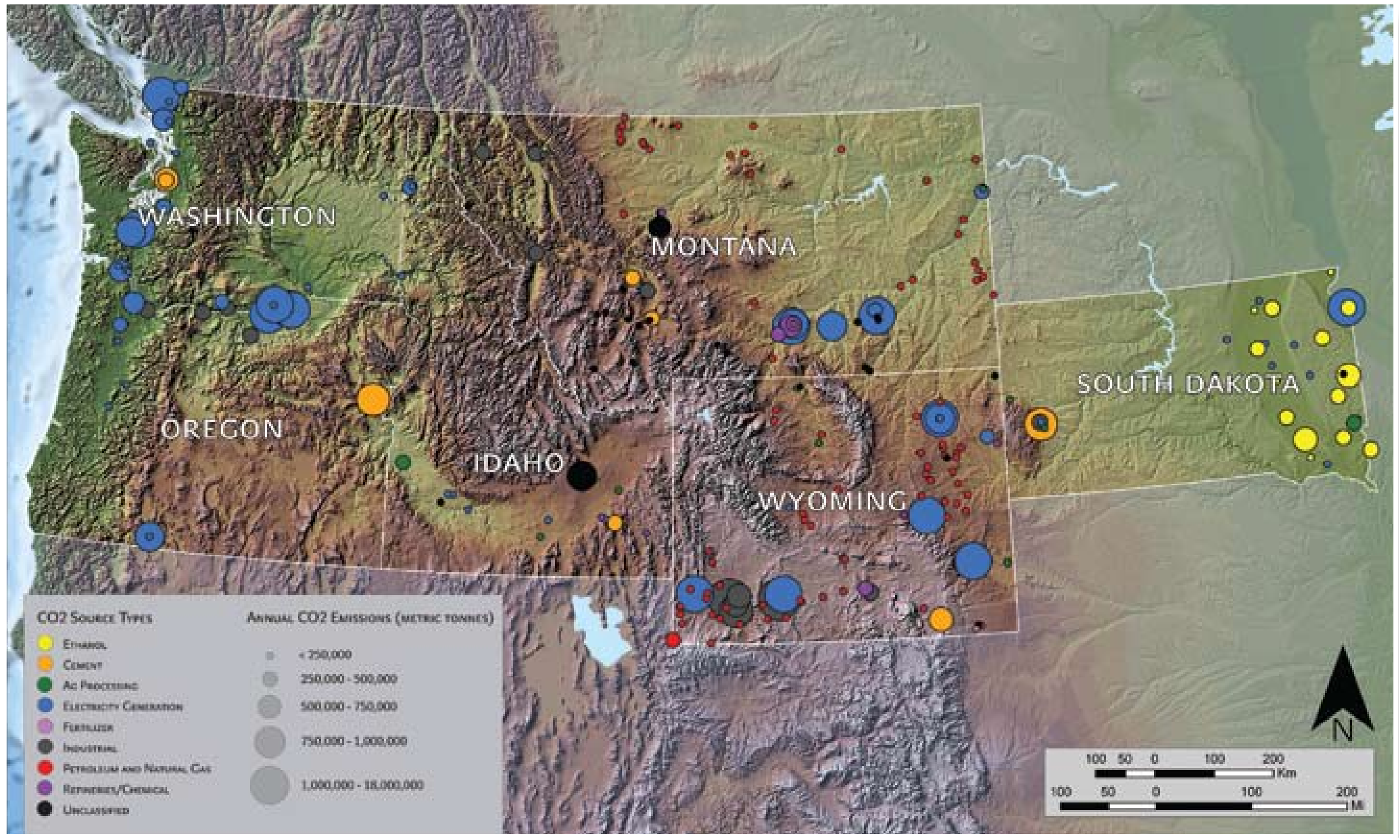
The Big Sky Carbon Sequestration Partnership (BSCSP) is working on developing effective, safe, and economical approaches for capturing and permanently storing CO_2 to reduce the nation's greenhouse gas emissions. The BSCSP relies on existing technologies from the fields of engineering, geology, chemistry, biology, GIS, and economics to develop novel approaches for both geologic and terrestrial carbon storage in this Region. The BSCSP also engages in economic and regulatory analyses, public education and outreach, and regional demonstration projects to deploy and evaluate new technologies.

The BSCSP is a coalition of more than 60 organizations including universities, national laboratories, private companies, state agencies, Native American tribes, and international collaborators. BSCSP partners are engaged in several aspects of the Validation Phase and Development Phase projects and contribute to Partnership efforts to deploy carbon sequestration in the BSCSP Region.

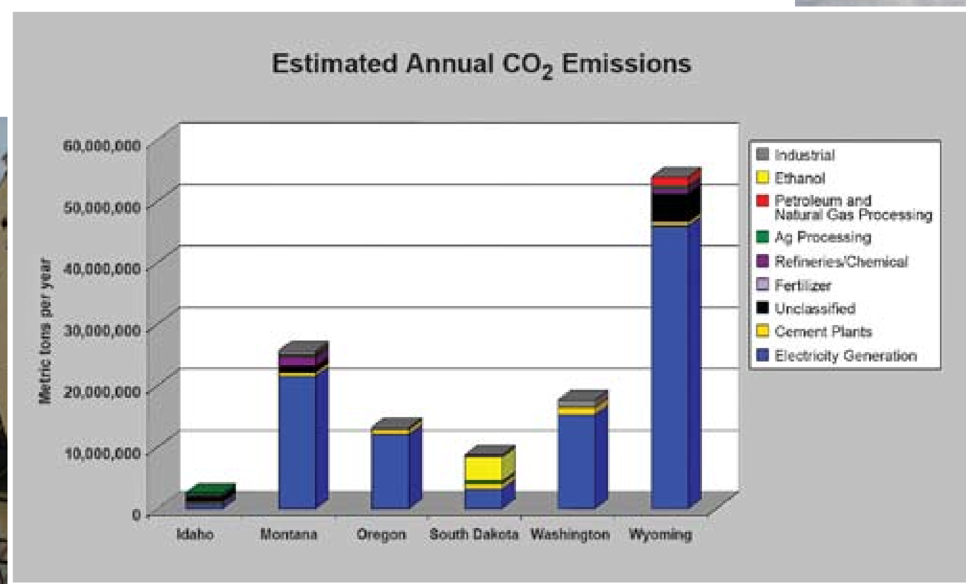
The BSCSP Region encompasses Montana, Wyoming, Idaho, South Dakota, and eastern Washington and Oregon. The regional characterization of potential CO_2 storage options conducted during Characterization Phase efforts confirmed that the Region holds a wealth of potential carbon sequestration sites. East of the Rockies there are large saline formations capable of sequestering large volumes of CO_2, while the western part of the Region has basalt formations which also have the potential to sequester many hundreds of years of regional CO_2 emissions. In addition, the BSCSP land area includes vast acreage of agricultural, range, and forest lands that can be managed for greater storage of soil carbon and carbon in biomass. The BSCSP Region is also rich in energy resources including coal, oil and gas, and renewable sources of energy.

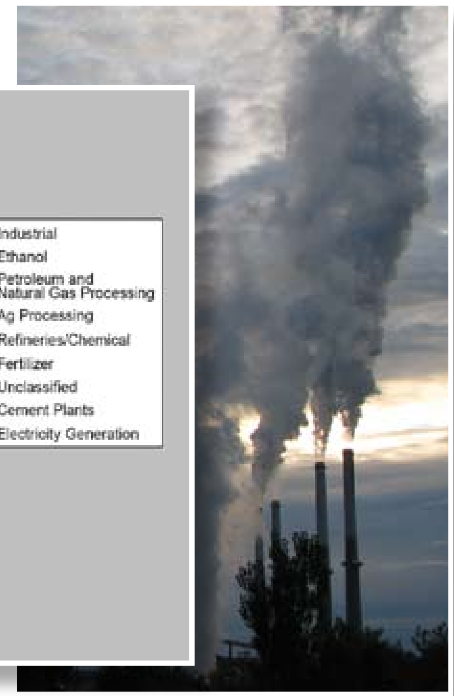
BSCSP Sources

The BSCSP estimates that their Region produces more than 119 million metric tons (131 million tons) of CO_2 from stationary sources annually, totaling approximately 4 percent of U.S. emissions. While the BSCSP Region currently produces only a small fraction of the CO_2 emissions in the United States, it is a key area for fossil fuel energy development and has one of the largest population growth rates in the nation. According to U.S. 2000 census data, the Region has a population of about 13 million people and has increased 16 percent from 1990 to 2000, with the greatest growth occurring in Idaho, Oregon, and Montana. South Dakota is the least populous state in the Region and also has the lowest CO_2 emissions. Washington State is the most populous state in the Region, but because of low industrial emissions and reliance on hydroelectric power, it only ranks third in CO_2 emissions. While Montana and Wyoming have relatively low populations, they are the greatest emitters of CO_2 because of numerous mining, industrial, and fossil fuel operations, in addition to a high dependence on coal-fired electric generation.

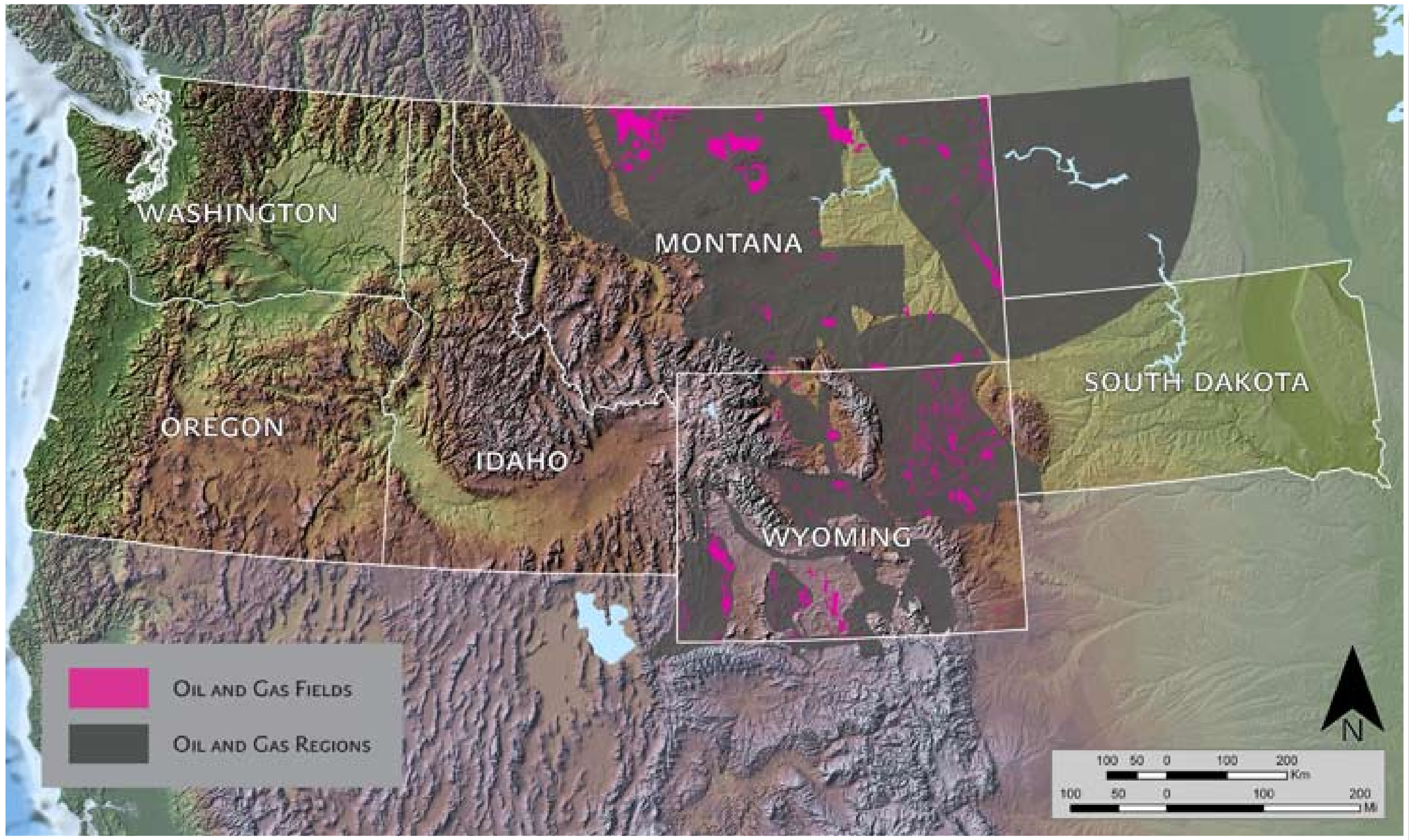


Eighty-one percent of estimated CO_2 emissions in the BSCSP Region are produced by coal-fired electric generation facilities, which produce 97 million metric tons (107 million tons) of CO_2 emissions annually. Montana and Wyoming combined produce 70 percent of these emissions. In these two states, cement production, ethanol production, and other industrial processes, such as aluminum production, emit 14 million metric tons (15 million tons) annually, accounting for 12 percent of the Region's emissions. Idaho, Oregon, and Washington contribute 28 percent of the Region's emissions from power generation plus cement, lime, and aluminum production. South Dakota produces about 4 million metric tons (4.3 million tons) annually from ethanol production. Unclassified sources, including diesel fuel use, production by-products from mining operations, and self-contained coal and natural gas power plants for large institutions account for an additional 8 million metric tons (9 million tons) of CO_2 annually which represents 6.5 percent of the Region's total. Mining of trona ore for soda ash, which is a commodity naturally occurring in the United States only in Wyoming's Green River Basin, produces 4.6 million metric tons (5.1 million tons) of CO_2 annually.





As part of ongoing activities, the BSCSP continues to update annual emissions estimates and stationary sources as new information becomes available. Work also continues to characterize the proximity of potential geologic sequestration sites in the vicinity of these stationary sources. This information, in conjunction with available infrastructure data (pipelines, EOR sites, right-of-ways, etc.), will be used to develop an interactive mapping tool for evaluating potential sequestration sites.



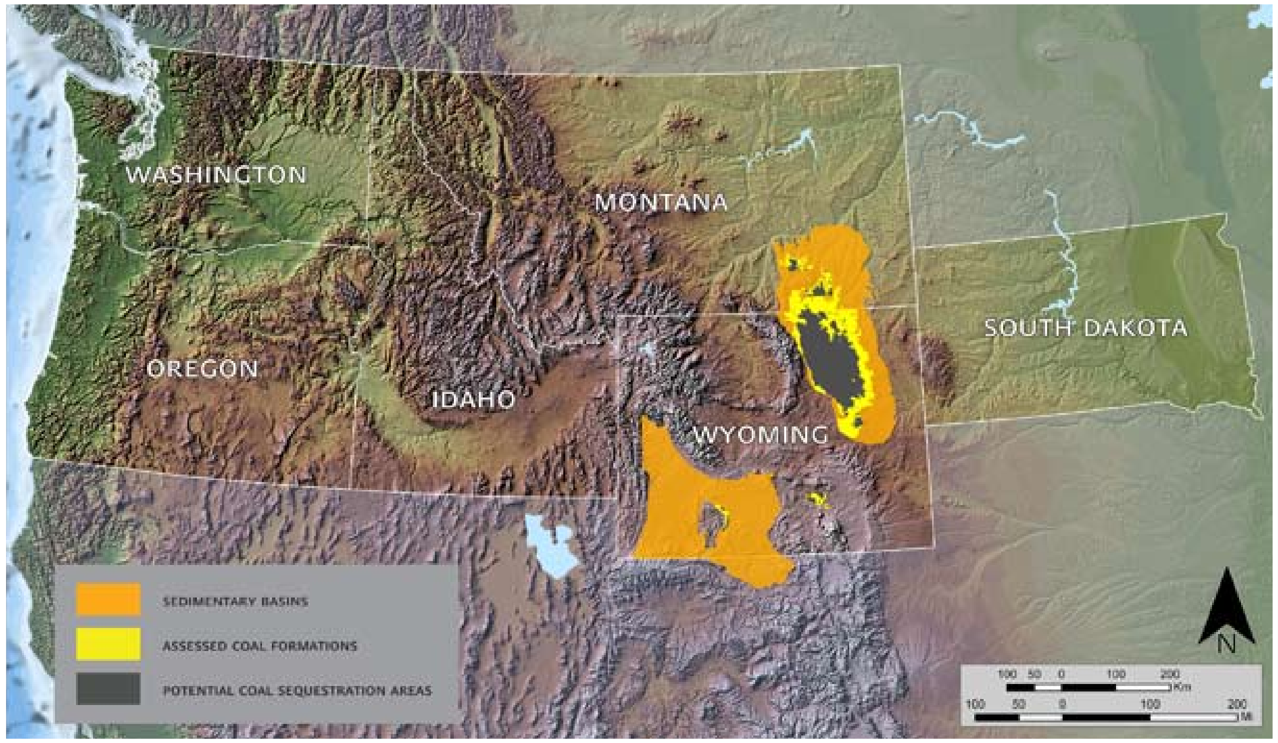
BSCSP Oil and Gas Reservoirs

Within the BSCSP Region mature oil and gas reservoirs have contained crude oil and natural gas for millions of years. These reservoirs are primarily located in the sedimentary basins of Wyoming and Montana. Based on cumulative oil production to date from these reservoirs, the Region could sequester an estimated 1.6 billion metric tons (1.8 billion tons) of CO_2.

The major oil and gas producing regions within the BSCSP area are: (1) the Williston Basin that covers the northeastern region of Montana as well as parts of South and North Dakota; (2) the Central Montana Uplift; (3) the Sweetgrass Arch in north-central Montana; (4) the Wind River Basin in central Wyoming; (5) the Bighorn Basin in north-central Wyoming and south-central Montana; (6) the Powder River Basin (PRB) that spans southeastern Montana and northeastern Wyoming; (7) the Laramie Basin in southeastern Wyoming; and (8) the Greater Green River Basin (GRB) in southwestern Wyoming. There are over 500 oil and gas fields in Montana and more than 1,400 in Wyoming. The largest of these fields could potentially sequester 129 million metric tons (142 million tons) of CO_2 which is greater than the Region's current annual CO_2 emissions.

Enhanced oil recovery offers an economic incentive for carbon sequestration in oil and gas reservoirs. Current EOR operations within the BSCSP Region include individual projects in the Green River, Wind River, and Powder River Basins that utilize CO_2 produced from a natural gas processing plant on the Moxa Arch in the western Green River Basin. Plans are in progress to expand the delivery of this CO_2 to many other fields within the Big Horn Basin, the Williston Basin, and the Laramie Basin. Additionally, the presence of large reservoirs trapping naturally occurring CO_2 in the BSCSP Region further demonstrates the long-term suitability of these basins for CO_2 storage.

BSCSP Coal Seams



The BSCSP has many coal seams throughout the Region that can be used for CO_2 sequestration. Although there are many coal basins within the Region, CO_2 storage resource estimates were focused on basins with the largest coal resources including the PRB and the GRB. Unmineable coal is generally defined as coal buried under 305 m (1000 ft) or more of overburden. The salinity of the water in a coal deposit is sometimes used as a guide for determining depth. However, the coal seams in the PRB, for example, have exceptionally fresh water and thus water salinity cannot be used as a reliable tool for determining coal depth or the unmineability of the coal.

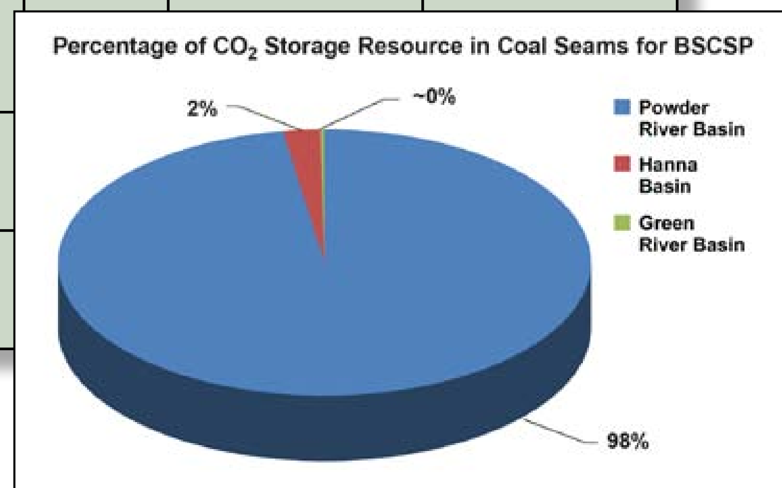
The nature of the PRB coal zone makes this basin exceptionally important for CO_2 sequestration in the BSCSP Region. The large unmineable area (below 305 m (1000 ft) has an average thickness of 22 m (73 ft). In addition to being thick, the coal seam also has high natural permeability, which describes how connected the pore spaces are within the coal deposit. High permeability ensures that once injected, CO_2 can flow throughout the pore network and fill all available pore spaces within the deposit. Also, during the CO_2 sequestration process, CO_2 molecules displace methane (CH_4) molecules from adsorption sites within the coal matrix. The CO_2/CH_4 displacement ratio for the subbituminous coal of the PRB is much higher than coals of higher rank, which suggests that the PRB may be an ideal location for a CO_2-sequestration-in-coal site. Carbon dioxide storage in unmineable coal seams is an attractive economic prospect due to ECBM recovery through injection of CO_2 into coal seams. The increased methane production resulting from this process helps to offset the cost of CO_2 capture and sequestration.

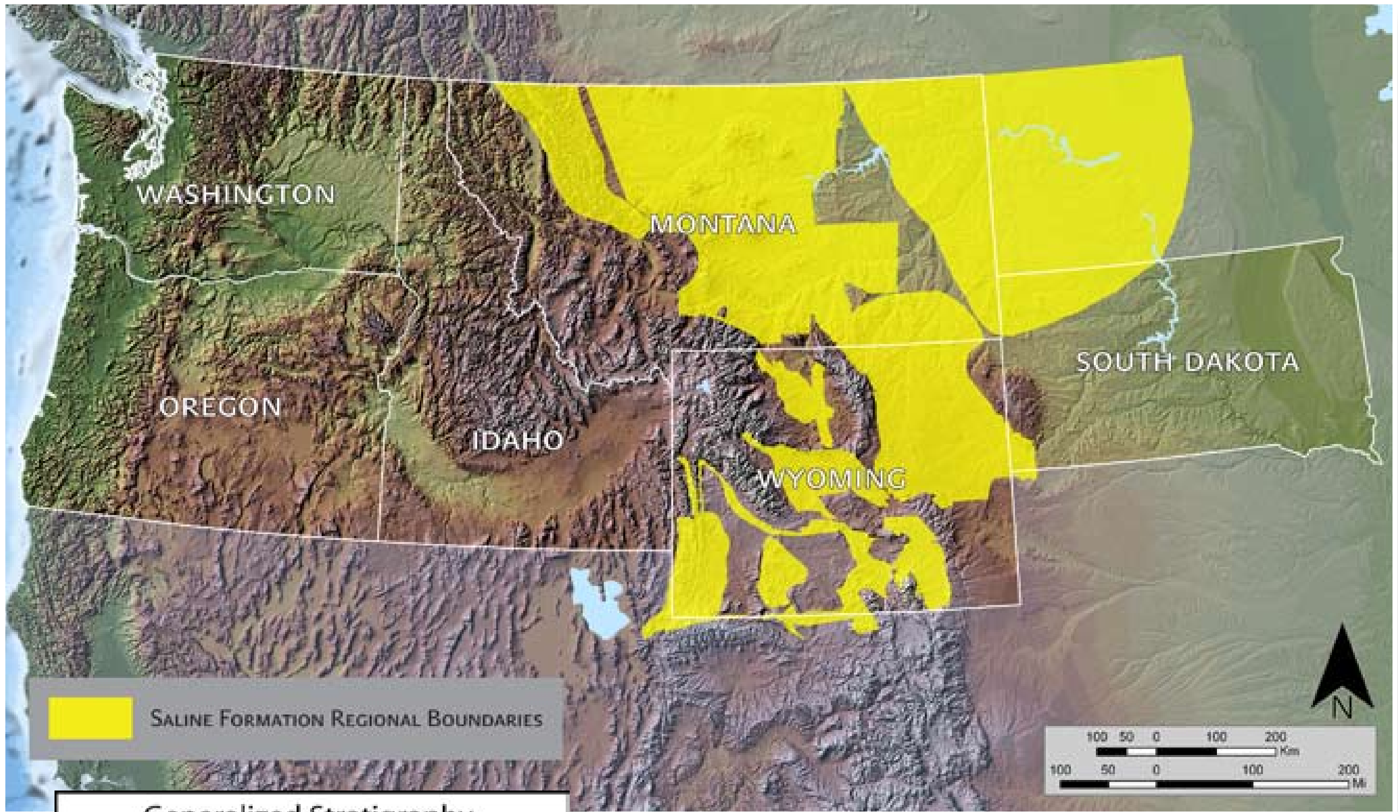
The PRB and GRB both contain significant coalbed methane resources. These resources are important economically for power generation; however, there is significant CO_2 storage potential within coal seams that are too deep or too thin to be economically viable as mineable resources. Coal formations in the PRB include the Knobloch and Rosebud coals in Montana, and the expansive Wyodak-Anderson coal formation which underlies most of northeastern Wyoming. Coal formations in the GRB, and Hanna Basin where assessed, include the Ferris, Hanna, Black Butte, Point of Rocks, and Johnson coalbeds.

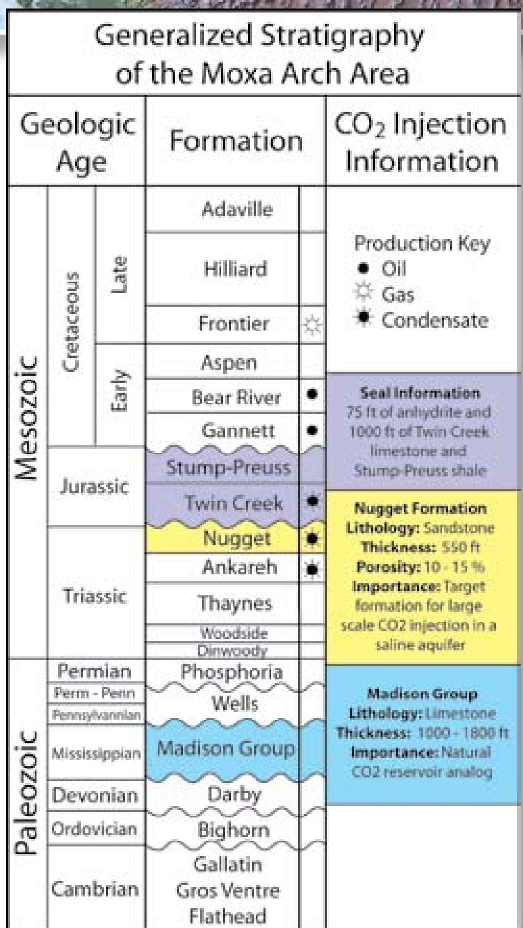
Coal Seam	Basin	State	Storage Volume (million metric tons)	Storage Volume (million tons)
Knobloch	Powder River Basin	Montana	133	147
Rosebud	Powder River Basin	Montana	140	154
Black Butte	Green River Basin	Wyoming	28	31
Point of Rocks	Green River Basin	Wyoming	16	18
Ferris	Hanna Basin	Wyoming	391	431
Hanna	Hanna Basin	Wyoming	180	198
Johnson	Hanna Basin	Wyoming	11	12
Wyodak-Anderson	Powder River Basin	Wyoming	11,500	12,701
Powder River Basin *Total million metric tons* *(Total million tons)*	11,800 (13,001)			
Hanna Basin *Total million metric tons* *(Total million tons)*	582 (641)			
Green River Basin *Total million metric tons* *(Total million tons)*	44 (49)			

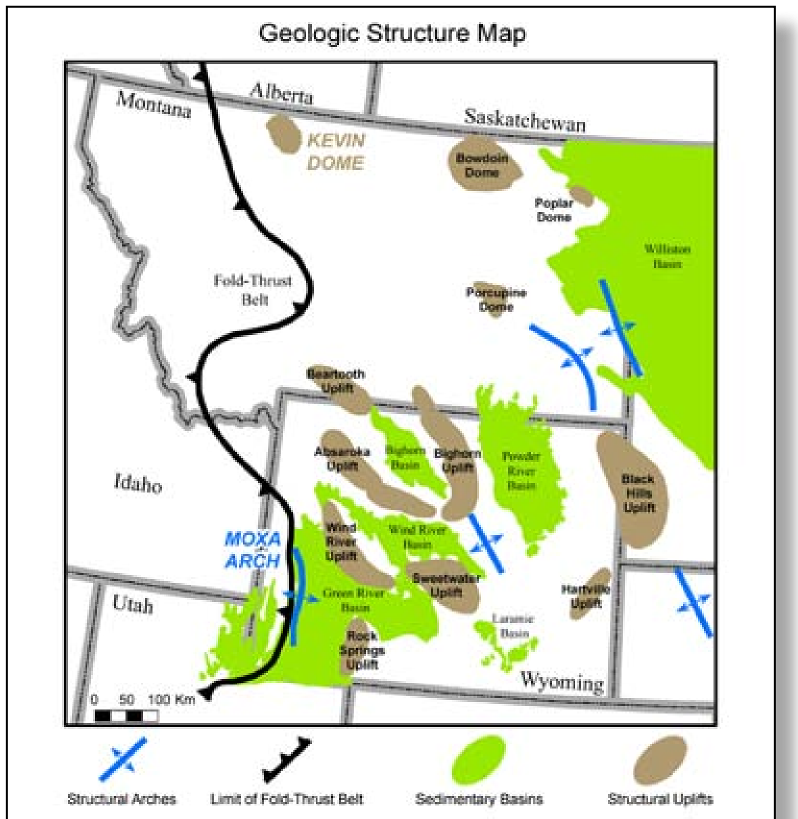
BSCSP calculations estimate that the total CO_2 storage resource in unmineable coal seams in the PRB is around 12 billion metric tons (13 billion tons), most of which represents storage area in the expansive Wyodak-Anderson coal field. Carbon dioxide storage resource estimates for the Hanna Basin are around 250 million metric tons (276 million tons), while the GRB has the potential to sequester 44 million metric tons (49 million tons) of CO_2.

The Rosebud coal seam in the northern Powder River Basin.





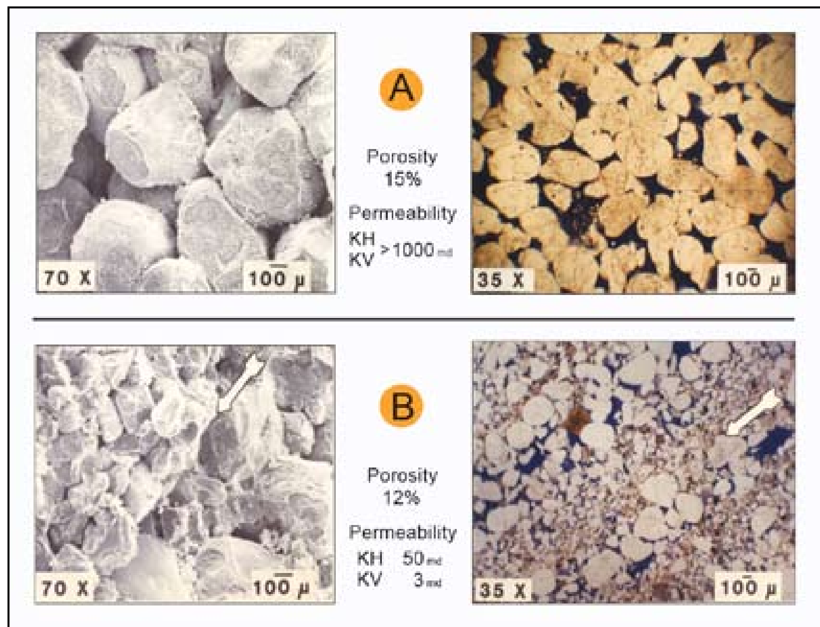




BSCSP Saline Formations

Saline formations throughout the BSCSP Region offer great potential for future sequestration activities. Extensive deep saline formations are present in Paleozoic and Mesozoic formations of Montana's and Wyoming's sedimentary basins. These basins account for greater than 3 million km^2 (750 million acres) underlain by sedimentary units potentially suitable for sequestration. BSCSP estimates that greater than 400 billion metric tons (441 billion tons) of CO_2 could be sequestered in the Region's saline formations, which is adequate for storing the Region's cumulative anthropogenic CO_2 for many years. Several of these formations currently host vast naturally occurring accumulations of CO_2, demonstrating the potential of these units to efficiently trap CO_2. BSCSP is studying naturally occurring CO_2 reservoirs in the Duperow Formation at Kevin Dome in northern Montana and the Madison Formation of the Moxa Arch in southwestern Wyoming as potential analogs for sequestration.

The Triassic / Jurassic Nugget Sandstone in southwest Wyoming is the target for the BSCSP Development Phase large-scale injection test. The Development Phase project will geologically characterize the site, construct pre-injection models of CO_2 flow in the sub-surface, inject up to 0.91 million metric tons (1 million tons) per year of CO_2 for 3 years, and monitor the injected CO_2. This saline formation is important regionally in that it has tremendous potential storage and is geologically similar to many other deep saline formations throughout the BSCSP Region and much of the West. This test will provide critical data towards developing a commercial-scale sequestration site in the Region.

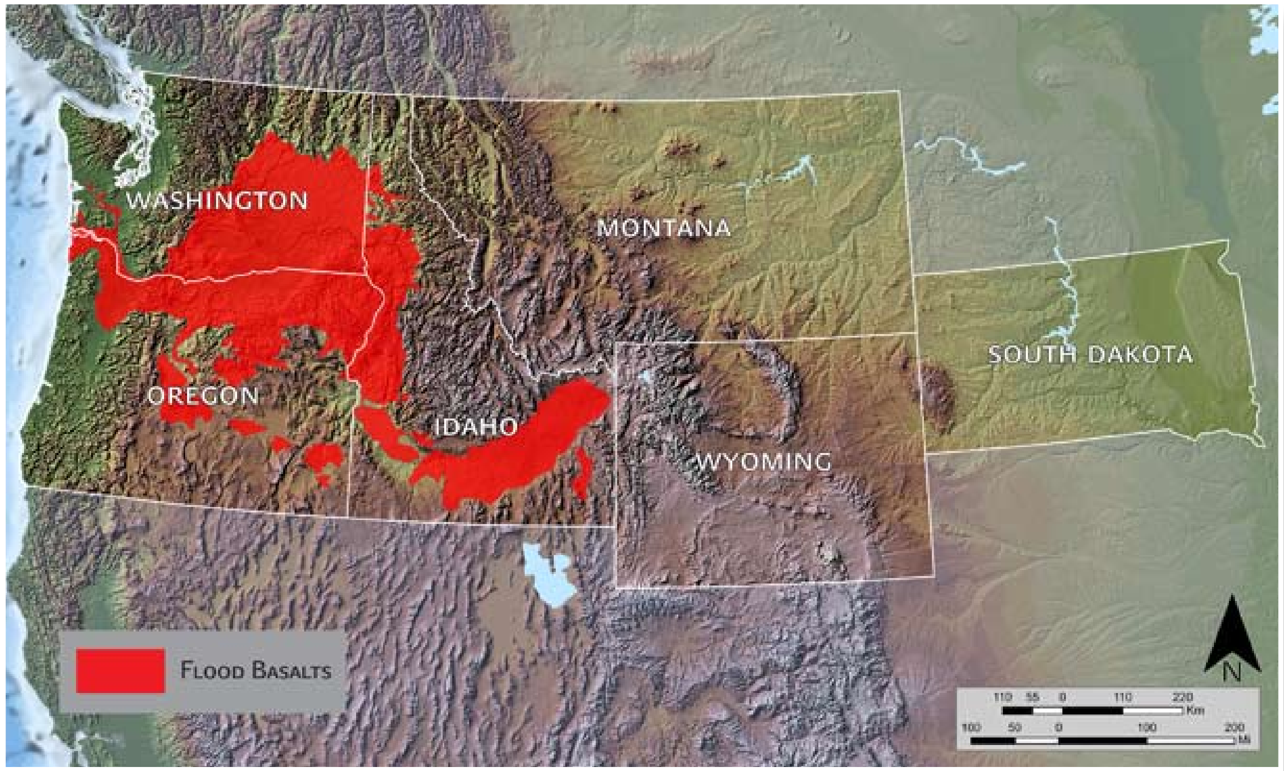


Photomicrograph showing porosity and permeability in the Nugget sandstone.

BSCSP Basalts

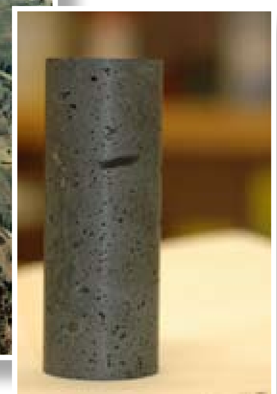
Regionally extensive mafic rock formations, flood basalts, are a distinguishing feature of the geology of the Pacific Northwest. The Region's Columbia River Basalt Group (CRBG) covers approximately 164,000 km^2 (63,300 mi^2). The CRBG, which is part of the larger Columbia Plateau Province, is probably the most well-studied igneous province in the world. There are over 300 lava flows that comprise CRBG. Each flow is from a few tens of meters to 100 m (328 ft) thick. Combined, the basalt formations offer significant long-term storage potential, with CO_2 storage estimates that range between 33–134 billion metric tons (36–148 billion tons). Large basalt formations are globally distributed, with estimates that the five largest basalt provinces could sequester 10,000 years of global CO_2 emissions. Basalt formations have a number of characteristics that are favorable for CO_2 storage including:

- Conducive mineralogy and chemical makeup for rapid *in situ* mineralization of CO_2
- Multiple very low permeability flow interior sections acting as caprock seals
- High porosity and permeability in interflow zones suitable for CO_2 injection



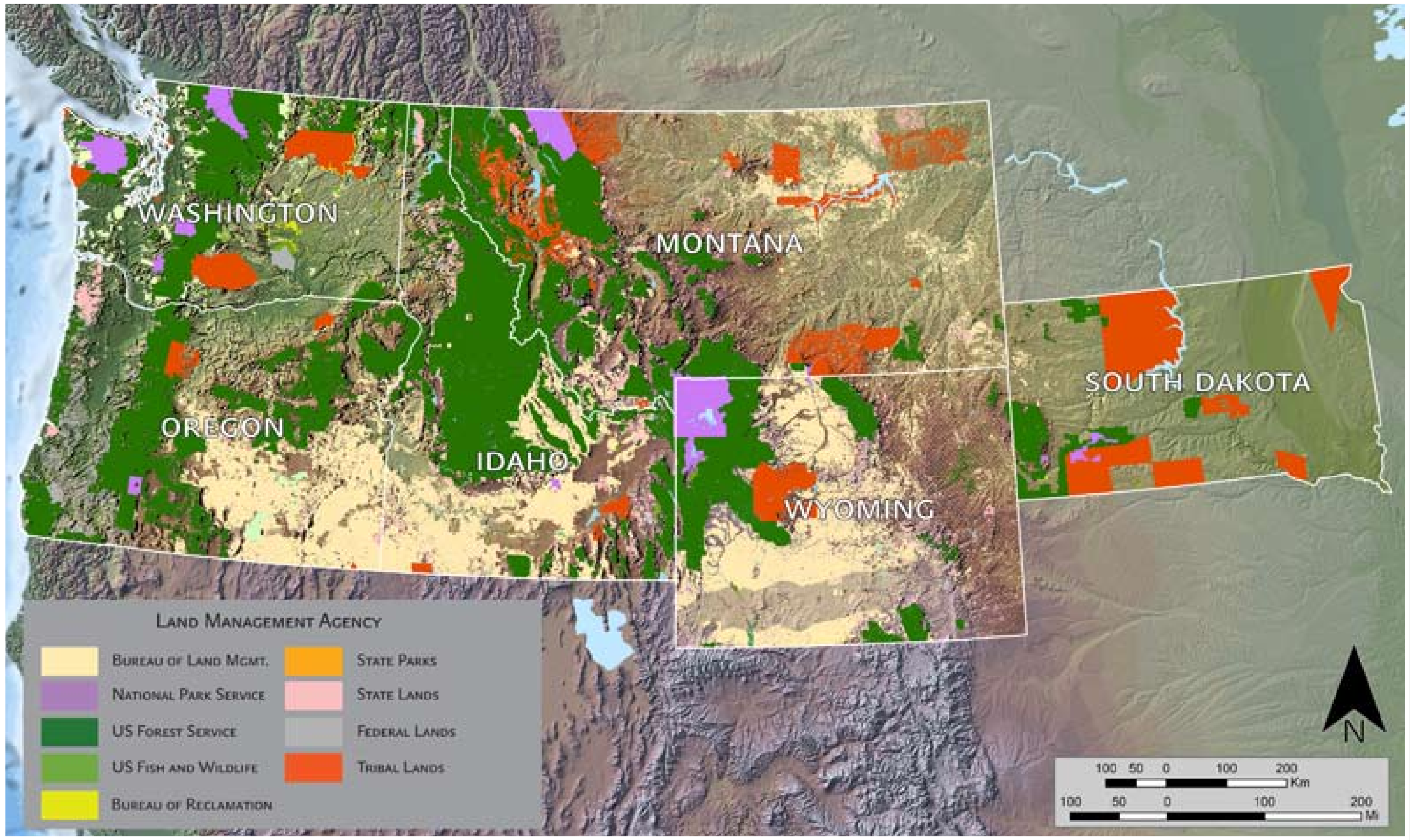
Although flood basalts have an inherently heterogeneous structure, there is ample evidence of km-scale lateral continuity in interflow zones where basalts serve as regional aquifer systems. For example, the CRBG contains several regional aquifer systems serving eastern Washington and north-eastern Oregon that consist of a layered series of highly conductive aquifer zones (darcy-level permeability) alternating with dense basalt zones of very low hydraulic conductivity. Wells have penetrated the thick sequence of basalt flow tops to meet irrigation, industrial, and public water supply needs since the early 1900s. These examples from shallow basalt aquifer systems are important because deeper basalts that are potential targets for CO_2 sequestration are expected to have similar regional-scale connectivity in some interflow zones that would be required for any commercial-scale CO_2 sequestration operation.

Thumper trucks deliver seismic energy to the subsurface to detect underground faults.



Basalt core sample.

A specialized three-component, quasi 3-dimensional seismic survey was completed in December 2007 at the proposed field site. Tomographic refraction statics, velocity analysis, and preliminary migration of the P-wave data show no evidence of significant faulting or vertical displacement within the image area. The results of the seismic processing reduce uncertainty with regard to the basalt structure and provide confidence for proceeding with the pilot in the proposed test area.



BSCSP Land Ownership

The core states of the BSCSP Region consist of a variety of land ownership and management entities which can affect carbon sequestration activities. The Region contains a high proportion of federal- and state-owned lands managed by various government agencies, all of whom retain different policies and regulations for permitting sequestration related activities on these lands. Private lands with split surface and subsurface estates further complicate this issue. Because of this, the sequestration potential of a specific site is not governed solely by geologic or technical issues but must engage the myriad of competing regulations and policies that govern both surface and subsurface regulatory frameworks.

The BSCSP Region contains large areas of federal land managed by the BLM, Bureau of Indian Affairs, DoD, DOE, FS, FWS, and U.S. Bureau of Reclamation, as well as many national parks, state parks, state wildlife management areas, and federal wildlife refuges. Many of these lands demonstrate the potential for carbon sequestration activities, but such activities will be unique to each site based on surface and subsurface ownership and regulatory frameworks that have only recently begun to emerge.

All of the core states in the BSCSP Region are in different stages of policy development for carbon sequestration activities on both private and public lands in addition to various split estate scenarios. The legislation governing these activities will be important for the viability of carbon sequestration in the Region. The BSCSP continues to work with state and federal agencies to develop a regulatory and policy framework that will ensure the safe and reliable storage of CO_2 under suitable geologic, social, economic, and environmental constraints.




National Parks, private farms, and large tracts of National forests demonstrate land ownership diversity in the Big Sky Region.

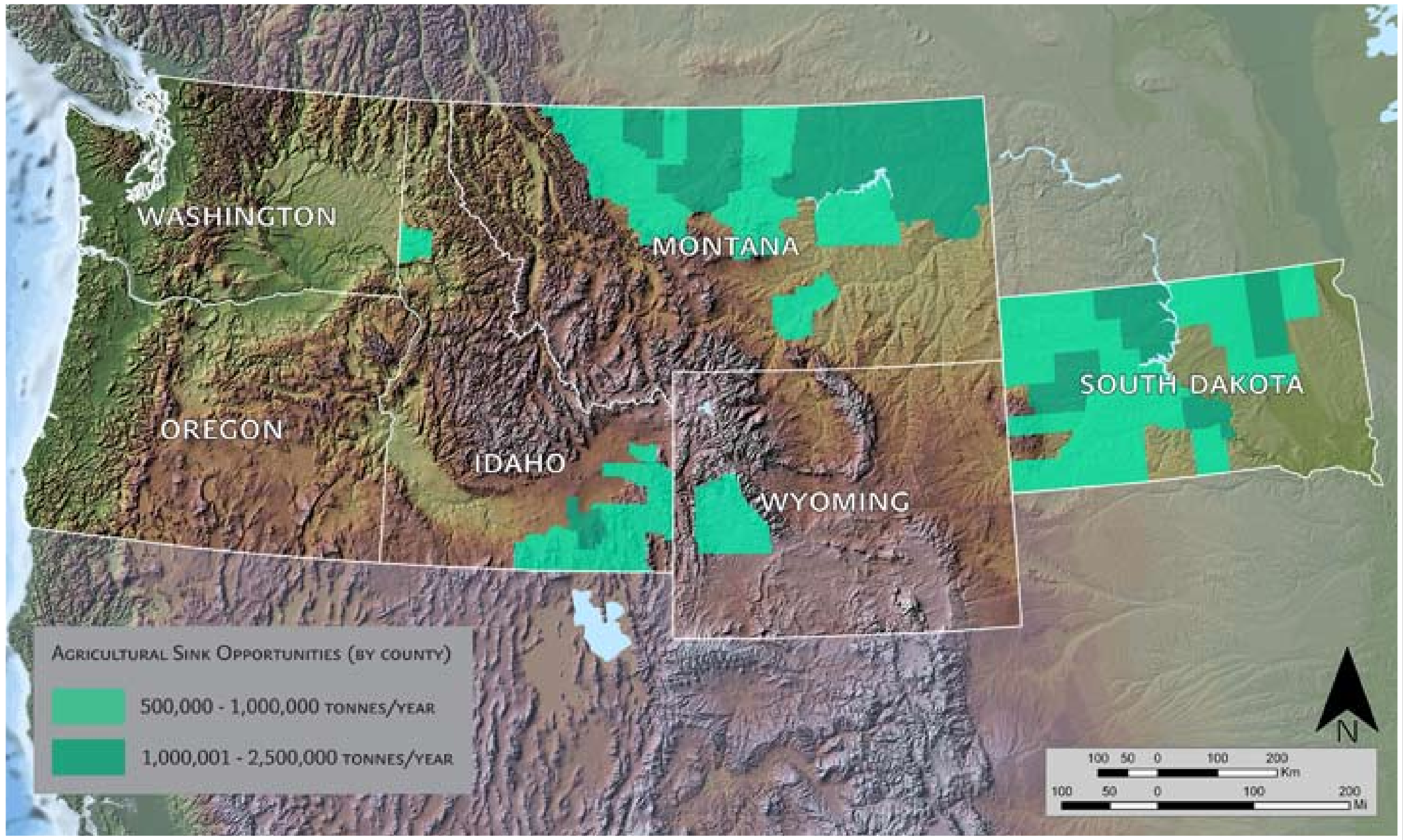
BSCSP Terrestrial Opportunities

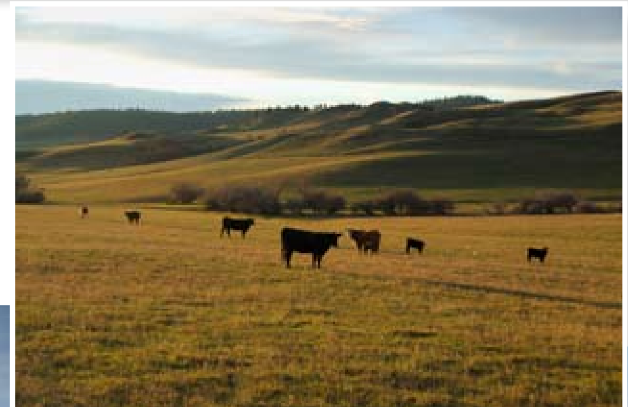
The BSCSP Region has extensive land area that provides tremendous potential for greenhouse gas offsets through terrestrial carbon sequestration in forests, rangelands, and agricultural croplands. Based on current land use practices, the Region can potentially sequester 6.7 million metric tons (7.4 million tons) of CO_2 per year in agricultural lands. BSCSP has developed a market-based approach to carbon storage and verification protocols that includes: (1) establishing terrestrial pilots in cropland, forestland, and rangeland; (2) designing carbon portfolios in conjunction with industry, tribal members, and landowners; and (3) conducting a remote sensing study of management practices and adoption trends in north-central Montana.

The BSCSP is working directly with landowners to provide guidance on land-management practices that maximize carbon storage and to develop initial portfolios. The potential development and design of carbon markets is being explored by two parallel efforts: (1) the development of carbon market portfolios with individual landowners and land managers led by the National Carbon Offset Coalition (NCOC), and (2) the use of a computer simulation model to assess terrestrial carbon storage potential and carbon market opportunities at a county level led by a team from the South Dakota School of Mines and Technology.

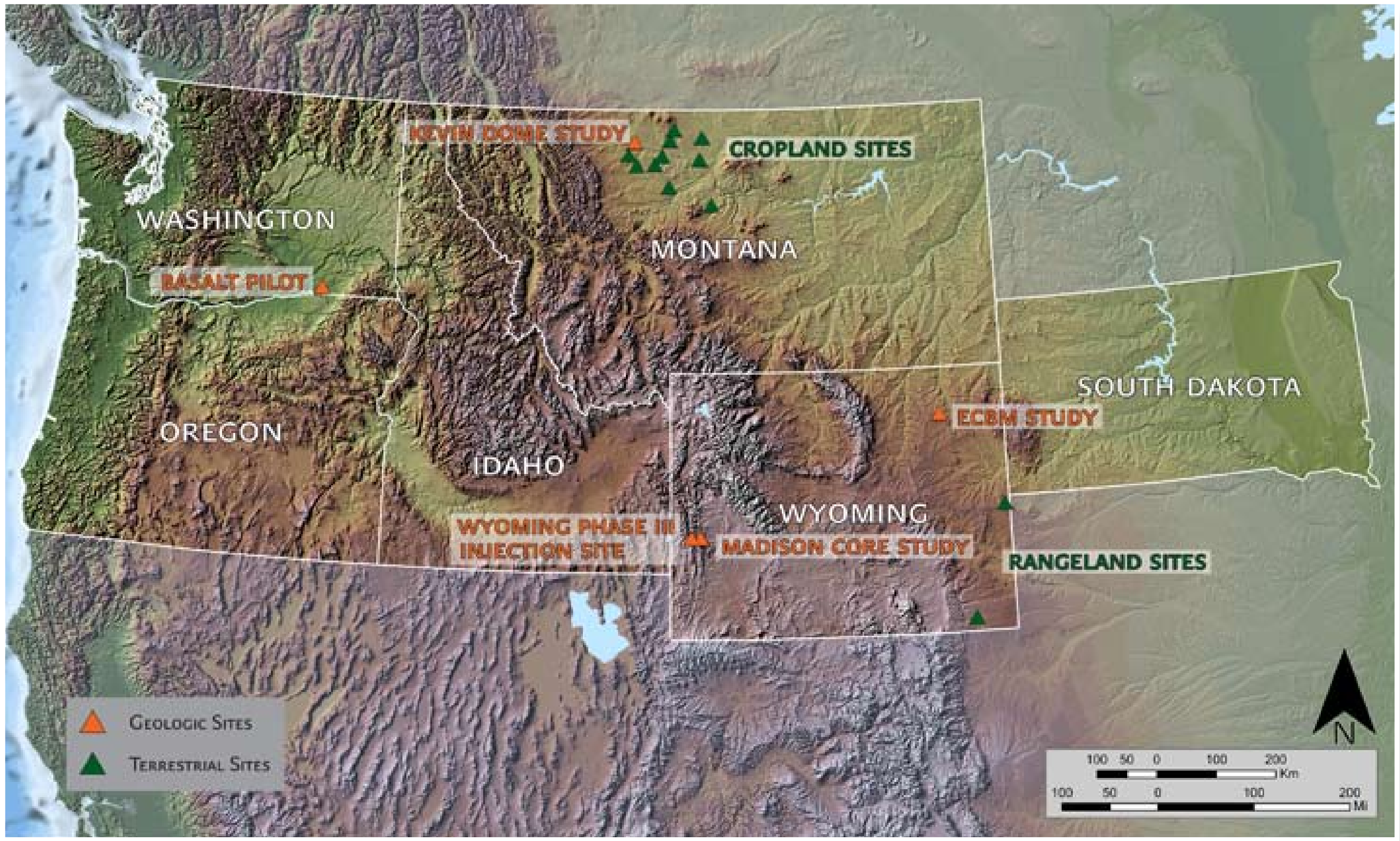
Currently, a total of 5,700 metric tons (6,300 tons) of CO_2 on tribal lands have been traded from the Nez Perce account for reforestation projects. Continued collaboration with the Fort Peck Tribe on a range offset project for 1,480 km^2 (366,000 acres) and the Northern Cheyenne tribe on a proposed forestry project for approximately 61 km^2 (15,000 acres) further utilizes tribal lands for CO_2 activities in the BSCSP Region.

A total of 73,402 metric tons (80,900 tons) of CO_2 was traded this quarter for 66 Montana landowners on 447 km^2 (110,379 acres) of no-till and grass plantings. The second pool of no-till and grass planting projects is now being organized with landowners in Montana, Colorado, and Nebraska. The first New Mexico Range pool with 8 landowners on 1,165 km^2 (287,979 acres) has contracted for 202,245 metric tons (223,000 tons) of CO_2 and is scheduled to undergo third-party verification in May. A second range pool of 23 landowners from Montana, Wyoming, Colorado and Texas are now being organized and contracted. This pool is scheduled to undergo third-party verification in June. To date NCOC has also signed up 13 affiliate organizations (organizations agreeing to assist landowners in completing project applications).

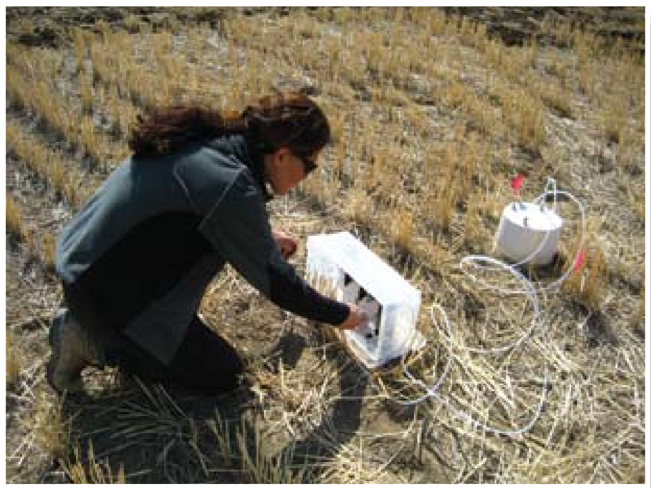




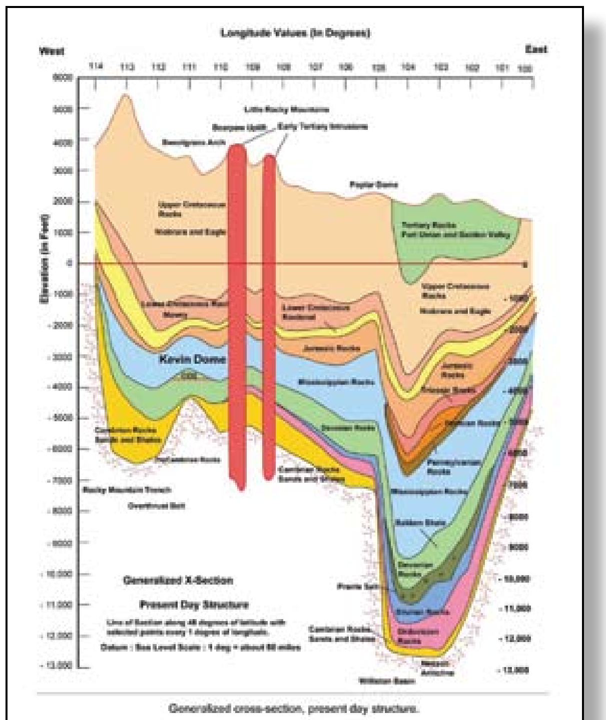
BSCSP is assessing land management practices to best facilitate terrestrial sequestration.



The map shows the locations of the geologic and terrestrial pilots and studies that the BSCSP is undertaking in the Validation and Development Phases. The paragraphs below provide brief descriptions of the projects.



Field tests are conducted on cropland to measure naturally occurring CO_2 fluctuations.



BSCSP Pilot Tests

Validation Phase Geologic Tests and Characterization Efforts

Madison Core Study, SW Wyoming—The objective of this study is to perform a detailed core and structural analysis of the Madison Formation in the Moxa Arch to help understand changes in rock properties resulting from CO_2 exposure and to determine the potential leakage pathways and the best MVA technologies.

Enhanced Coal Bed Methane Recovery (ECBM) and CO_2 Sequestration, East Wyoming—A reservoir simulation in a Powder River Basin coalfield in Wyoming found that there can be significant recovery of coal-bed methane with injection of pure CO_2 versus injection of flue gas. The results indicate that pure CO_2 does not mix with methane and eliminates the need for gas separation facilities.

Montana Kevin Dome Characterization Study, Northern Montana—The purpose of this study is to understand the reservoir and trapping characteristics of Kevin Dome, a geologic structure that contains naturally occurring CO_2.

Basalt Hosted Saline Formation Characterization and Pilot Test, SE Washington—A small scale CO_2 injection 900–2700 metric tons (1000–3000 tons) into the Columbia River flood basalts will confirm feasibility of safe, permanent storage of CO_2 by addressing technical issues associated with the transport and injection of supercritical CO_2 in deep flood basalt formations.

Development Phase Geologic Test

Nugget Sandstone Large Volume Injection Test, SW Wyoming—With the cooperation of industry partners, Cimarex and Schlumberger, the BSCSP plans to inject up to 2.7 million metric tons (3 million tons) of CO_2 from a Cimarex Energy gas processing plant into the Nugget Sandstone on the Riley Ridge Unit on the LaBarge Platform in southwest Wyoming. The injection into the Nugget saline formation will be at depths of 3,350 m (11,000 ft), which is substantially deeper than most pilot tests to date. The Nugget sandstone represents a key opportunity for sequestration in the region because it can potentially store more than 100 years of current emissions from power plants in Wyoming and is similar to other sequestration target saline formations in the region. Additionally, the area has access to the state-wide CO_2 pipeline infrastructure, making it the basis for an economic evaluation at commercial scale.

Placement of survey equipment at a proposed basalt field site.

Validation Phase Terrestrial Tests

Carbon Market Explorations—Efforts include developing initial portfolios with landowners and working with potential buyers and other partners to establish prices, contract terms, MVA procedures and responsibilities of participants.

Cropland Field Validation Test—The objective of this test is to quantify and determine cropland management practices that optimize carbon sequestration and develop MVA protocols to evaluate carbon sequestration for enrolled farms.

Rangeland Sequestration Potential Assessment—Field studies are being conducted at three sites in the northern mixed-grass prairie of Wyoming. The purpose of these studies is to determine the effect of grazing intensity (none, light, heavy) and seasonality of grazing (early-season, late-season) on rangelands.

BSCSP Region Commercialization Opportunities

Early Opportunities for Commercialization in the BSCSP Region

The BSCSP Region has several ongoing and proposed projects, existing infrastructure, and regional initiatives that are helping move CCS forward in the Region.

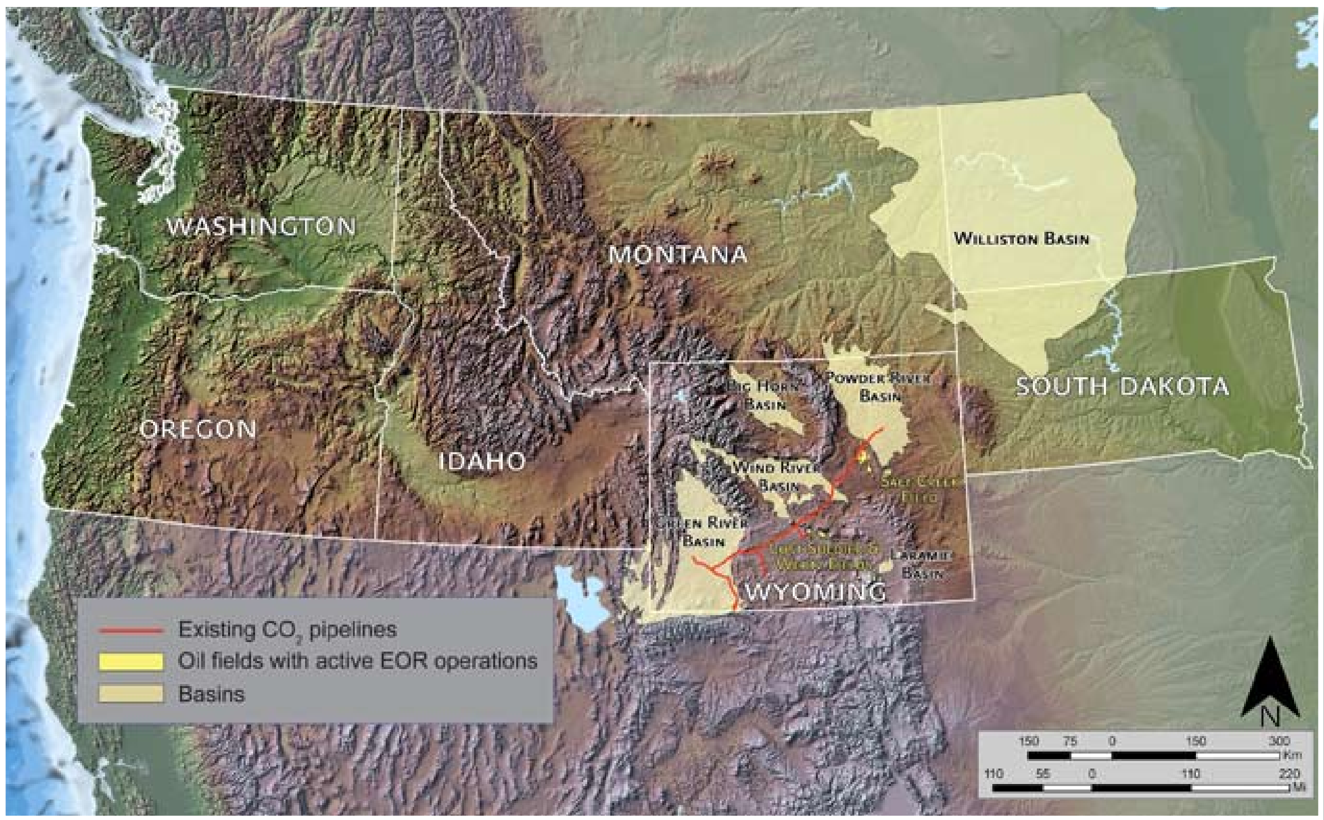
Currently, there are several power plants being proposed in the Region with CCS. In northern Montana, a 250 MW plant with fluidized bed combustion technology is being proposed with capture that would meet California's AB 32 emission performance standards. Also in Montana, research is being conducted to evaluate Kevin Dome as a potential CO_2 sequestration site for proposed plants in the Region. In Washington, a 900 MW IGCC plant is being proposed with 65 percent CO_2 capture and permanent sequestration with injection in basalt flow targets.

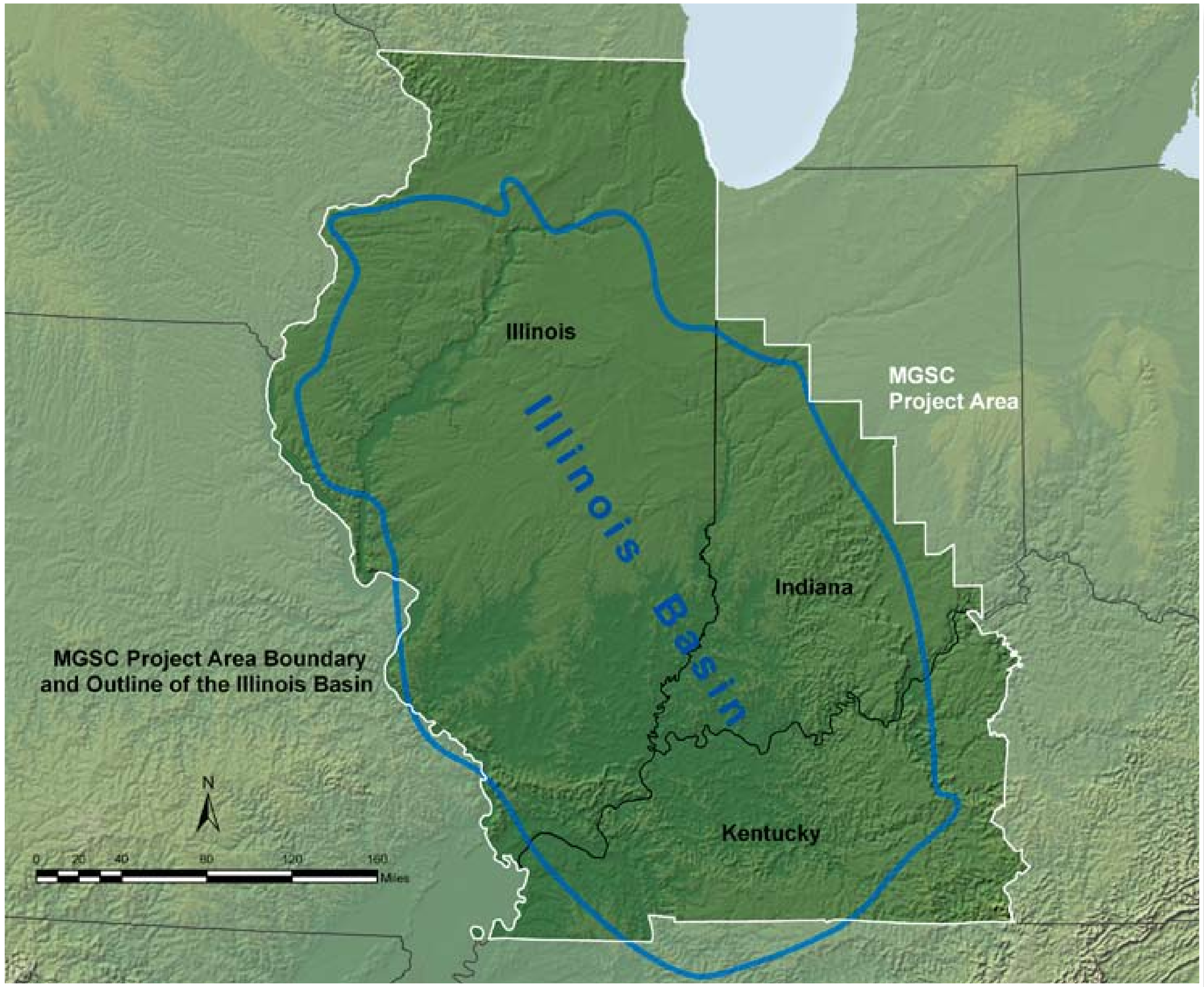
EOR and Infrastructure

Active EOR operations within the BSCSP Region include projects in the GRB and PRB. The Exxon-Anadarko CO_2 pipeline system delivers CO_2 from a gas processing plant to the Salt Creek, Lost Soldier, and Wertz oil fields for EOR. Wyoming is continuing to develop its CO_2 pipeline infrastructure to make CO_2 transportation more efficient and to access other depleted oil reservoirs in the Big Horn, Williston, Wind River, and Laramie Basins. The Devon CO_2 pipeline will extend the existing pipeline from Bairoil to Beaver Creek oil fields and should be operational in 2008. Construction of a CO_2 pipeline to Glenrock, WY has also been proposed.

Regional Initiatives

All of the states in the BSCSP Region have committed to participate in regional greenhouse gas initiatives. Washington, Oregon, Montana, Wyoming, and Idaho are participating as partners or observers with the Western Climate Initiative (WCI). The WCI's overall goal is to reduce regional greenhouse gas emissions. South Dakota is an observer with the Midwest Greenhouse Gas Accord, an agreement to establish regional initiatives to increase energy security, promote renewable energy, and reduce greenhouse gas emissions. Additionally, states within the BSCSP have passed bills to incentivize CCS, to determine pore space ownership, and to set performance standards and establish oversight and authority of CCS operations. Several states have also formed legislative committees to focus on implementing a regulatory framework and drafting new bills.





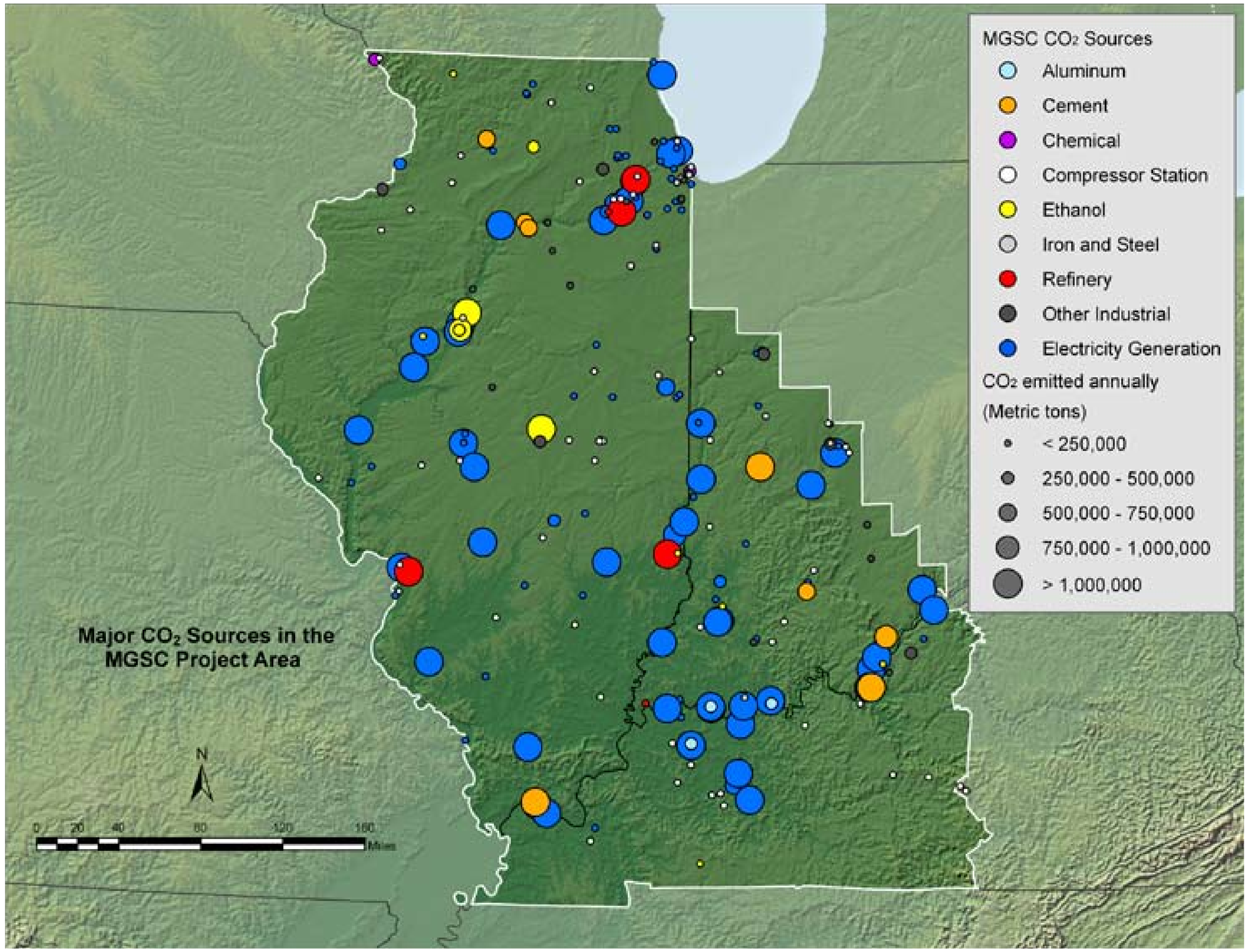
Midwest Geological Sequestration Consortium

The Midwest Geological Sequestration Consortium (MGSC) is comprised of the geological surveys of Illinois, Indiana, and Kentucky, joined by private corporations, professional business associations, the Interstate Oil and Gas Compact Commission, two Illinois state agencies, and university researchers to assess carbon capture, transportation, and geologic storage processes and their costs and viability in the three-state Illinois Basin region. The Illinois State Geological Survey is the Lead Technical Contractor for the Consortium. The MGSC Partnership area covers all of Illinois, southwest Indiana, and western Kentucky.

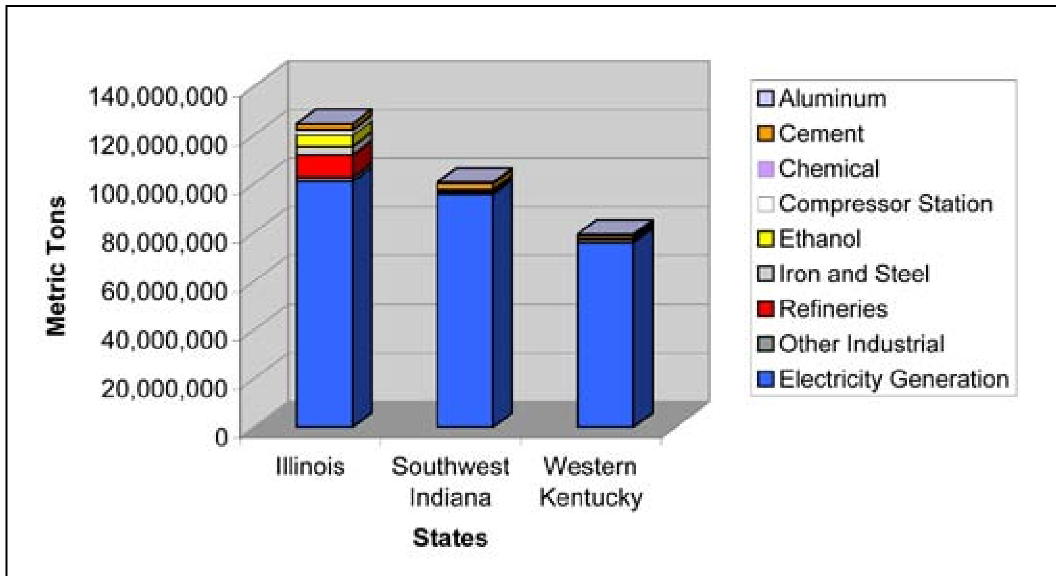
To reduce atmospheric release of CO_2 from fossil fuel combustion and thereby reduce the potential for adverse climate change, the MGSC is investigating options for geologic CO_2 sequestration in the 155,400-km^2 (60,000-mi^2), oval-shaped, geologic feature known as the Illinois Basin. Within the Basin are deep, uneconomic coal resources, numerous mature oil fields, and deep saline formations with the potential to store CO_2. MGSC's objective is to determine the technical and economic feasibility of using these geologic formations for long-term storage.

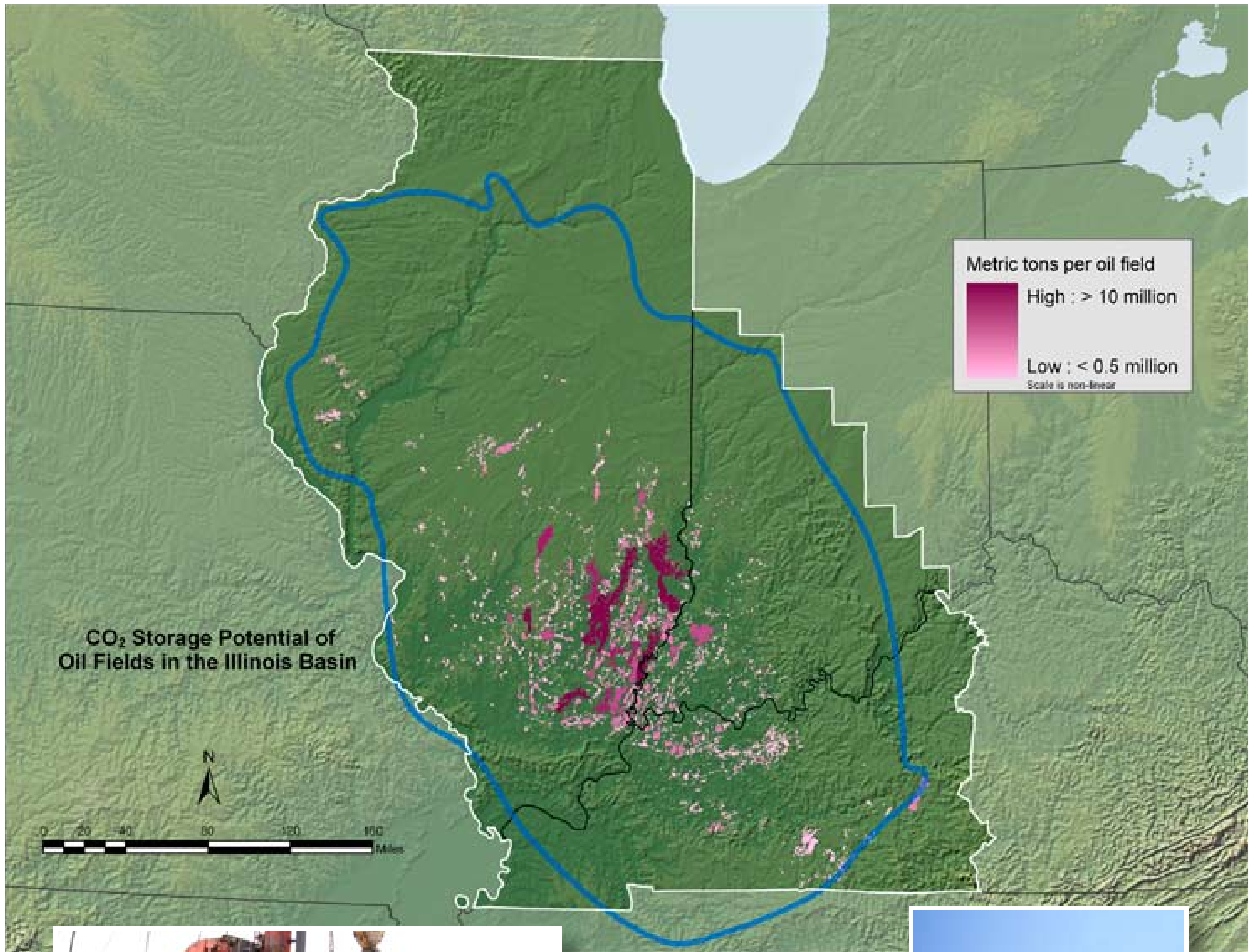
MGSC Stationary Anthropogenic CO_2 Sources

The Illinois Basin Region has annual emissions exceeding 300 million metric tons (335 million tons) of CO_2 (> 83 million metric tons [91 million tons] carbon equivalent) primarily from over 250 stationary sources. Coal-fired, electric generation facilities are the dominant stationary source, some of which burn almost 4.5 million metric tons (5 million tons) of coal per year. The distribution of emissions from these plants is highly skewed. The 4 largest plants, in megawatt capacity, emit about 22 percent of total CO_2 emissions; the 13 largest plants emit > 50 percent of total CO_2 emissions; and the 30 largest plants emit > 80 percent of total CO_2 emissions. The Illinois Basin contributes about 11.4 percent of the total CO_2 emissions from electric power generation plants in the United States. Coal is the dominant fossil fuel for electric power plants and contributes 98 percent of the Illinois Basin CO_2 emissions from stationary sources. CO_2 emissions from manufacturing industries in the Illinois Basin vary from industry to industry.



Illinois Basin (MGSC) CO_2 Emissions by State and CO_2 Source Type				
Source Type	Illinois Basin Annual CO_2 Emissions (million metric tons)			
	Illinois	Southwest Indiana	Western Kentucky	Total
Aluminum	0	0.5	0.7	1.2
Cement	2.5	2.6	1.1	6.2
Chemical	0.7	0	0	0.7
Compressor Station	1.4	0.3	0.3	2.0
Ethanol	4.8	0.2	0.2	5.2
Iron and Steel	3.5	0.1	0.1	3.7
Refineries	9.1	0.2	0	9.4
Other Industrial	1.7	0.9	1.1	3.6
Electricity Generation	101.0	95.7	75.8	272.5
TOTAL	124.6	100.5	79.2	304.4





Oil wells in the Illinois Basin.

MGSC: Illinois Basin Oil and Gas Formations

Because of the established effectiveness of CO_2 EOR, oil reservoirs offer the most potential for economic offset to the costs associated with carbon sequestration in the Illinois Basin. To assess this potential, a Basin-wide EOR estimate was made based on new understanding of the original oil-in-place (OOIP) in the Basin, the CO_2 stored volume, the assessed EOR resource, the geographic distribution of EOR potential, and the type of recovery mechanism (miscible vs. immiscible). The oil resource target for EOR is 137 to 207 million m^3 (860 to 1,300 million barrels [bbl]) recoverable oil with a consequently sequestered volume of 140 to 440 million metric tons (154 to 485 million tons) of CO_2.

With cumulative oil production for the Basin of about 0.67 billion m^3 (4.2 billion bbls), nearly 1.5 billion m^3 (10 billion bbls) of resources remain, primarily as unrecovered oil resources in known fields. To assess the recovery potential of a part of this resource and the concurrent stored CO_2 volumes, reservoir modeling and compositional reservoir simulation were carried out. Sections of nine fields were used to create generic geologic models for the most prolific oil-bearing reservoirs in the Basin, the Aux Vases, the Cypress Sandstones, and the St. Genevieve Limestone. These models incorporated data from > 1,000 total wells, 120 wells with core, > 2,000 core sample points, 12,000 field acres, and 20 flow zones. Structure and isopach maps were developed deterministically from well logs, whereas porosity and permeability distributions were developed geostatistically from core analysis data for the reservoir simulator. Processes simulated were miscible and immiscible flooding, based on reservoir pressure and temperature, and both continuous and water-alternating-gas CO_2 injection.

State	Potential CO_2 Storage Resource (million metric tons)	Estimated EOR* (million barrels)
IL	106 to 358	632 to 979
IN	20 to 47	124 to 162
KY	14 to 35	104 to 138
TOTAL	140 to 440 million metric tons	860 million to 1.3 billion barrels

* The EOR volume was estimated based on a series of oil recovery factors for specific geologic units and miscibility types that were applied to the OOIP as assessed per oil field.

MGSC: Illinois Basin Unmineable Coal Seams

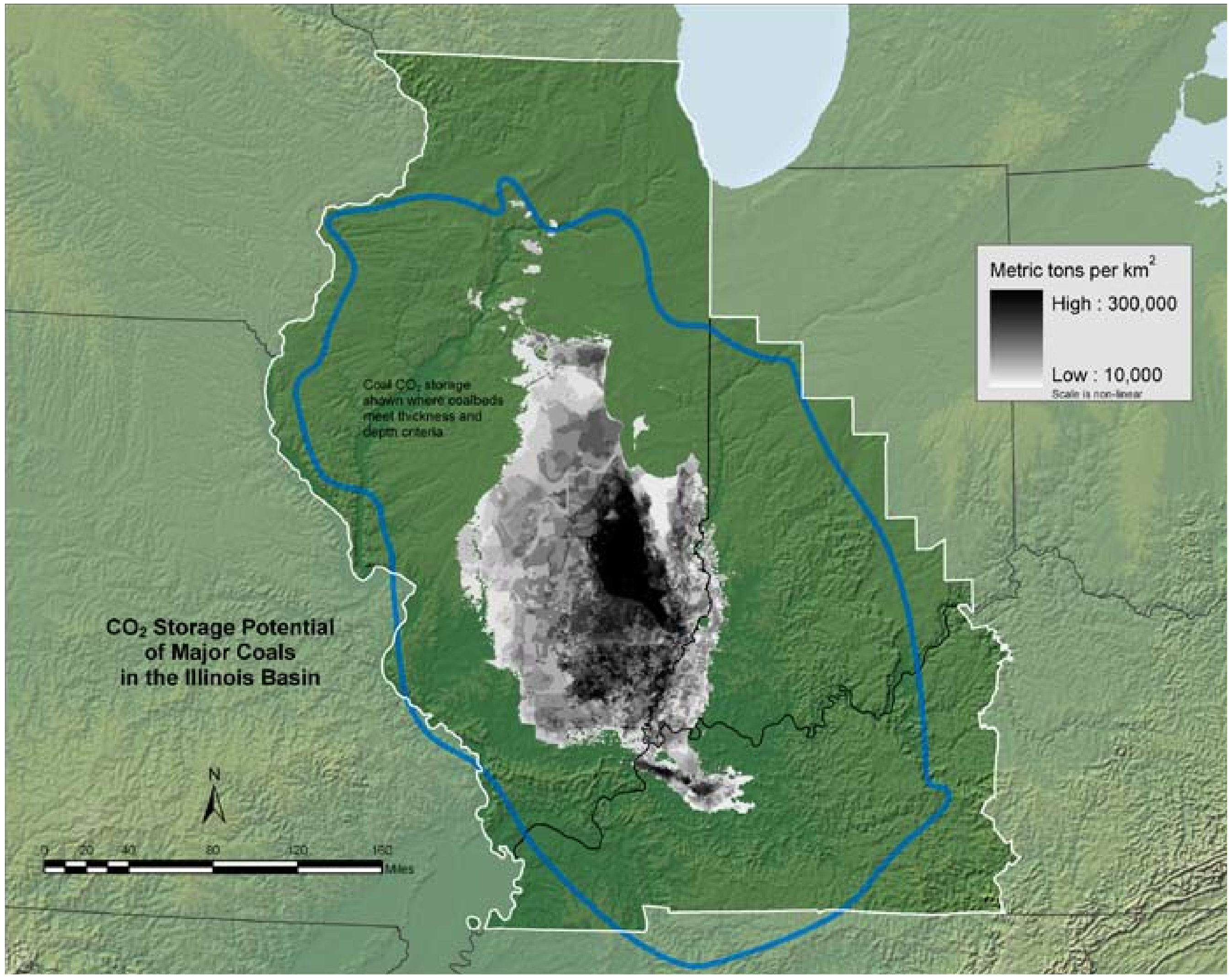
The Illinois Basin includes substantial coal resources, totaling 258 billion remaining metric tons (284 billion tons). Extraction techniques range from surface mining to room-and-pillar and longwall subsurface methods, with most mining occurring around the margins of the Basin. Most of the Basin's remaining coal resources are moderate to high in sulfur content. Consequently, market share has been lost to low-sulfur, western coal from the PRB, and Illinois coal production has declined by half since 1990. The opportunity to sequester CO_2 in coal seams currently considered to be unmineable is based on both technical and economic considerations and could be supported by production of coalbed methane displaced from these coals.

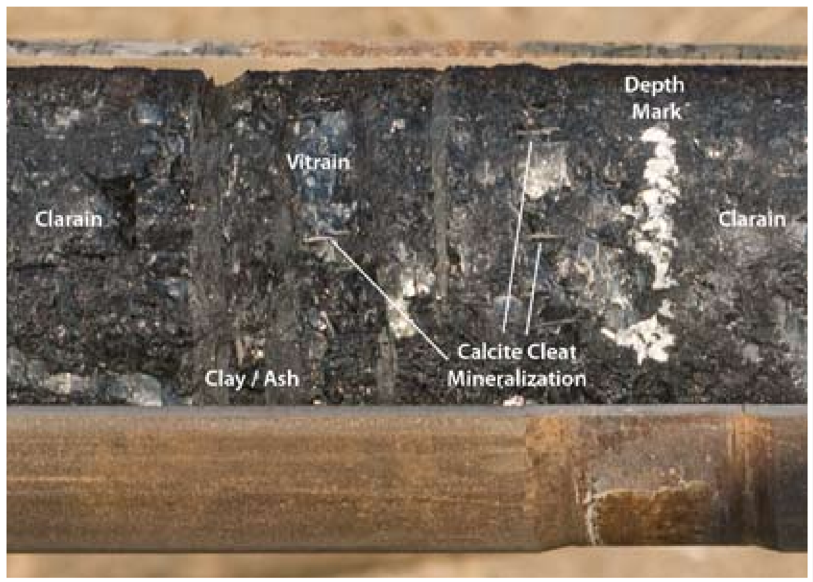
With respect to defining unmineable coal, no consideration is given to coals at depths < 152 m (< 500 ft). From 152 to 305 m (500 to 1,000 ft) in depth, coals from 0.48 to 1.1 m (1.5 to 3.5 ft) in thickness are considered sequestration targets. A seam < 1.1 m (< 3.5 ft) in thickness is currently not underground mineable with existing equipment. It would be costly to develop new equipment compared to mining seams of greater thickness, which remain as an abundant part of the resource base. For depths greater than 305 m (1,000 ft), all seams > 1.1 m (> 1.5 ft) in thickness are considered a sequestration target.

Key characteristics of seven coals were mapped throughout the Illinois Basin, including thickness, depth, elevation, moisture content, ash content, heating value, temperature, and expected reservoir pressure. Most data were available for the Herrin and Springfield coals, the major coal seams in the Basin. Gas contents for Illinois Basin coals are in the range of 3.12 to 4.68 m^3/metric ton (100 to 150 standard cubic feet [scf]/ton) for the better samples. CO_2 adsorption capacity can range from 14.1 to 21.9 m^3/metric ton (450 to 700 scf/ton) at 2,068 kPa (300 psi).

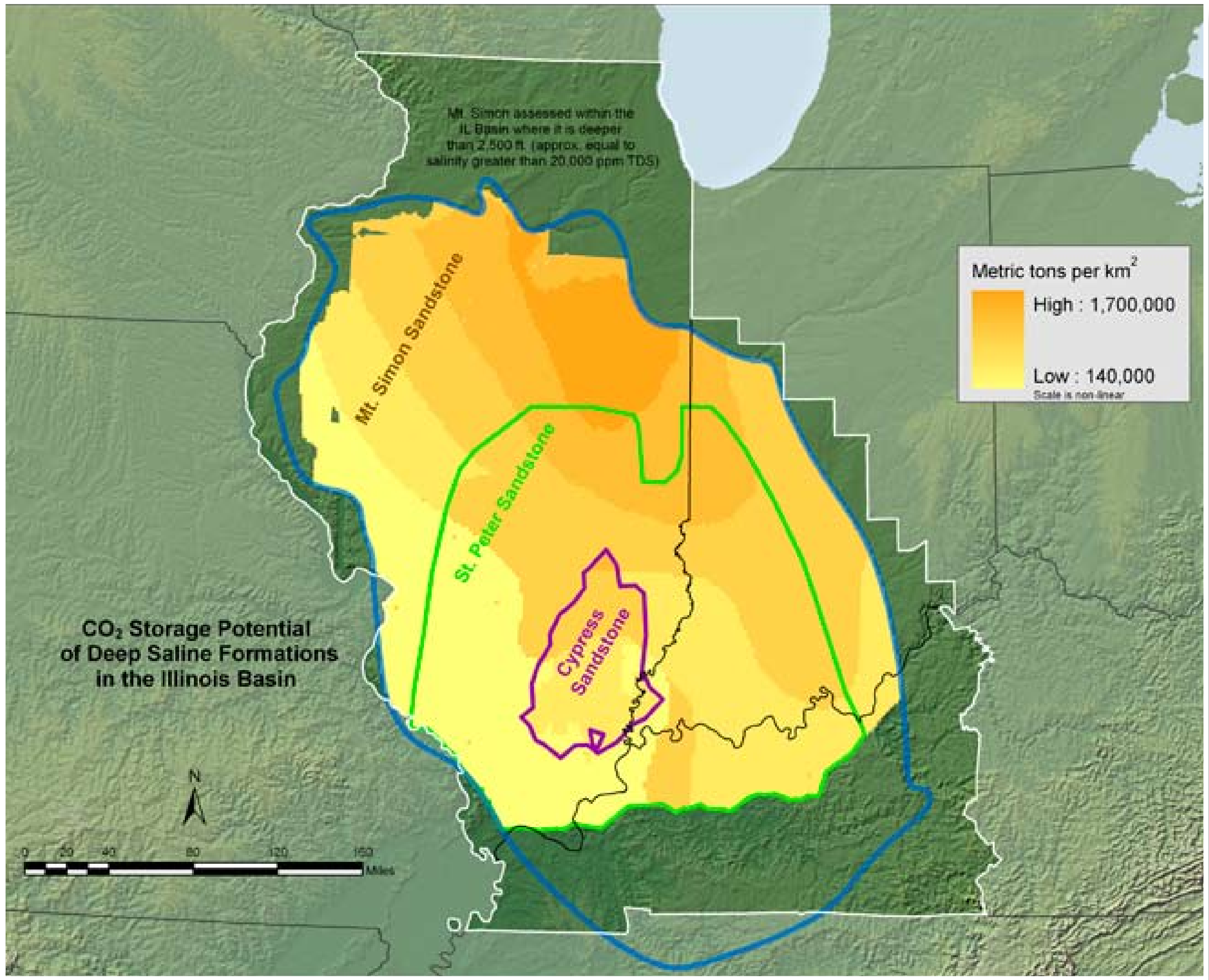
State	Potential CO_2 Storage Resource (million metric tons)	Estimated ECBM* (billion scf)
Illinois	1,500 to 2,140	2,700 to 9,800
Indiana	88 to 126	150 to 600
Kentucky	70 to 100	130 to 470
TOTAL	1.7 to 2.4 billion metric tons	3.0 to 10.9 trillion scf

* ECBM was estimated based on a methane recovery factor that was applied to the original gas-in-place volume per coal seam for unmineable coal areas as described above.





Banded horizons in Springfield Coal core. Core was drilled vertical and is shown rotated 90 degrees.



MGSC: Illinois Basin Deep Saline Formations

Three saline formations in the Illinois Basin were studied for CO_2 storage potential: the Mississippian Cypress Sandstone, the Ordovician St. Peter Sandstone, and the Cambrian Mt. Simon Sandstone.

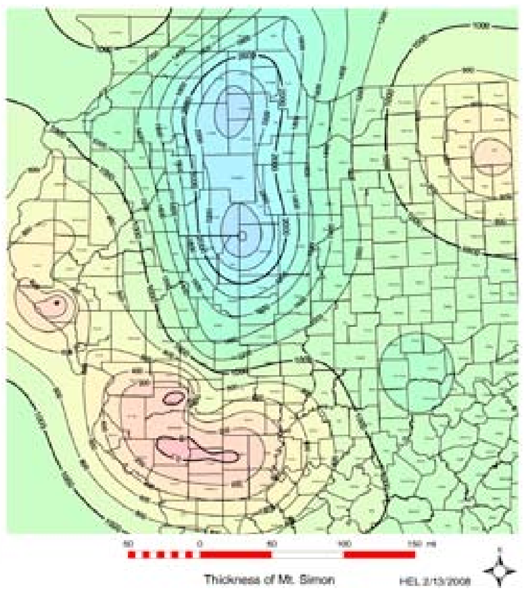
The Cypress Sandstone is the most widespread and prolific petroleum-bearing sandstone in the Illinois Basin, with production exceeding one billion barrels of oil to date. Areas with thick Cypress tend to have a large water-bearing zone that may be considered a saline storage target. The porous and permeable sandstone can reach a thickness of 61 m (200 ft), although it is generally less than 30 m (100 ft) thick and displays considerable variation in thickness and lateral extent. It is the shallowest of the three saline formations assessed, and is found at depths up to approximately 910 m (3,000 ft) in parts of the Illinois Basin. Shale beds and a laterally continuous carbonate, the Beech Creek (Barlow) Limestone, form the overlying seal for the Cypress Sandstone.

The St. Peter Sandstone is a widespread, porous, and permeable quartz sandstone that is generally fine-grained with good lateral continuity. Seals above the St. Peter Sandstone include several hundred feet of dense limestone and dolostone overlain by 45.7 to 76.2 m (150 to 250 ft) of Maquoketa Shale.

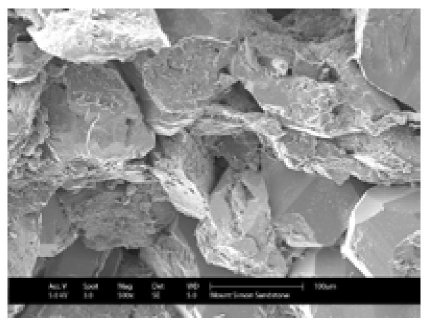
The Mt. Simon Sandstone is commonly used for natural gas storage in the Illinois Basin and has fair to good permeability and porosity. Overlying strata contain impermeable limestone, dolomite, and shale intervals. The depth of the Mt. Simon Sandstone ranges from approximately 610 to 4,267 m (approx. 2,000 to 14,000 ft) below the surface; in the southern half of the Basin the reservoir is brine-filled, and no oil or natural gas resources have been discovered in this unit. At its greatest thickness in the Illinois Basin, the Mt. Simon Sandstone is over 793 m (2,600 ft) thick. The Mt. Simon does not outcrop in Illinois, but correlative units are exposed in southern Wisconsin, southeastern Minnesota, and Missouri. The Mt. Simon exists in the subsurface throughout much of Indiana, Iowa, Michigan, and Ohio. In the southern region of the Basin, the potential CO_2 reservoir facies are either very deep or are absent in the paleotopography.

Reservoir	Potential CO_2 Storage Resource (billion metric tons)
Cypress Sandstone	0.4 to 1.7
St. Peter Sandstone	1.6 to 6.4
Mt. Simon Sandstone	27 to 109
TOTAL	29 to 117 billion metric tons

State	Potential CO_2 Storage Resource (billion metric tons)
Illinois	20 to 79
Indiana	7.9 to 32
Kentucky	1.5 to 6.3
TOTAL	29 to 117 billion metric tons



Regional thickness of the Mt. Simon sandstone.

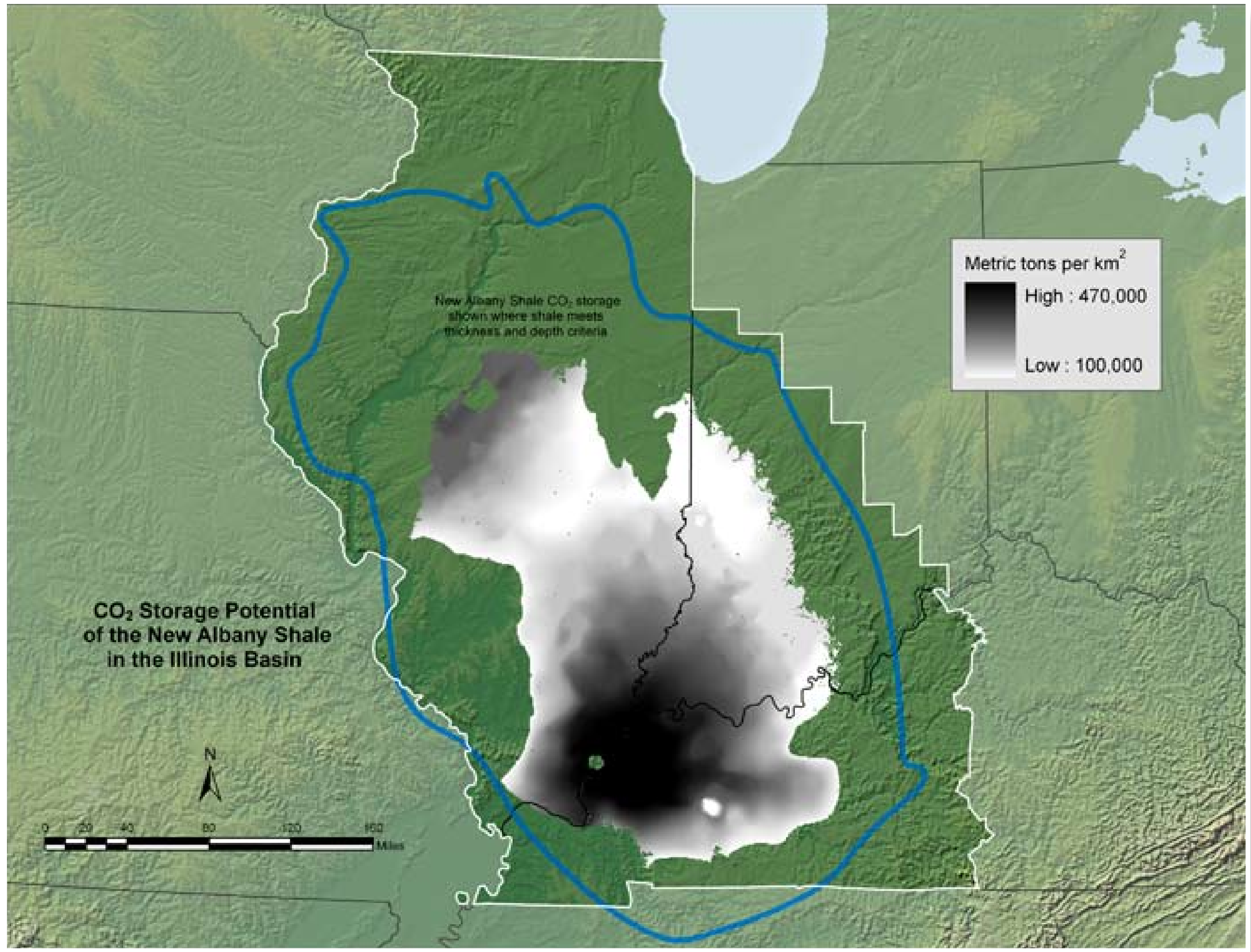


Photomicrograph of the Mt. Simon sandstone, 500X.

Depths less than 762 m (2,500 ft) for the Cypress, St. Peter, and Mt. Simon sandstones were not considered as sequestration targets due to anticipated lower salinity, potentially potable water resources in these areas, and temperatures and pressures insufficient to maintain dense-phase CO_2. However, a CO_2 storage resource is available and should be considered on a site-by-site basis.

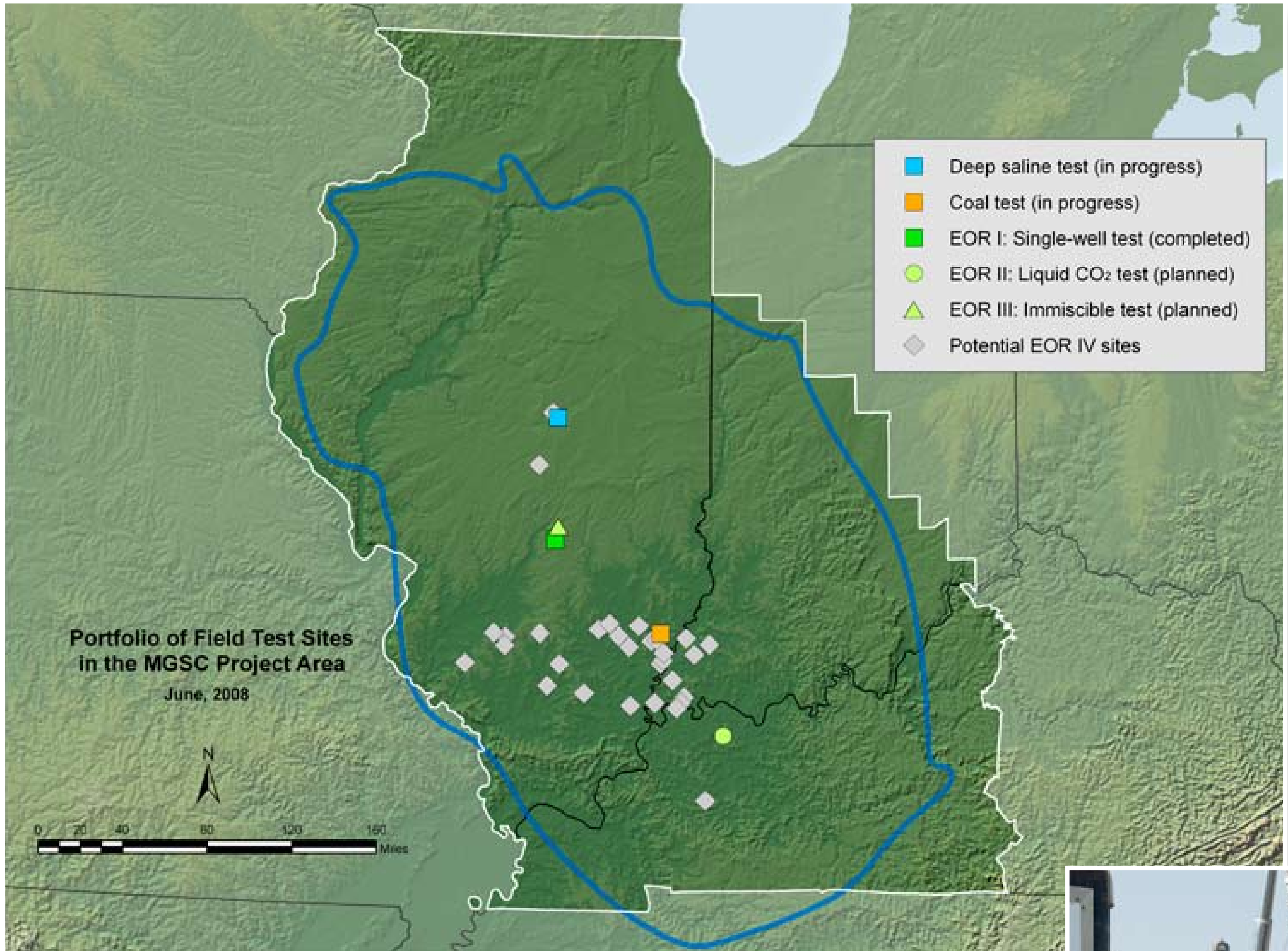
MGSC: Illinois Basin Deep Shales

Organic-rich shales in the Illinois Basin will be assessed from two perspectives. The Devonian New Albany Shale in the Illinois Basin is potentially commercially productive of natural gas in the same way as the stratigraphically equivalent Antrim Shale in the Michigan Basin, a play that currently supports over 7,600 producing wells, and the Devonian Ohio and related shales of the Appalachian Basin support over 10,000 wells in eastern Kentucky. New Albany reservoirs exist in Indiana and Kentucky, and samples are currently being tested for their CO_2 adsorption capacity. Organic carbon content of the shale is directly related to the CO_2 adsorption capacity. Injection of CO_2 into the organic shales may result in adsorption of CO_2 and possibly associated enhanced production of methane gas, similar to coalbeds. The New Albany Shale is the primary seal for Silurian and Devonian oil and gas reservoirs, and it may act as a secondary seal for sequestration in deeper Paleozoic reservoirs, like the Mt. Simon and St. Peter Sandstones. Initial volumetric estimates indicate that up to 15 billion metric tons of CO_2 could be sequestered in the organic-rich shales of the Illinois Basin. This estimate is being refined by considering the distribution and quantity of organic matter in the shale, injectivity, and displacement efficiencies during the Validation Phase.



Regional shale outcrop.

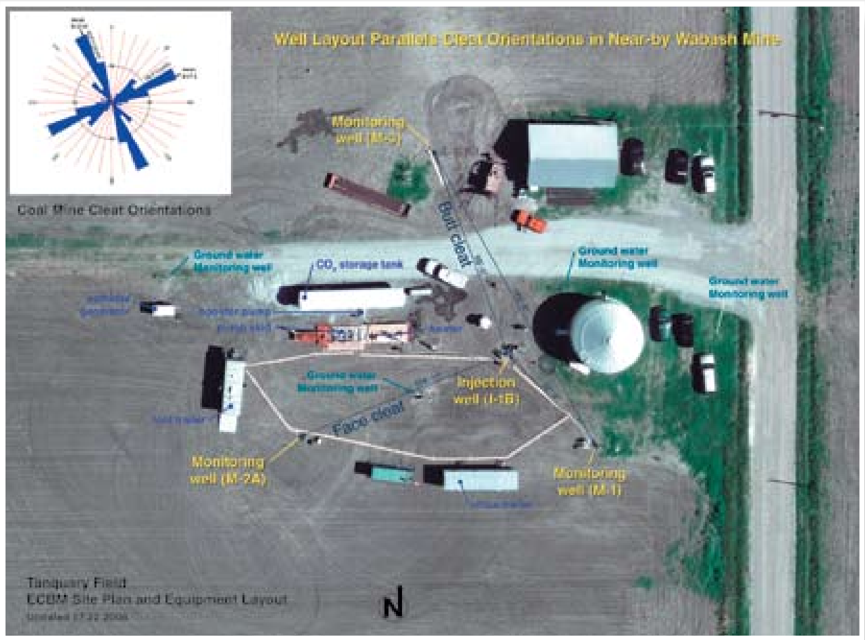
Regional shale outcrop.



MGSC Validation Phase Field Tests

The MGSC, along with its industry partners, is conducting a series of six field validation tests in the Illinois Basin to assess the potential for CO_2 storage in oil reservoirs, coal seams, and deep, saline water-bearing formations. Added-value benefits for CO_2 storage in oil reservoirs and coal beds are the potential for EOR and ECBM production, respectively. The planned deep saline "Mt. Simon Sandstone" test has been expanded into the MGSC large-scale demonstration project for the Development Phase. The Mt. Simon Sandstone is expected to have the most storage of all geologic formations.

The MGSC effort focuses on a series of field tests, beginning with a one-well, inject/soak/produce oil reservoir test and culminating with drilling to a deep saline formation and injecting CO_2. Between these end members, an ECBM test and mature oil field tests will involve well conversion(s) and drilling of one or more new injection wells to evaluate pattern flooding. Test sites will incorporate miscible and immiscible flooding and assess Illinois Basin sandstone and carbonate reservoirs to provide both comparison and contrast to the Permian Basin (West Texas) experience, which is dominated by miscible carbonate floods.



Layout of coal test site. Inset shows coal cleat orientation at a nearby mine.

Collecting core at coal test site.

Coalbed Methane

The coalbed methane project was initiated in July 2007. This pilot project includes one injection and three monitoring wells. Two monitoring wells are located 50 and 100 feet in the butt cleat direction on each side of the injection well; the third monitoring well is 100 feet from the injection well in the face cleat direction. Two wells were drilled in July 2007; the remaining two wells were drilled in May 2008, prior to CO_2 injection in the summer of 2008. A multi-well water and CO_2 pressure transient test will be used to better understand CO_2 sequestration in coal.

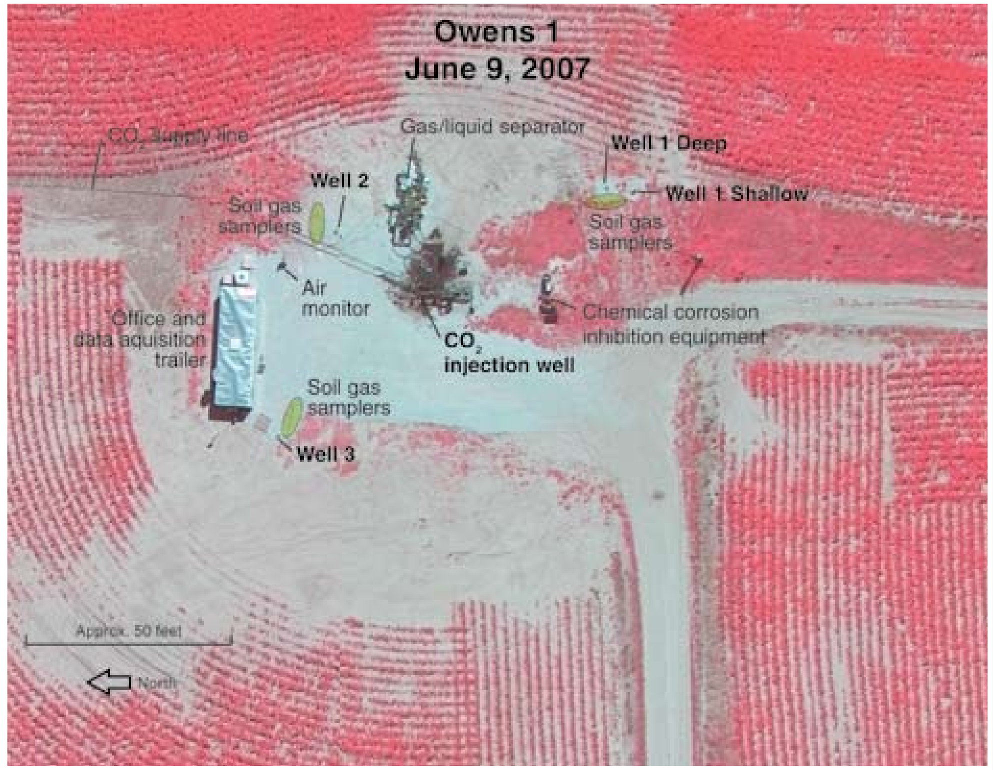
Drill stem test gas sample collection at coal site.

Enhanced Oil Recovery

The first mature oil field test, known as a "Huff 'n Puff," was conducted in March 2007 to evaluate the potential for geologic sequestration of CO_2 in mature Illinois Basin oil reservoirs as part of an EOR program. During the process, CO_2 was injected into a producing well (the "Huff" phase), the well was shut in, allowing CO_2 to mix with the in situ crude oil, and then the well was placed back on production (the "Puff" phase). Site evaluation, evaluation of well data, CO_2 injection, modeling, and MVA efforts are now complete. The primary location is within the Loudon Field in Fayette County, Illinois. Forty-three tons of CO_2 were injected over a five-day period into the Mississippian Cypress Sandstone at a depth of approximately 472 m (1,550 ft).

Accomplishment Highlights:

- Forty-three tons of CO_2 were injected over a five-day period.
- Incremental oil production during the first two months following the soak period was approximately 15 m^3 (95 barrels).
- Results indicate that the Illinois Basin oilfield may have an added-value benefit as a precursor to build and invest in the infrastructure to establish a sequestration industry within the Basin.



Layout of EOR I site in the Loudon oilfield, Fayette County, Illinois.

Casing gas production manifold and portable separator at EOR I site.

CO_2 storage tank, inline header, and pump equipment at EOR I site.

Aerial view of the Illinois Basin – Decatur Project, deep saline test site, Decatur, IL.

MGSC Development Phase Demonstration Project

In view of recent increased attention being placed on global climate change and geologic carbon sequestration, the MGSC, the Archer Daniels Midland Company (ADM), and Schlumberger Carbon Services have joined as partners to expand the originally planned Validation Phase small-scale deep saline formation CO_2 injection into a large-scale deep saline formation CO_2 injection. The newly combined Validation Phase and Development Phase effort will be a large-scale multiyear deployment of geologic sequestration of 1 million metric tons (1.1 million U.S. tons) of CO_2 over 3 years. This large-scale injection project is planned at the ADM plant site in Decatur, Illinois. Injection will be at a depth of 1,830 to 2,390 m (6,000 to 7,000 ft) into the Mt. Simon Sandstone saline formation—one of the most significant potential carbon storage resources in the United States. Two-dimensional seismic data were acquired in October 2007 in preparation for drilling the injection well planned for the fourth quarter of 2008. The Underground Injection Control (UIC) permit application has been completed, a public hearing was held in September, 2008, and the permit is pending final approval from the Illinois EPA. The well location was staked and the MVA program initiated in May of 2008. Injection of CO_2 is expected to begin late 2009.

View of deep saline test site (pre-drilling).

Setting up the Eddy Covariance tower at the Illinois Basin – Decatur site.

MGSC Commercialization Opportunities

The states within the Illinois Basin region are actively considering initiatives that would facilitate deployment of geologic sequestration. The tri-state area is engaged in promoting clean coal technology research and commercialization studies. The Region had two of the semi-final FutureGen sites. Mattoon, Illinois was ultimately selected as the preferred national site by the FutureGen Industrial Alliance. Commercial opportunities for sequestration and coal gasification in concert continue to be considered. CO_2 EOR is currently not active in the Region. The State of Illinois is funding a CO_2 pipeline feasibility study slated to begin in late 2008. In addition to the pipeline study, private sector development of a pipeline to transport CO_2 from the Illinois Basin to the Gulf Coast is under consideration. The MGSC and partners continue to engage in sequestration research and in supplying information to interested commercial parties.

Progress continues on the construction of Duke Energy's integrated gasification combined cycle generation facility at Edwardsport, Indiana. This commercial scale (632 MW) facility will use carbon capture and sequestration technologies to reduce the emission of some of the ~4.5 million metric tons (~5 million tons) of CO_2 to be produced annually. CO_2 will therefore be available for enhanced recovery operations in the Region including potential enhanced gas recovery from the New Albany Shale.

The Kentucky State Legislature provided funding support to conduct an immiscible CO_2 EOR project. A consortium is being formed and industry partners identified to conduct a deep saline injection demonstration project in the Illinois Basin portion of the Kentucky Commonwealth. The newly reorganized Kentucky Cabinet for Energy and Environment is continuing a program to assess sites for development of coal-to-liquids, coal gasification, IGCC, and other clean coal technologies with specific consideration for carbon storage and EOR opportunities.

Aerial image of ADM Plant, Decatur, Illinois.

Midwest Regional Carbon Sequestration Partnership

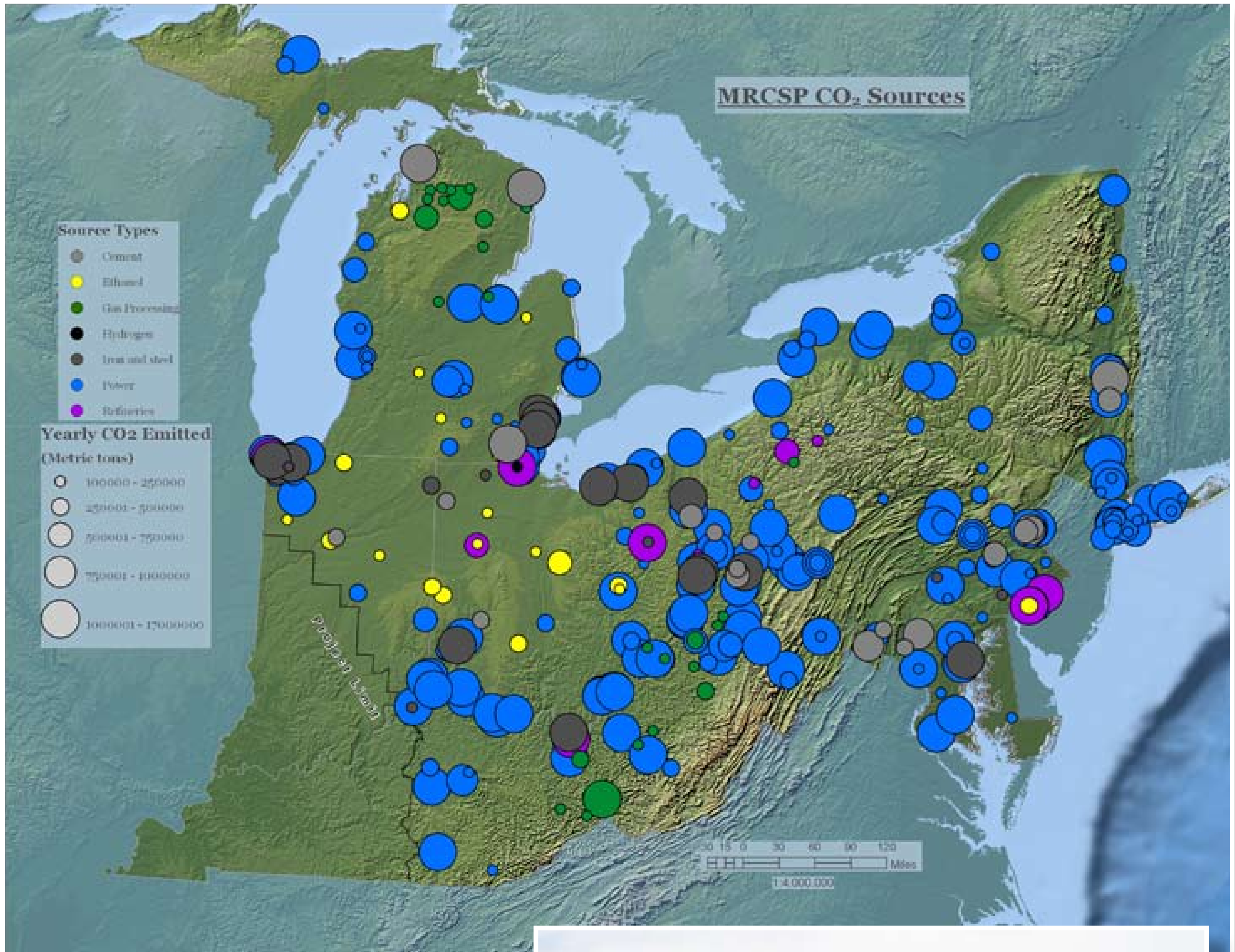
The Midwest Regional Carbon Sequestration Partnership (MRCSP) was formed to assess the technical potential, economic viability, and public acceptability of carbon sequestration within its Region. The MRCSP Region consists of eight neighboring states: Indiana, Kentucky, Maryland, Michigan, New York, Ohio, Pennsylvania, and West Virginia. The Partnership includes over thirty organizations from the research community, energy industry, universities, non-government, and government organizations. The Region has a diverse range of CO_2 sources and many opportunities for geologic and terrestrial sequestration.

Potential locations for geologic sequestration in the MRCSP states include deep rock formations associated with broad sedimentary basins and arches that extend across most of the Region. Research and testing have established many promising geologic units for CO_2 sequestration including deep saline rock formations, depleted oil and gas reservoirs, organic shale layers, and coal beds. Geological surveys from the eight MRCSP states completed an assessment of the potential for geologic sequestration that indicates there is capacity to permanently contain hundreds of years of CO_2 emissions from the Region. Reports, data, and maps generated by the research were integrated into a geographic information system available for use on the MRCSP web site (www.mrcsp.org).

MRCSP Phase I research on terrestrial carbon sequestration focused on five dominant land-use types identified by the research team as offering the best opportunities for the Region. These land use categories included: traditional non-eroded cropland, eroded cropland, marginal lands, mineland areas, and wetlands. The specific objectives of the research were to quantify the carbon storage formation capacity of the major land use components and to identify land use and management options to achieve storage formation capacity such as improved agricultural practices, reforestation, and reclaiming mineland.

CO_2 pipeline from a gas processing plant in Michigan.

MRCSP
MIDWEST REGIONAL
CARBON SEQUESTRATION
PARTNERSHIP



A Snapshot of the MRCSP Region

The MRCSP Region includes

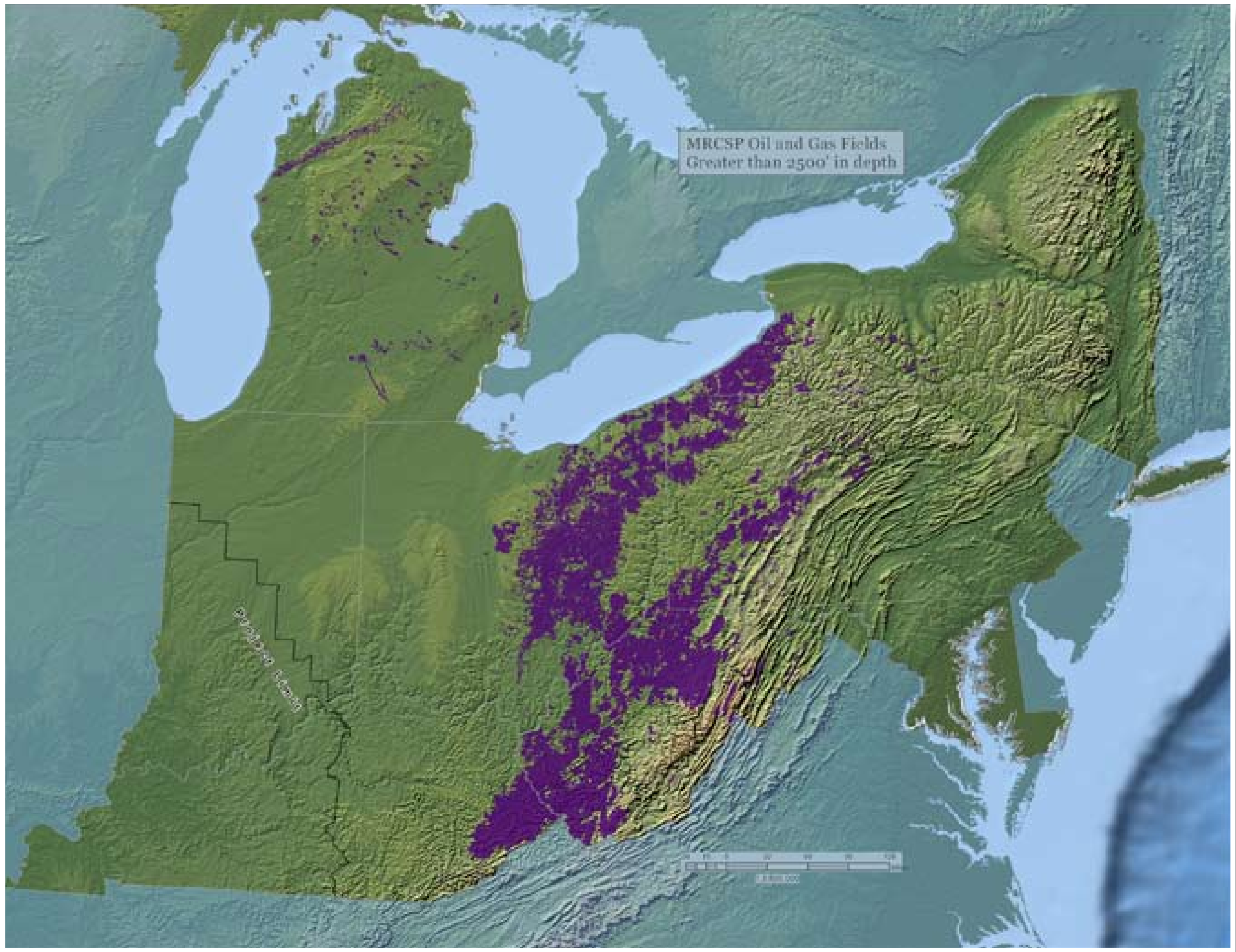
- 8 States: Indiana, Kentucky, Maryland, Michigan, New York, Ohio, Pennsylvania, and West Virginia
- Population: 71.3 million (nearly one quarter of U.S. population)
- Gross Regional Product: $2,672 billion (one quarter U.S. economy)
- 21.5 percent of all electricity generated in the United States
- 77 percent of electricity generated in the Region is generated by coal
- 12 percent of nation's total CO_2 emissions

CO_2 Sources in the MRCSP Region

Due to its large and diverse economy, the MRCSP Region includes a large variety of sources of greenhouse gases. While distributed sources such as agriculture, transportation, and heating account for a large portion of CO_2 emissions in the MRCSP Region, over half of CO_2 emissions are linked to stationary sources. More than 680 million metric tons (750 million tons) of CO_2 are emitted each year from these large, fixed stationary sources including power plants, refineries, cement plants, and iron and steel plants. Emissions are highest along the Ohio River Valley and coastlines where many power plants and industries are located. In the MRCSP Region, 80 percent of CO_2 stationary source emissions are from electrical power plants.

Large CO_2 Stationary Source Emissions (million metric tons CO_2/year)

Category	MRCSP	MRCSP%	Northeastern Indiana	Eastern Kentucky	Maryland	Michigan	New York	Ohio	Pennsylvania	West Virginia
Power	553.8	80.90%	31.7	35.1	32	76.1	49.6	127.3	115.7	86.3
Iron and Steel	70.1	10.20%	26.2	2.4	4.5	12.3	0	17.5	3.3	4
Refineries	20	2.90%	3.9	2.1	0	0.7	0	5.5	7.6	0.1
Cement	14.2	2.10%	0.4	0	1.5	3.5	2	1.4	4.6	0.8
Gas Processing	21.7	3.20%	0	0.6	0	2.9	12.7	0.1	0.5	4.8
Ethanol	4.4	0.60%	1	0	0	0.9	0	2	0.5	0
Total	684.2	100	63.2	40.3	38	96.5	64.3	153.7	132.1	96.1



MRCSP: Oil and Gas Reservoirs

The MRCSP Region has many opportunities for CO_2 sequestration in oil and gas formations. Commercial exploration in the Region began in 1859 with the discovery of oil in a shallow well drilled by "Colonel" Edwin Drake in Titusville, Pennsylvania. Since then, the MRCSP Region has produced over 0.8 billion m^3 (5 billion barrels) of oil and more than 1.4 trillion m^3 (50 trillion ft^3) of natural gas. In addition, the MRCSP Region includes four of the top seven, natural-gas storage states in the nation. Such large volumes of gas storage capacity (both natural and engineered) strongly suggest that CO_2 gas can be successfully managed in subsurface reservoirs within the Region. Finally, there is potential for value-added production of oil and natural gas associated with CO_2 sequestration. The oil and gas fields in the Region are most concentrated in the Appalachian and Michigan sedimentary basins. Research suggests that oil and gas fields have a potential CO_2 storage resource of 8,400 million metric tons (9,300 million tons) of CO_2. Much of this resource is intermixed with deep saline formations. In fact, it may be difficult to differentiate the two in many areas.

Oil and gas reservoirs cover large portions of the Appalachian basin with significant fields in Ohio, western New York, western Pennsylvania, western West Virginia, and eastern Kentucky. Key oil and gas formations in the Appalachian basin include Devonian Shales, "Clinton"/Medina/Tuscarora sandstones, the Oriskany Sandstone, and the Rose Run Sandstone. Within the Michigan basin, oil and natural gas reservoirs are concentrated along the Niagaran reef trend and Devonian Antrim Shales in the northwestern and southern margins of the basin. Enhanced oil recovery has only been applied to a relatively small percentage of fields in the Region. Studies have suggested that a large amount of oil and gas remains in place in many reservoirs. Thus, there is high potential for enhanced oil and gas production associated with CO_2 sequestration in the MRCSP Region.

Grand Lake St. Mary's, circa 1890, one of the first sites for over water/off shore drilling in the United States. (Source: Ohio Division of Geological Survey). The MRCSP Region was the birthplace of the North American oil and gas industries.

Drilling operations at the Ohio CO_2 sequestration test well in Tuscarawas County, Ohio.

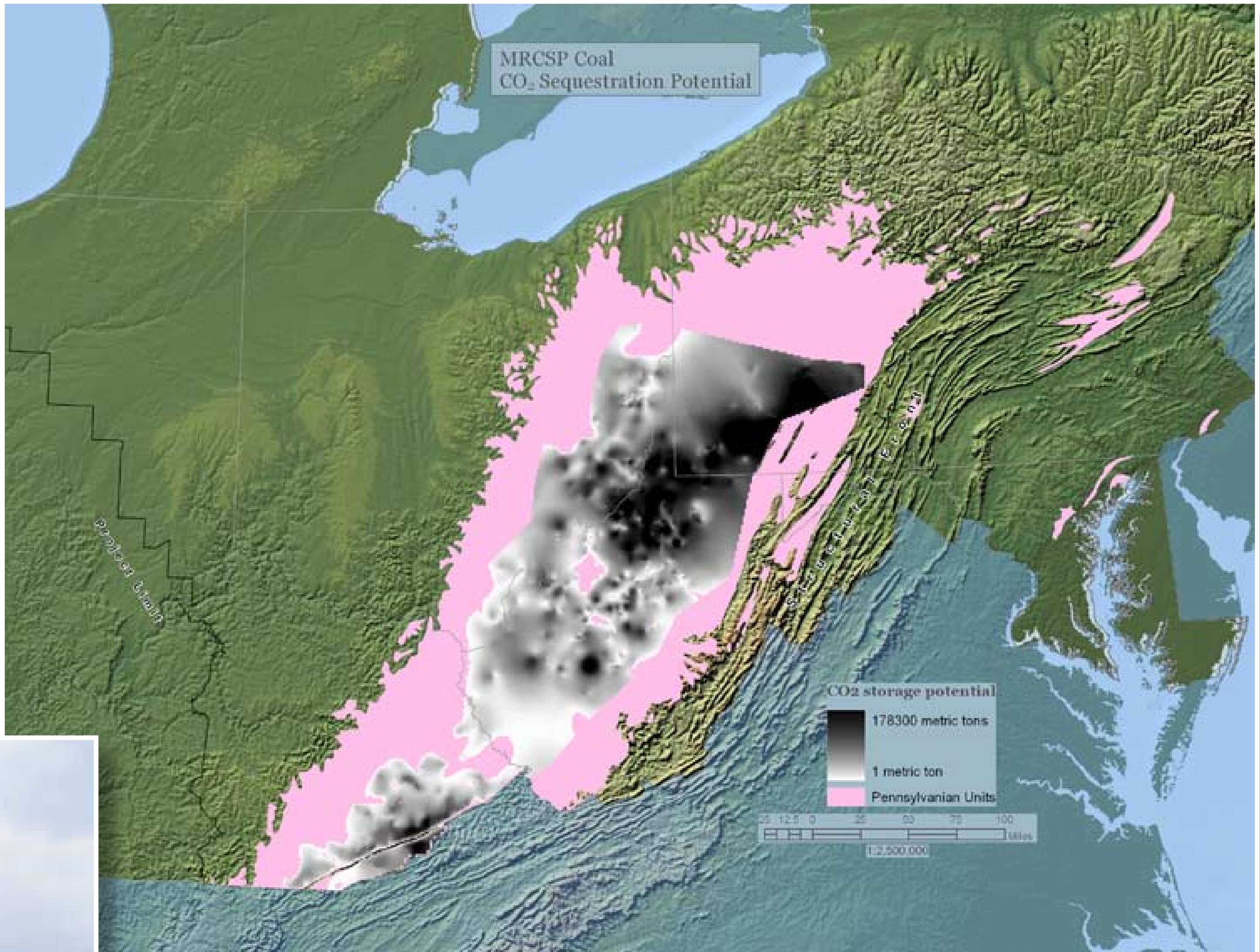
Estimated Oil and Gas Reservoir CO_2 Storage Resource

State	# Fields	Area (acres)	Potential CO_2 Storage Resource (million metric tons)
Northeastern Indiana	181	46,000	61
Eastern Kentucky	69	51,000	87
Michigan	1,348	3,500,000	457
New York	106	1,089,000	272
Ohio	1,807	3,609,000	3,405
Pennsylvania	948	1,129,000	2,806
West Virginia	232	761,000	1,423

MRCSP: Unmineable Coal Seams

The MRCSP Region contains the second- (West Virginia), third- (Kentucky), fourth- (Pennsylvania) and fourteenth- (Ohio) leading coal-producing states in the nation. Bituminous coal seams are located in the Appalachian and Michigan basins and anthracite coal seams are located in the state of Pennsylvania. Analysis of coal seams in the MRCSP Region indicates that up to 1,000 million metric tons (1,100 million tons) of CO_2 may be sequestered in unmineable coal seams in the Appalachian basin alone. Coal seams greater than 500 feet deep in the Appalachian basin with the highest capacity for CO_2 sequestration are located along the Ohio River Valley in Kentucky, Ohio, Pennsylvania, and West Virginia.

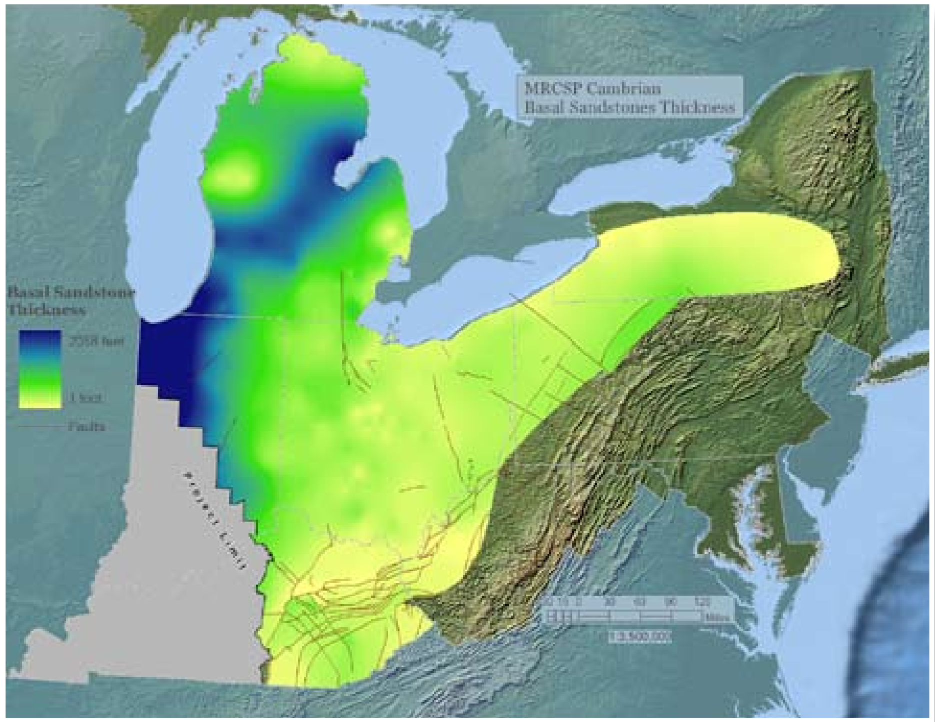
There is also potential for using CO_2 for enhanced CBM recovery in the Appalachian basin. In the last decade, significant CBM production has occurred in some of these historic 'gassy' coals, particularly in southern West Virginia. CBM is locally produced from at least 24 pools in Pennsylvania, and historic and modern CBM fields occur also in the northern portion of West Virginia. Furthermore, CBM production has been reported in eastern Kentucky, and in Ohio, historic CBM production occurred as early as 1924. Although interest in CBM production and exploration is growing in the basin, vast areas remain untested—as well as their CO_2 sequestration potential—and much of the existing data vital in understanding CBM systems is not publicly available.



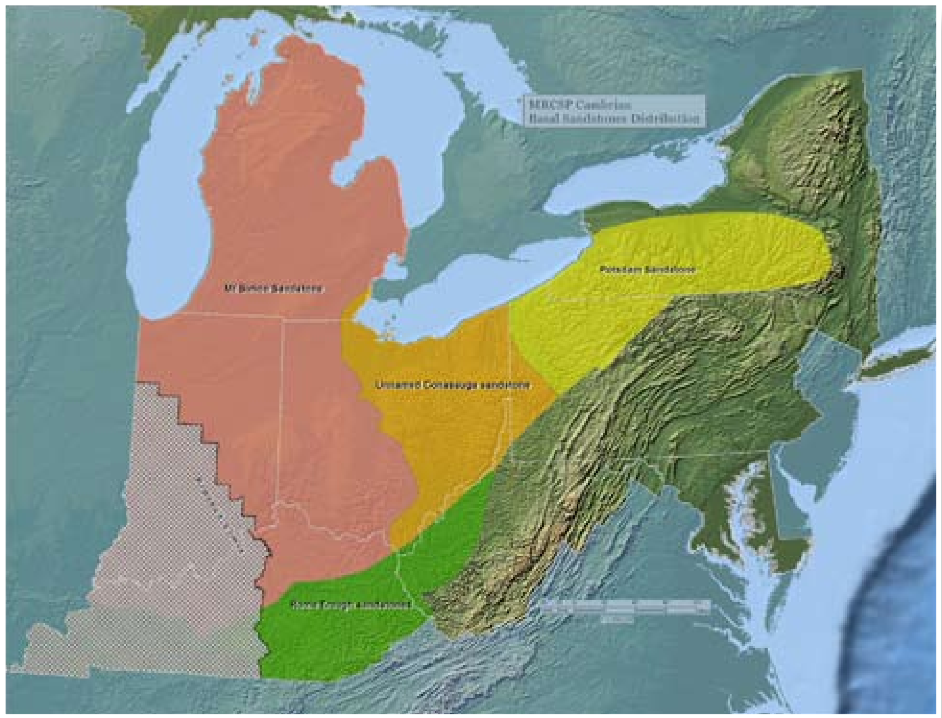
CO_2 sequestration potential in coal seams greater than 500 feet deep (metric tons per square mile).

Coalbed methane well in West Virginia.

Skyland coal bed in Kentucky.



Thickness map for Cambrian age basal sandstones, major deep saline rock targets for geologic sequestration of carbon dioxide in the MRCSP Region.



Map showing the distribution of Cambrian age basal sandstones. The character of this key sequestration target changes with location across the Region.

MRCSP: Deep Saline Formations

Deep saline rock formations are, by far, the MRCSP Region's largest assets for long-term geologic CO_2 sequestration. Initial mapping indicates that the Region's well-defined deep saline formations could potentially sequester several hundred billion metric tons of CO_2. The estimated CO_2 storage resource for the Region is very large compared to the present-day emissions, enough to accommodate CO_2 emissions from large stationary sources for hundreds of years. Saline formations in the MRCSP Region are widespread, close to many large CO_2 sources, and are thought to have large pore volumes available for injection use. However, CO_2 sequestration capacity is not evenly distributed across the Region.

Thick sequences of sedimentary rocks are present throughout most of the MRCSP states in the form of broad basins and arches. The rocks are saturated with dense brine fluids. In addition, the Region is considered a fairly stable geologic setting. The rock formations have been correlated and mapped in the Region in stratigraphic charts based primarily on rocks encountered in oil and gas wells. This data was used to characterize geologic sequestration opportunities in deep saline formations in the MRCSP Region.

The CO_2 storage resource in each reservoir is largely a function of its spatial extent, thickness, and the porosity. Given its presence in much of the MRCSP Region, the deep saline rock formation with the largest CO_2 storage resource in the Region is the Mt. Simon Sandstone, followed by the St. Peter Sandstone and the Medina/Tuscarora Sandstone. Other notable target formations include the Rose Run Sandstone, the Oriskany Sandstone, and the Sylvania Sandstone. Because of the lack of exploratory wells in areas, such as in the deepest portion of the Appalachian basin in Pennsylvania, some areas of the MRCSP Region may have additional storage options. Offshore areas along the East Coast and Great Lakes also contain significant CO_2 storage resource not included in the assessment. While Michigan has the highest storage potential, all of the MRCSP states have capacity to store some CO_2 in deep saline formations.

Estimated Deep Saline Formation CO_2 Storage Resource

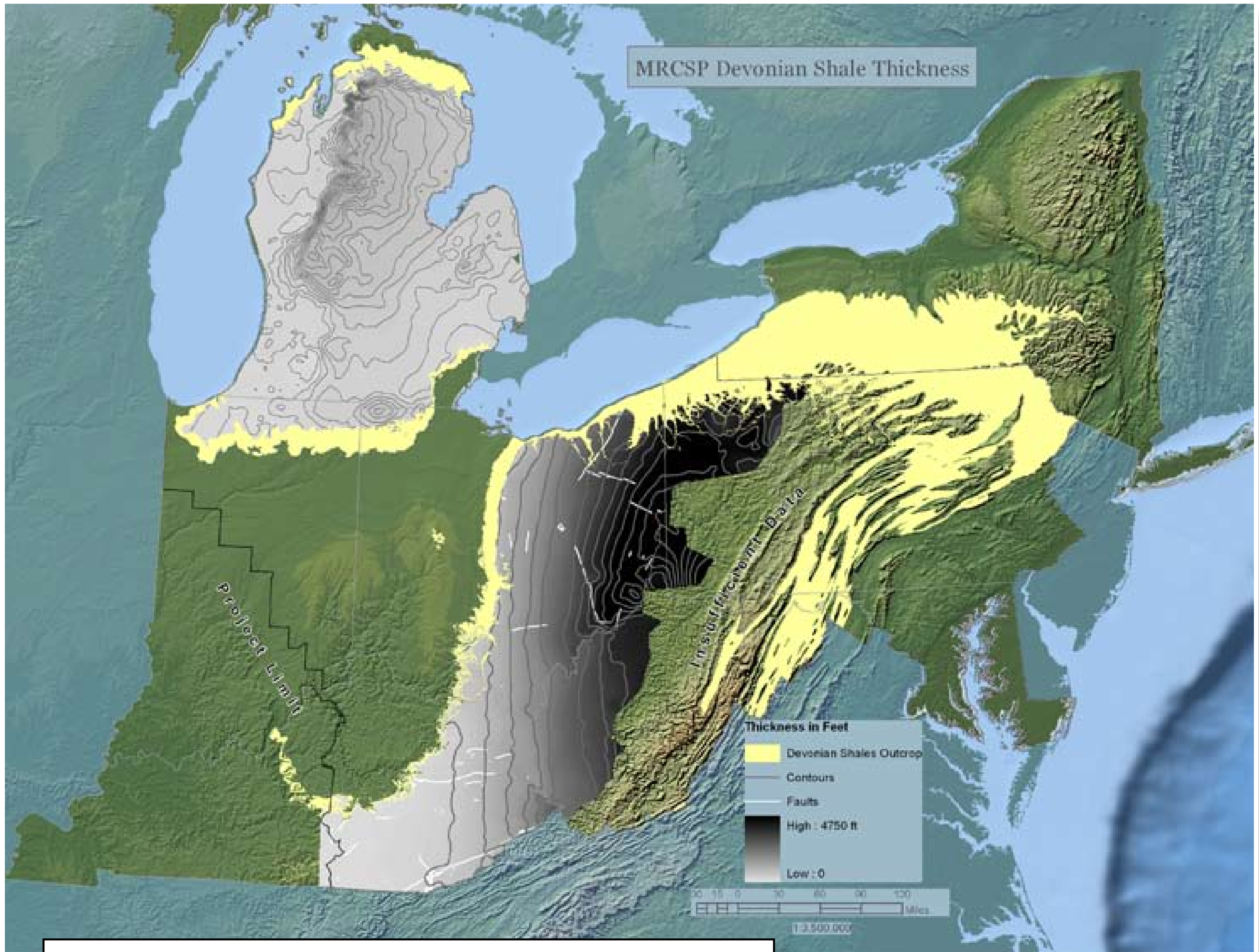
Deep Saline Formation	Potential CO_2 Storage Resource (million metric tons CO_2)	
	Low Estimate (P15)	High Estimate (P85)
Mt. Simon Formation	21,700	86,900
St. Peter Sandstone	8,800	35,300
Medina/Tuscarora Sandstone	7,900	31,500
Rose Run Sandstone	5,700	23,100
Oriskany Sandstone	1,900	7,800
Sylvania Sandstone	1,500	6,000
Wastegate Formation	400	1,800
Basal Conasauga Sandstones	400	1,700
Potsdam Sandstone	1,200	4,500
Rome Trough Sandstones	100	500
TOTAL Deep Saline	49,600	199,100

Rock core collected from a deep saline formation at a depth of 3400 ft below surface at the MRCSP test site in Michigan.

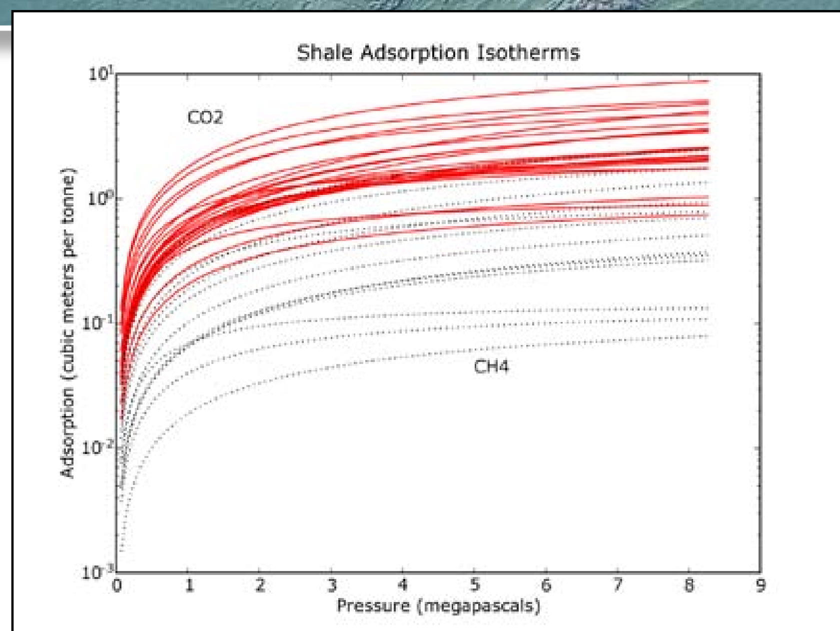
MRCSP Organic Shales

The MRCSP Region contains widespread, thick deposits of organic shales. These shales are interesting in that they are often multifunctional; they act as seals for underlying reservoirs, as source rocks for oil and gas reservoirs, and as unconventional gas reservoirs themselves. Analogous to sequestration in coal beds, CO_2 injection into unconventional carbonaceous shale reservoirs could be used to enhance existing gas production. As an added feature, it is believed the carbonaceous shales would adsorb the CO_2, permitting long-term CO_2 storage, even at relatively shallow depths.

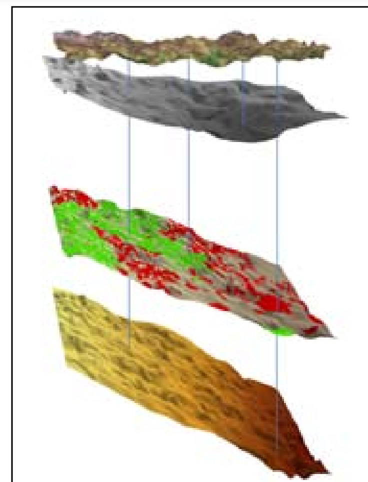
Organic shales are thickest in Kentucky, Ohio, West Virginia and portions of Pennsylvania. In addition, shales are present throughout the Michigan basin. Analysis of these rock formations indicates that they may have the capacity to sequester up to 45,000 million metric tons (50,000 million tons) of CO_2.



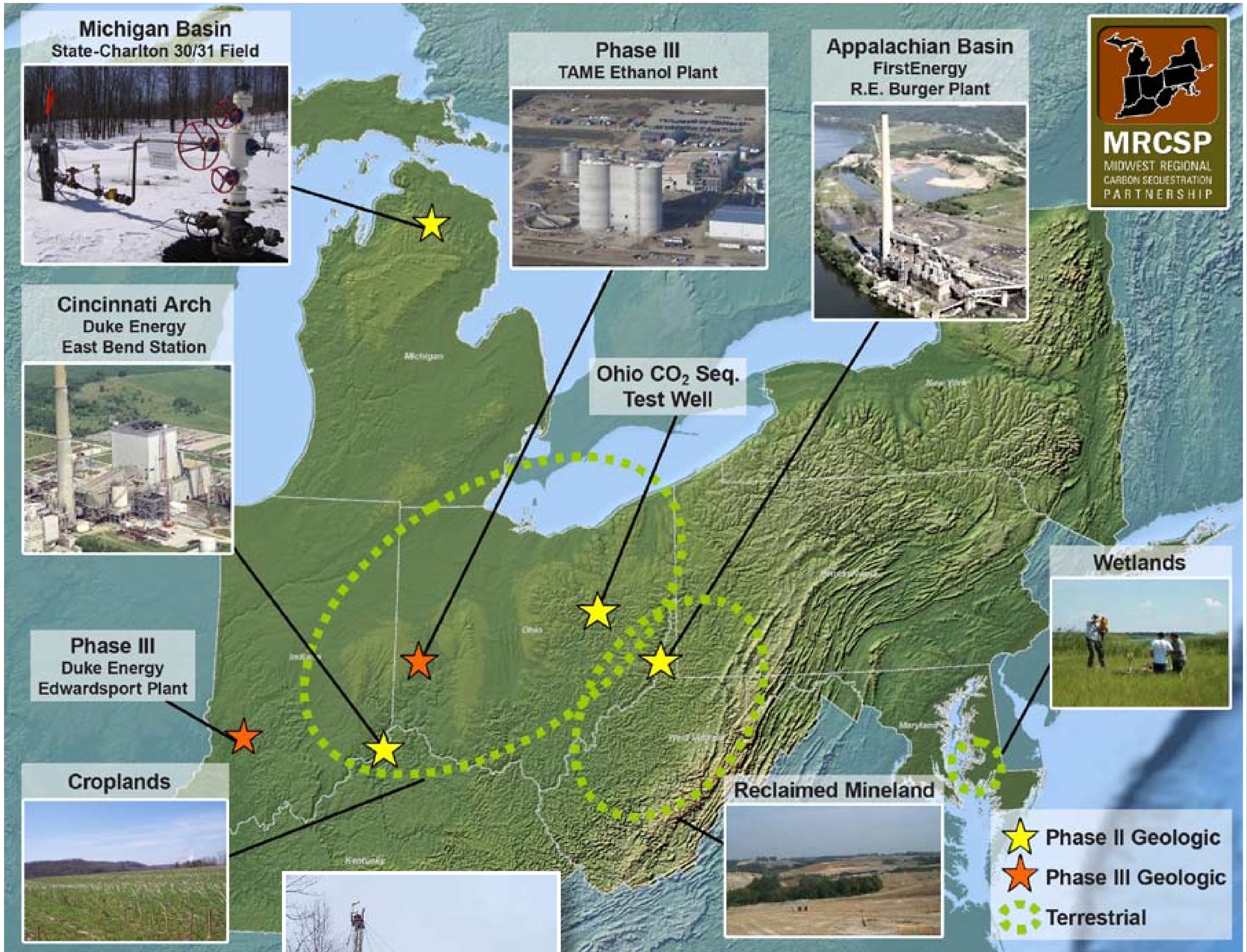
An outcrop of the Devonian Ohio shale in eastern Kentucky.



MRCSP researchers are testing organic shale samples to determine how much CO_2 they will absorb.



Organic shales overlie deeper oil and gas reservoirs and deep saline formations in many parts of the MRCSP (Source: Ohio Division of Geological Survey).




Appalachian Basin geologic test site.


Restored tidal marshes at Blackwater National Wildlife Refuge, Maryland.


Testing at restored tidal marshes at Blackwater National Wildlife Refuge, Maryland.

MRCSP Field Tests

Given the diversity in the Region, the overall approach for MRCSP field tests is to evaluate many different sequestration options in real-world settings. In the first phase of research, the MRCSP characterized carbon sequestration opportunities in the Region by mapping geologic and terrestrial storage formations. The second phase of the program focused on conducting small-scale field tests of sequestration in key areas of the Region. The third phase of the program includes large-scale testing of geologic CO_2 sequestration at an ethanol plant in southwestern Ohio and investigation of sequestration potential for a planned power plant in western Indiana.

Three geologic and three terrestrial field sites were identified to test the safety and effectiveness of carbon sequestration in the Region through a series of focused field tests of sequestration technologies. The field tests should provide meaningful results for the entire Region, with the added benefit of examining technical and economic aspects of carbon capture and storage.

Geologic tests are planned along distinct, regional geologic features within the MRCSP Region:

Validation Phase Geologic Test Sites

- Appalachian basin, FirstEnergy R.E. Burger Plant, Shadyside, OH
- Cincinnati arch, Duke Energy East Bend Station, Rabbit Hash, KY
- Michigan basin, State-Charlton 30/31 Field, Otsego Co., MI
- Ohio CO_2 test well, Tuscarawas Co., OH

Development Phase Geologic Test Sites

- The Andersons Marathon Ethanol Plant, Greenville, OH (primary site)
- Duke Energy Edwardsport Plant, Edwardsport, IN (optional site)

MRCSP researchers are studying the amount of carbon that may be stored in forest planted on marginal lands in the Region.

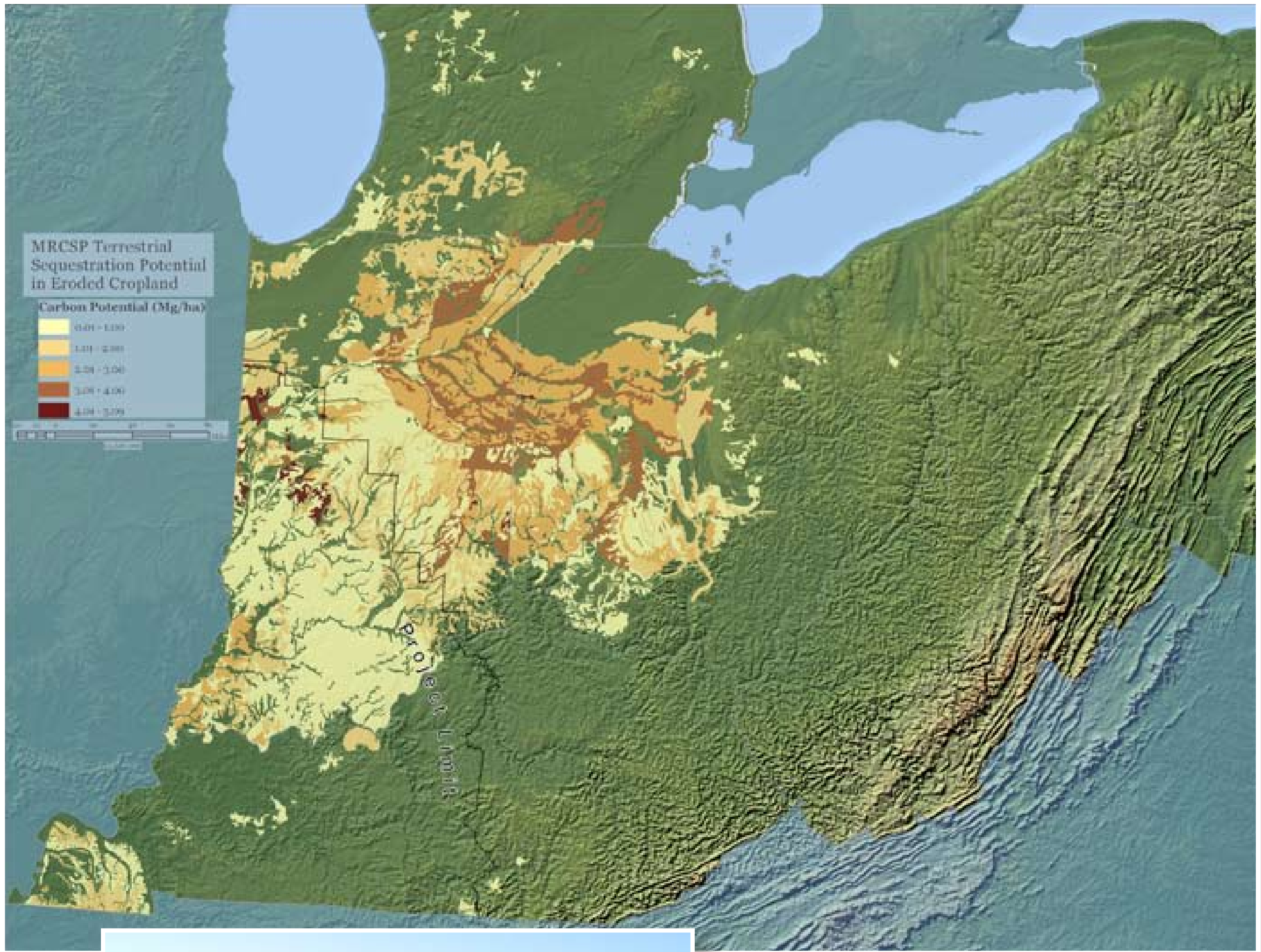
The general methodology for each site is to characterize the deep rock layers, drill test wells, perform limited CO_2 injection tests, monitor the injected CO_2, and evaluate the sequestration process as it applies to the region.

Terrestrial sequestration tests are planned at croplands, reclaimed mineland areas, and wetlands. The objective of these tests is to measure the potential increase in carbon sequestration with different farming and land-use practices. This field work is designed to quantify the actual carbon sequestration possible in these environments.

Along with the field tests, a thorough stakeholder outreach effort is underway to communicate project progress to the local community, general public, and scientific community. In addition, research is being performed to develop a regulatory framework for sequestration, characterize additional geologic targets, and develop carbon capture technologies suitable for sources in the Region.

The MRCSP Michigan basin field test was concluded in March 2008 after successful injection of 10,241 metric tons CO_2 into a deep saline rock formation called the Bass Islands Dolomite at a depth of 3,400–3,500 ft.

Seismic survey trucks move along a rock outcrop at the Appalachian basin R.E. site.



MRCSP Terrestrial Opportunities

Terrestrial ecosystems in the MRCSP states offer a viable opportunity for carbon sequestration because of the extensive farmlands, wetlands, minelands, and forests in the Region. There are over 22 million hectares (or 88,000 square miles) of land in the MRCSP Region that could be utilized for enhanced carbon sequestration. Studies on the Region have shown that there is potential to sequester 144 million metric tons (159 million tons) of CO_2 per year in croplands, marginal lands, minelands, and wetlands (total emissions from large stationary sources in the MRCSP Region are approximately 765 million metric tons (843 million tons) of CO_2 per year). Tests are being conducted to demonstrate carbon sequestration through improved agriculture management practices for farmers in marginal and non-marginal cropland areas. Studies on tidal marsh areas are also underway to determine how to maximize terrestrial carbon sequestration in wetland areas and minimize decomposition. Finally, surface mining areas are being tested to determine the amount of carbon sequestration that may be achieved in reclaimed minelands.

Restored tidal marshes at the MRCSP terrestrial test site at the Blackwater National Wildlife Refuge, Maryland.

MRCSP terrestrial sequestration test site in Coshocton County, Ohio.

Sequestration Potential (million metric tons CO_2/year)

Category	Area (Mha)	IN	KY	MD	MI	OH	PA	WV	Total
Cropland	10.7	4.4	1.1	0	3.7	4	0.4	0	14
Eroded Cropland	1.6	6.6	0	0	0.7	4	0	0	11
Marginal Land (Forest)	6.5	19.5	16.9	3.7	16.2	17.7	17.7	7.7	99
Mineland	0.6	0	0.7	0.4	0.7	0.7	1.1	1.8	6
Wetland	3.4	2.9	0	1.8	8.8	0.7	0	0	14
TOTAL	22.8	33.5	18.8	5.9	30.2	27.2	19.1	9.6	144

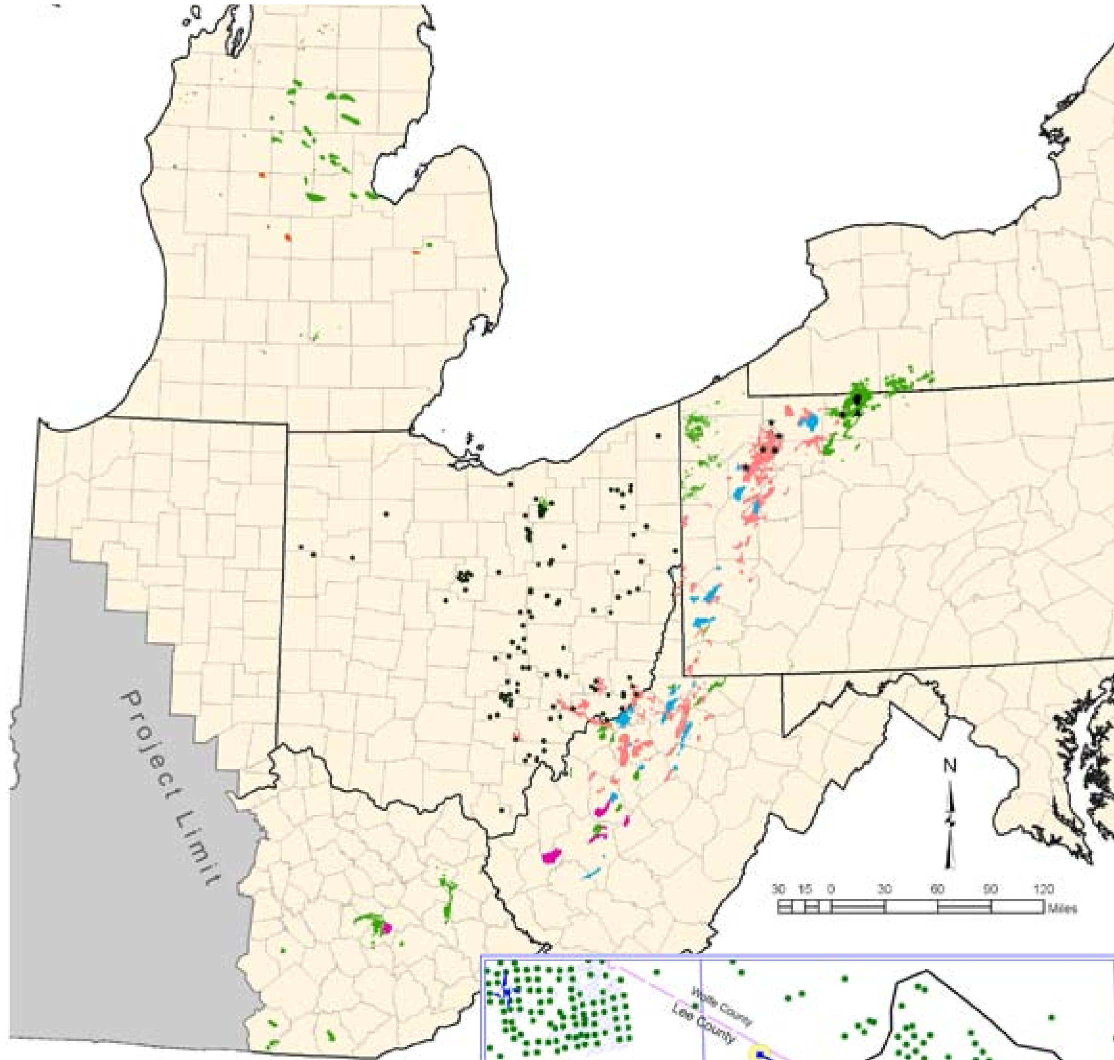
*Mha = million hectares

MRCSP Commercialization Opportunities

The MRCSP Region has many large anthropogenic CO_2 stationary sources that are in close proximity to the Region's geologic CO_2 storage formations, thus making them potential candidates for CO_2 capture and storage commercialization. These opportunities include ethanol plants, new coal-fired power plants, retrofitting existing coal-fired power plants, coal-to-liquid facilities, EOR, ECBM, refineries, landfills, and gas processing facilities. Plans for a significant number of electric generating capacity developments are underway for the MRCSP Region, with the addition of over 10,000 MW of capacity predicted over the next decade. MRCSP analysis has also shown that there are a number of emerging technologies that show promise for improving the economics of CO_2 capture. The Region's industrial makeup has provided impetus for moving forward with CCS, and several projects are in various stages of development.

In addition to the DOE regional partnership, several field projects, state-level organizations and regulatory initiatives have been started to advance CCS:

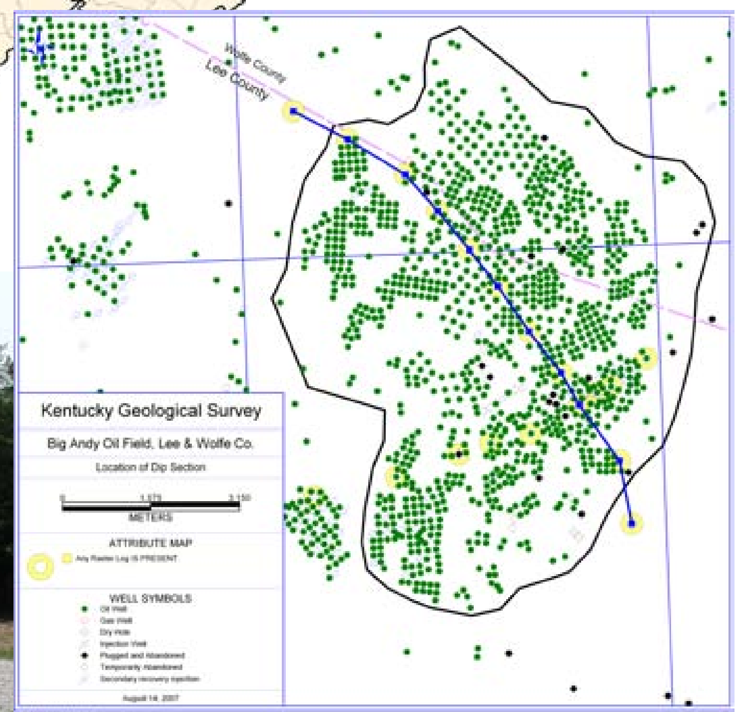
- Integrated CCS demonstration with chilled ammonia capture technology with injection and monitoring in two saline formations at American Electric Power's Mountaineer Plant in West Virginia
- Kentucky Consortium for Carbon Sequestration
- Ohio CO_2 sequestration stratigraphic test well in Tuscarawas County, Ohio (no CO_2 injected)
- Pennsylvania Carbon Management Advisory Group
- The Midwestern Governors' Association Midwestern Regional Greenhouse Gas Reduction Accord (Michigan = member, Indiana and Ohio = observer)
- Regional Greenhouse Gas Initiative (Maryland and New York)



Map showing historic EOR projects in MRCSP Region.

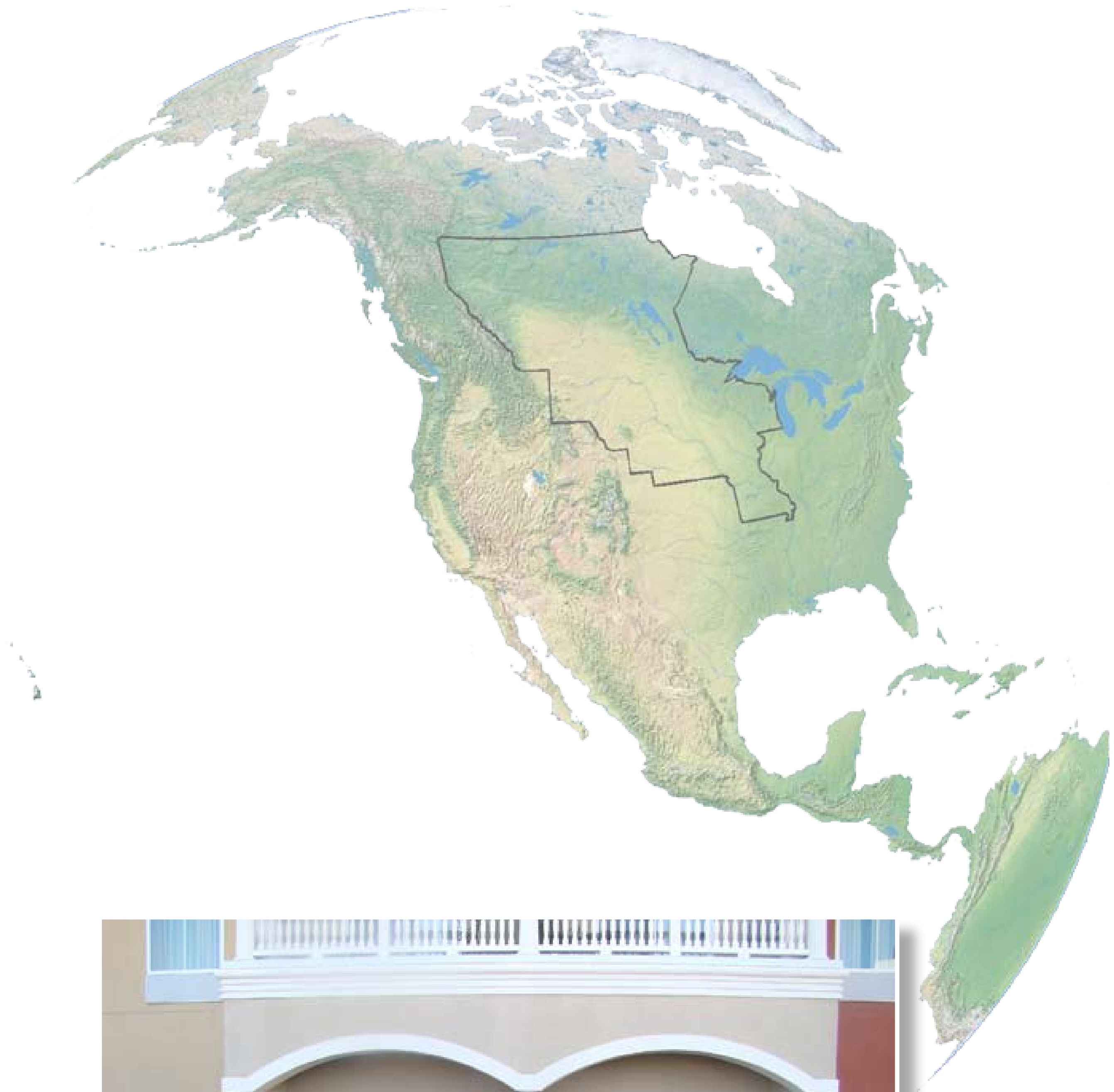
In the MRCSP states, dedicated CO_2 pipelines will be the primary means of transporting CO_2 from the stationary source to a suitable, long-term geologic storage site. While little CO_2 pipeline exists in the Region, an extensive natural gas distribution network is present, with an established technical and regulatory framework.

Many oil fields in the MRCSP Region are candidates for CO_2 miscible-flooding for EOR. Criteria in evaluating potential candidates for CO_2 miscible floods include depth, oil gravity, cumulative production, net pay thickness, and minimum miscibility pressure. Within the project area, ongoing CO_2 injection projects include the Niagaran reef reservoirs (Silurian) in the Dover field in Michigan and the Keefer Sandstone reservoir (Silurian) in the Big Andy field in Kentucky. Pilot CO_2 floods in the Big Injun and Berea Sandstone (Mississippian and Devonian) were conducted in the late 1970s and early 1980s in West Virginia. Some reservoirs in the Region have over 90 percent of the original oil remaining in place and large potential for additional production. There is also potential for enhanced coal bed methane recovery in portions of West Virginia, Pennsylvania, Kentucky, and Ohio.



Map of Big Andy EOR Field in Kentucky.

EOR CO_2 injection at Big Andy Field in Kentucky.



The Plains CO_2 Reduction Partnership

The Plains CO_2 Reduction (PCOR) Partnership is investigating and demonstrating various sequestration technologies to provide a safe, effective, and efficient means of managing CO_2 emissions across central North America.

The regional characterization activities conducted by PCOR Partnership confirmed that while numerous large stationary CO_2 sources are present, the Region also has tremendous potential for CO_2 sequestration. The varying natures of the sources and sequestration sites reflect the geographic and socioeconomic diversity across this nearly 3.6 million km^2 (1.4 million mi^2) of central North America. In the upper Mississippi River Valley and along the shores of the Great Lakes Michigan and Superior, large coal-fired electrical generators power the manufacturing plants and breweries of St. Louis, Minneapolis, and Milwaukee. To the west, the prairies and badlands of the north-central United States and central Canada are home to coal-fired power plants, natural gas-processing plants, ethanol plants, and refineries that further fuel the industrial and domestic needs of cities throughout North America. The PCOR Partnership Region is also rich in agricultural lands that hold tremendous potential for terrestrial sequestration. The Prairie Pothole Region (PPR) that stretches from northwestern Iowa, across the Dakotas, and into Saskatchewan and Alberta holds promise as an area that can provide a significant terrestrial CO_2 sequestration site.

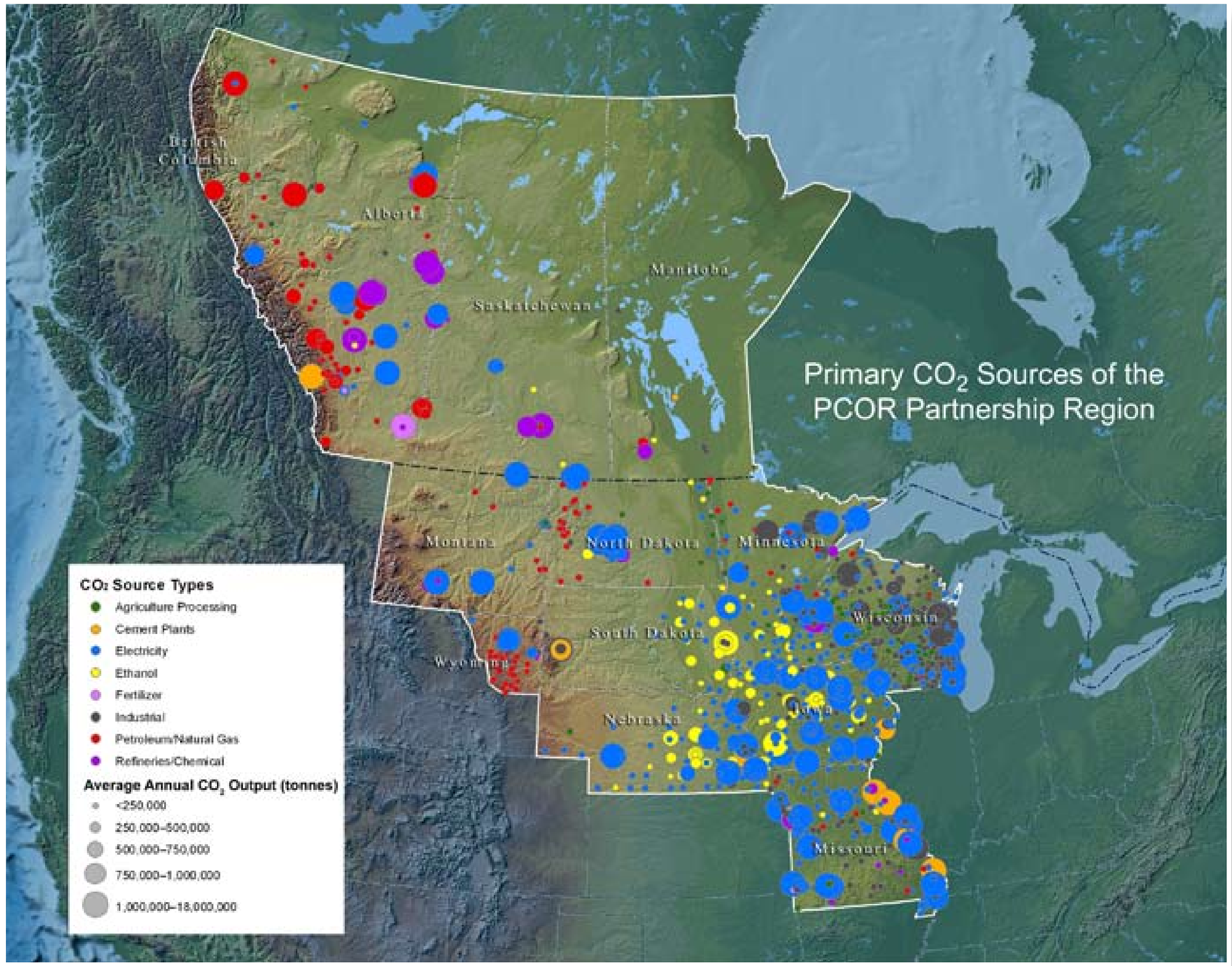
Deep beneath the surface of the region lie geologic formations that hold tremendous potential to store CO_2. Oil fields, already considered to be capable of sequestering CO_2, can be found in roughly half the region, while formations of limestone, sandstone, and coal suitable for CO_2 storage exist in basins that, in some cases, extend over thousands of square miles. In many cases, large sources in the Region are proximally located to large-volume sequestration sites, and in some cases, key infrastructure is already in place. The PCOR Partnership is a collaboration of more than 75 public- and private-sector stakeholders from the central interior of North America and adjacent areas that have expertise in power generation, oil and gas exploration and production, geology, engineering, the environment, agriculture, forestry, and economics. The partners are the backbone of the PCOR Partnership and provide data, guidance, and practical experience with direct and indirect sequestration, including value-added projects.

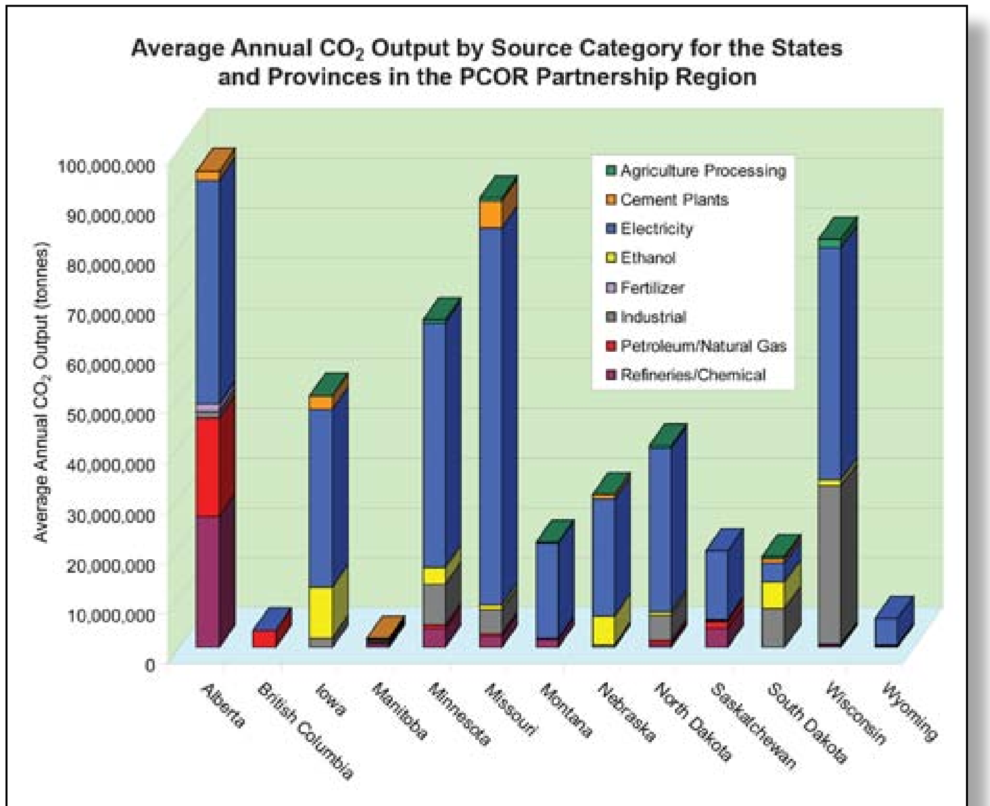
PCOR Partnership Members at the 2007 Annual Meeting.

PCOR Partnership: CO_2 Sources

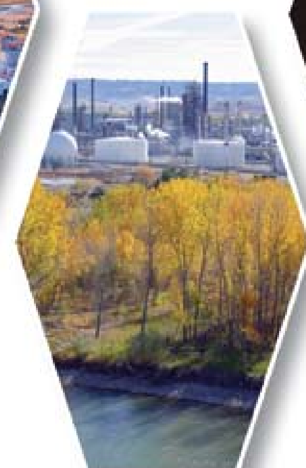
The PCOR Partnership project has identified, quantified, and categorized 1,545 stationary CO_2 sources in the Region. These stationary sources have a combined annual CO_2 output of nearly 522 million metric tons (575 million tons). And, although not a target source of CO_2 for direct sequestration, the transportation sector contributes nearly 202 million metric tons (223 million tons) of additional CO_2 to the atmosphere every year.

The annual output from the various stationary sources ranges from 9 million to 16 million metric tons (10 to 18 million tons) for the larger coal-fired electric generation facilities, to under 4,500 metric tons (5,000 tons) for industrial and agricultural processing facilities. In some cases, the distribution of the sources with the largest CO_2 output coincides with the availability of fossil fuel resources, namely, coal, natural gas, and oil. This relationship is significant with respect to geologic sequestration opportunities. Many of the smaller sources are concentrated around more heavily industrialized metropolitan regions such as southeastern Minnesota, southeastern Wisconsin, and eastern Missouri.





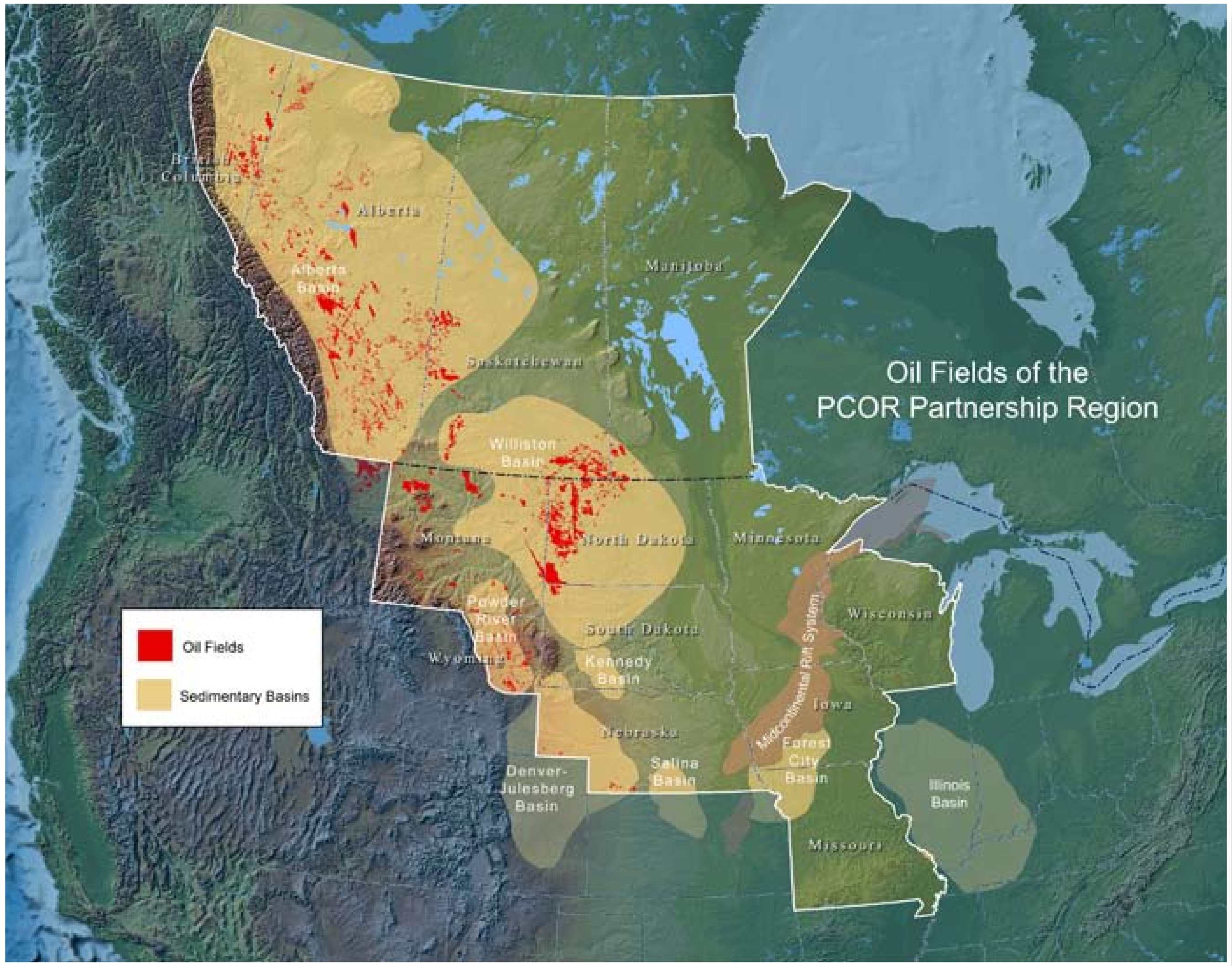

Ethanol Plant


Refinery


Gas Processing Plant


Cement Plant


Electric Generation Plant



Geologic Sequestration: Oil and Gas

The geology of CO_2 sequestration is analogous to the geology of petroleum exploration; the search for oil is the search for sequestered hydrocarbons. Oil fields have many characteristics that make them excellent target locations for geologic storage of CO_2. Therefore, the geologic conditions that are conducive to hydrocarbon storage are also the conditions that are conducive to CO_2 sequestration. The three requirements for storing hydrocarbons are a hydrocarbon source, a suitable reservoir, and an impermeable trap. These requirements are the same as for sequestering CO_2.

A single oil field can have multiple zones of accumulation which are commonly referred to as pools, although specific legal definitions of fields, pools, and reservoirs can vary in a particular state or province. Once injected into an oil field, CO_2 may be sequestered in a pool through dissolution into the formation fluids (oil and/or water), located as a buoyant supercritical-phase CO_2 plume at the top of the reservoir (depending on the location of the injection zone within the reservoir), and/or mineralized through geochemical reactions between the CO_2, formation waters, and the formation rock matrix.

Oil is drawn from the many oil fields in the PCOR Partnership Region from depths ranging from 760 to 1,200 m (2,500 to 4,000 ft) for the shallower pools to 3,700 to 4,900 m (12,000 to 16,000 ft) for the deepest pools.

Storage and Incremental Recovery Through EOR in Selected Fields

Basin	Cumulative Recovery, million bbl	CO_2 Sequestration Potential, Bcf	CO_2 Sequestration Potential, million metric tons
Williston	1,023	8,186	455
Powder River	381	3,049	170
Denver-Julesberg	25	199	11
Alberta	6,000	4,856	2,282

Although oil was discovered in this Region in the late 1800s, significant development and exploration did not begin until the late 1940s and early 1950s. The body of knowledge gained in the past 60 years of exploration and production of hydrocarbons in this Region is a significant step toward understanding the mechanisms for secure sequestration of significant amounts of CO_2.

Geologic Sequestration: Unmineable Coal

Many coal seams throughout central North America are too deep or too thin to be mined economically. However, many of these coals have varying amounts of methane adsorbed onto pore surfaces, and wells can be drilled into the coal beds to recover this "coalbed methane" (CBM). In fact, CBM is the fastest growing source of natural gas in the United States and accounted for 7.2 percent of domestic production in 2003.

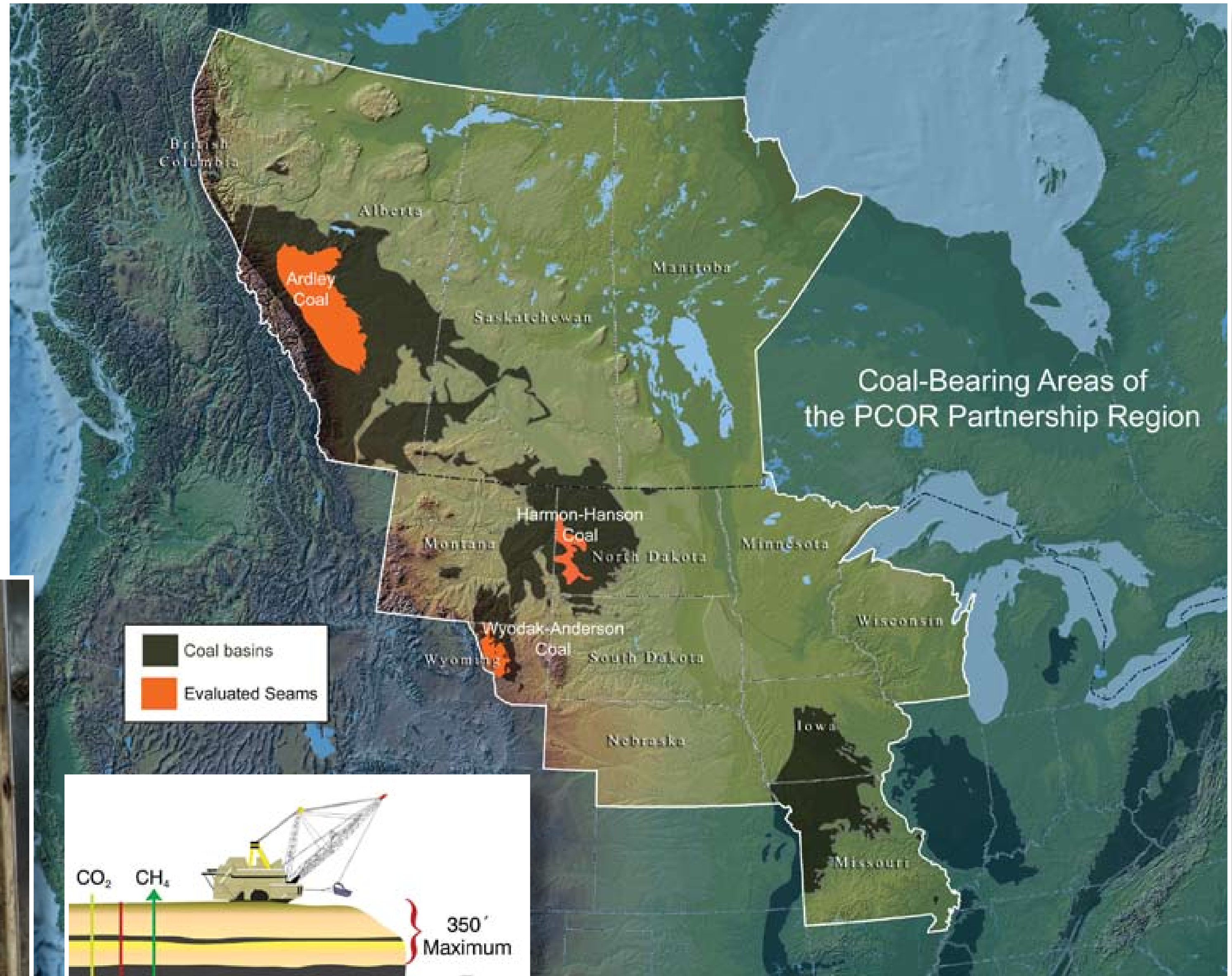
As with oil reservoirs, the initial CBM recovery methods, dewatering and depressurization, can leave methane in the coal seam. Additional CBM recovery can be achieved by sweeping the coal bed with CO_2, which preferentially adsorbs onto the surface of the coal, displacing the methane. For the coals in the PCOR Partnership Region, up to 13 molecules of CO_2 can be adsorbed for each molecule of methane released, thereby providing an excellent storage possibility for CO_2. Just as with depleting oil reservoirs, unmineable coal beds are a good opportunity for CO_2 storage.

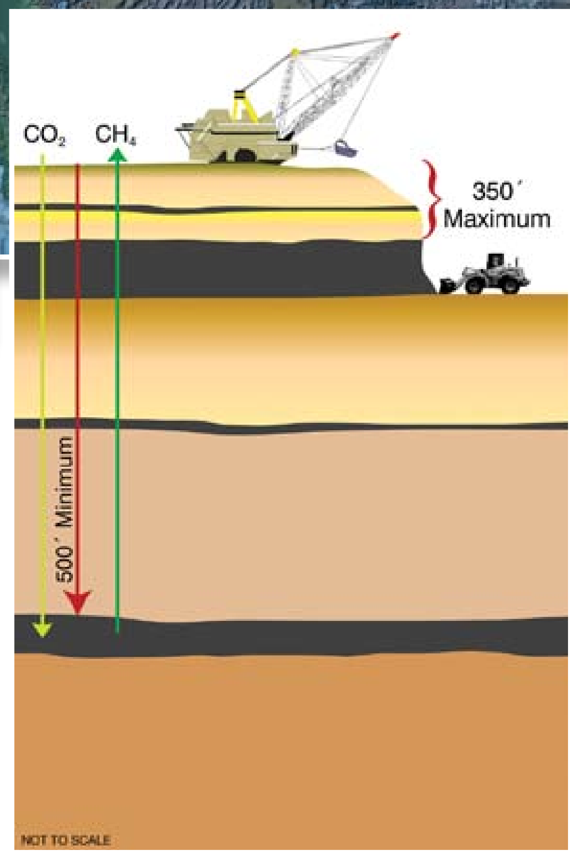
Three major coal horizons in the PCOR Partnership Region have been identified for further study: the Wyodak–Anderson bed in the Powder River Basin, the Harmon–Hanson interval in the Williston Basin, and the Ardley coal zone in the Alberta Basin. The CO_2 sequestration potential estimated for these three coal horizons is approximately 7.3 billion metric tons (8.0 billion tons).

Preparing to take a core sample from a lignite bed in the Williston Basin.

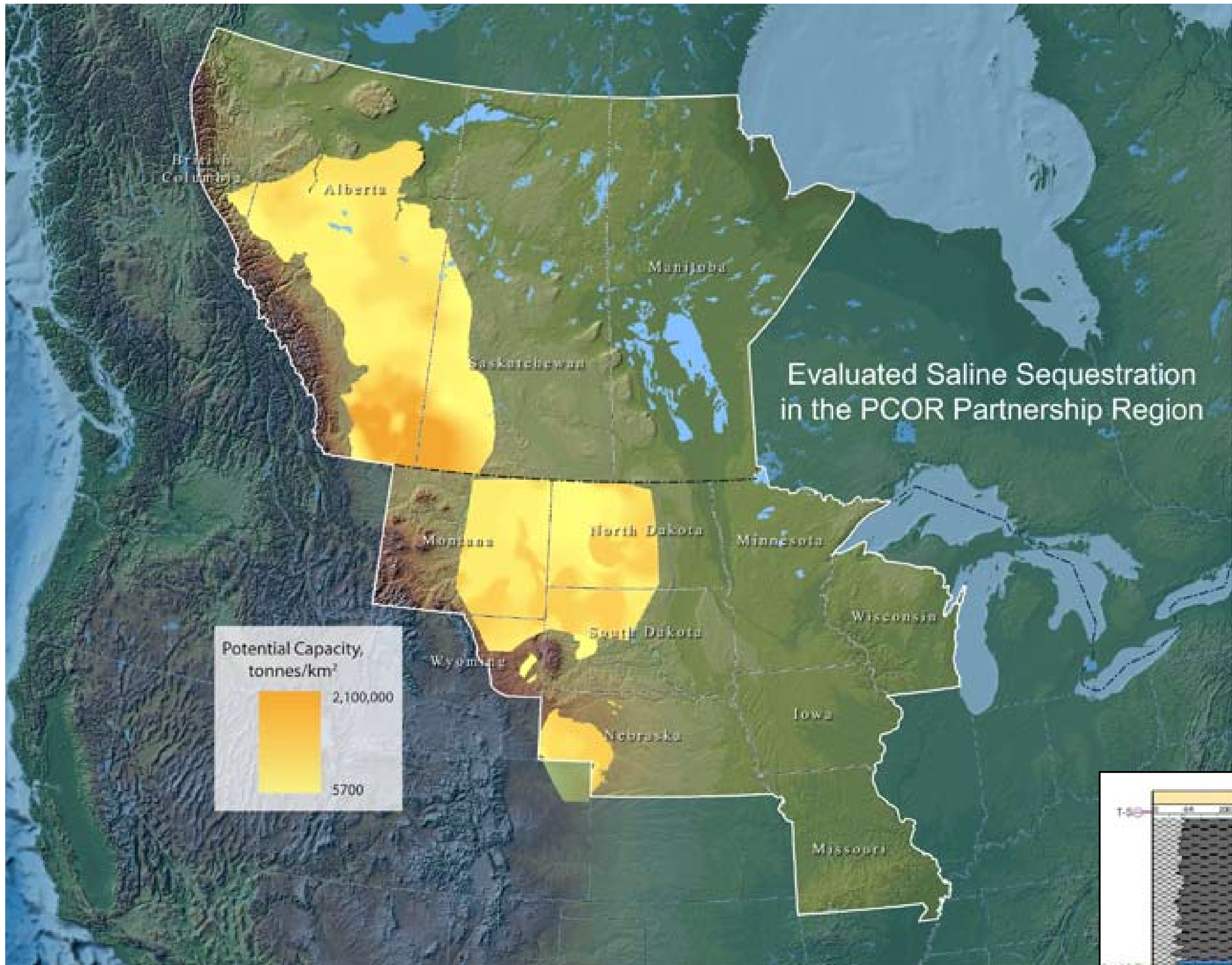
In northeastern Wyoming, the estimated CO_2 sequestration potential for the areas where the coal overburden thickness is > 305 m (1,000 ft) is 6.2 billion metric tons (6.8 billion tons). The coal resources that underlie these deep areas could potentially sequester all of the current annual CO_2 emissions from nearby power plants for the next 156 years.

Current efforts include the Validation Phase site in northwestern North Dakota and collaboration with the Iowa and Missouri Geological Surveys to evaluate the potential for sequestration in the coal seams in the southeastern portion of the PCOR Partnership Region.

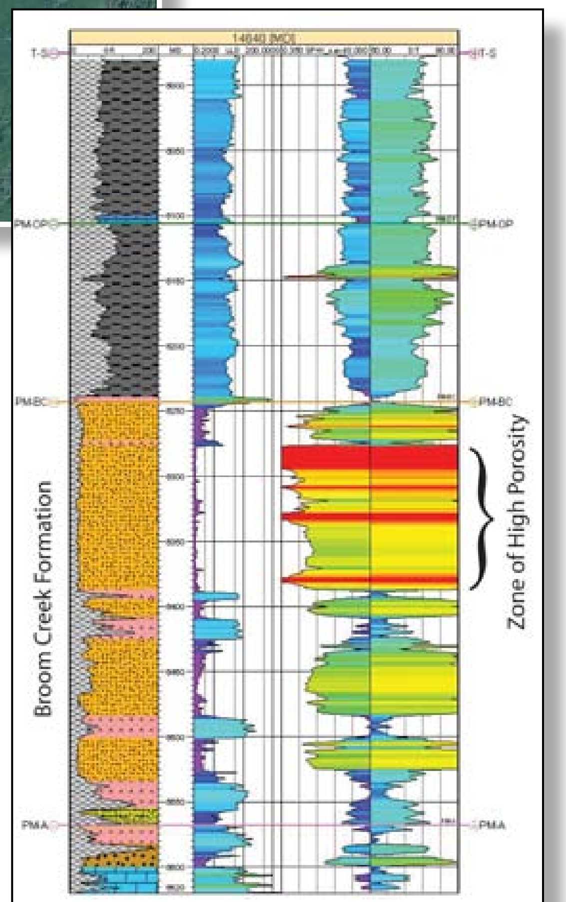




Schematic of enhanced CBM recovery.



Formation	Basin	Estimated CO_2 Capacity, billion tonnes
Lower Cretaceous System		
Newcastle Formation	Williston and Powder River	1
Viking Formation	Alberta	60
Maha Formation	Denver–Julesberg	3
Permian System		
Broom Creek Formation	Williston	5
Mississippian System		
Madison Formation	Williston and Powder River	37



Geologic Sequestration: Deep Saline Formations

Saline formations within the PCOR Partnership Region have the potential to store vast quantities of anthropogenic CO_2. In the earliest phase of the project, two saline formations, the Mississippian Madison and the Lower Cretaceous, were evaluated on a broad regional basis using published data.

More recent efforts have focused on creating higher resolution petrophysical models for a series of four stacked saline formations in west-central North Dakota.

The lateral extent of these formations, the current understanding of their storage potential gained through injection well performance, and the geographic proximity to major CO_2 sources suggest the formations may be suitable storage for future CO_2 sequestration.

Efforts are also under way in cooperation with the Geological Surveys of Minnesota, Missouri, and Iowa to assess saline formation sequestration potential in their respective states.

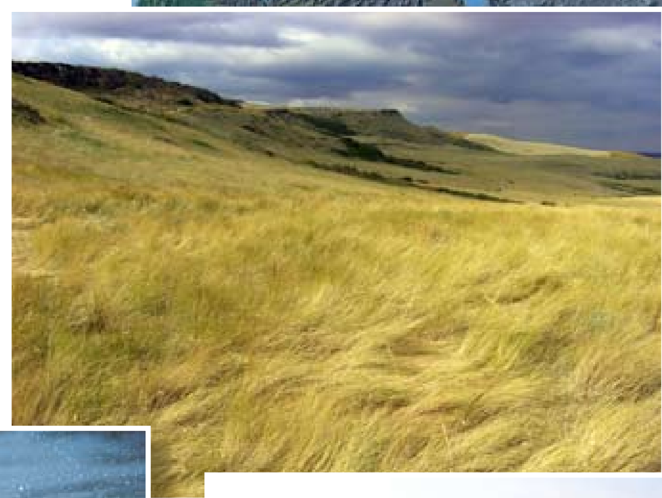
State-of-the-art petrophysical modeling is used to derive resource estimates for multiple saline formations in the Williston Basin. This geophysical well log identifies zones of high porosity in the sands of the Broom Creek Formation at depths between 6,250 and 6,550 feet. These sands are excellent target zones for the injection of CO_2 in west-central North Dakota.

Terrestrial Sequestration

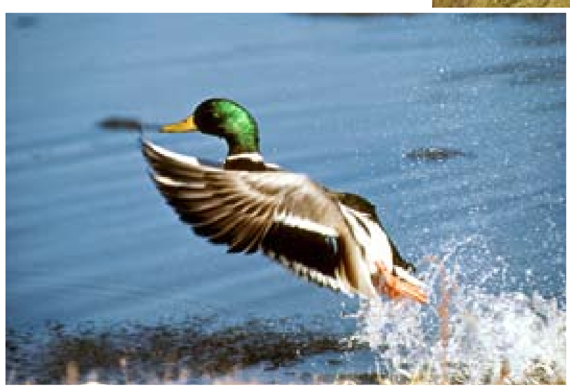
In contrast to geologic sequestration deep within the earth, the concept of terrestrial sequestration focuses on a more natural mechanism of CO_2 storage in vegetation and soils within a few feet of the surface. From the Central Lowlands' forests and cropland in the southeastern portion of the region, through the expansive grasslands and croplands of the northern Great Plains, to the northern boreal forests of Canada, much of the PCOR Partnership Region has a rich agrarian history founded on fertile soils. However, as central North America developed into the pattern of land use seen today, much of the original soil carbon has been lost to the atmosphere. In this setting, the most promising potential to sequester carbon would be to convert marginal agricultural lands and degraded lands back to grasslands, wetlands, and forests when favorable conditions exist.

The PCOR Partnership Region includes the Prairie Pothole Region, a major biogeographical region that encompasses approximately 347,000 mi^2 (899,000 km^2) and includes portions of Iowa, Minnesota, Montana, North Dakota, and South Dakota in the United States and Alberta, Saskatchewan, and Manitoba in Canada. Formed by glacial events, this Region historically was dominated by grasslands interspersed with shallow palustrine wetlands. Prior to European settlement, this Region may have supported more than 48 million acres of wetlands, making it the largest wetland complex in North America. However, fertile soils in this Region resulted in the extensive loss of native wetlands as cultivated agriculture became the dominant land use. Because of oxidation of organic matter by cultivation, agriculture has resulted in the depletion of soil organic carbon (SOC) in wetlands.

Recently, in PCOR Partnership efforts conducted at wetlands study sites by U.S. Geological Survey and Ducks Unlimited, Inc., scientists demonstrated that restoration of previously farmed wetlands results in the rapid replenishment of SOC lost to cultivation at an average rate of 1 metric ton per acre per year. Restored prairie wetlands and grasslands provide a unique and previously overlooked opportunity to store atmospheric carbon in the PCOR Partnership Region.



Grasslands of Alberta.



Survey of soil organic carbon.

Pothole region of central North Dakota.

Field Validation and Development Sites

Validation Phase

In the fall of 2005, the PCOR Partnership embarked on a 4-year field verification program designed to enhance the local expertise, experience, and working relationships needed to develop and demonstrate practical and environmentally sound sequestration opportunities in the Region. An overall goal of the Validation Phase is to validate the most promising sequestration technologies and infrastructure concepts identified in Characterization Phase activities and to refine the regional characterization efforts started in this Phase. Four field validation tests were developed to test the efficacy of CO_2 sequestration. Results of the activities will include: (1) technical data and reports; (2) television documentaries; (3) enhanced working relationships between government, regulatory, industrial, and citizen groups with respect to CO_2 sequestration; (4) an enhanced assessment of terrestrial and geologic sequestration potential in the region; and (5) an improved assessment of regional economic opportunities with respect to enhanced production of oil and gas resources.

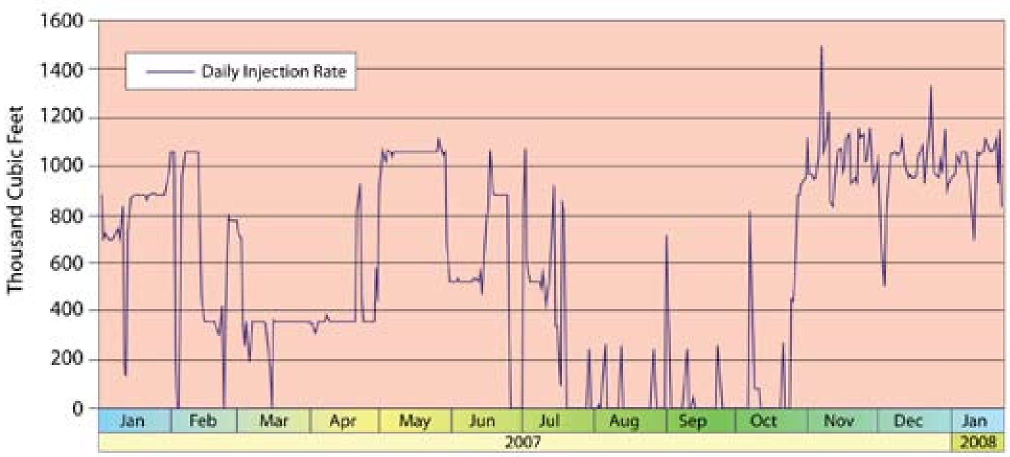
Development Phase

The Development Phase for PCOR Partnership features two commercial-scale demonstrations of geologic sequestration of anthropogenic CO_2. These two demonstrations, the Western Canadian Basin Demonstration in northeastern British Columbia and the Williston Basin Demonstration in western North Dakota, are designed to sequester a total of over 10 million metric tons (11 million tons) of CO_2 by 2017 in deep, well-characterized, underground storage reservoirs. The primary objectives of the Development Phase are (1) to gather characterization data to verify the ability of the target formations to store CO_2, (2) to develop the infrastructure required to transport CO_2 from the source to the injection site, (3) to facilitate development of the rapidly evolving North American regulatory and permitting framework, and (4) to develop a mechanism by which carbon credits can be monetized for CO_2 sequestered in geologic formations.

Validation Phase Field Sites

CO_2-rich Gas in a Pinnacle Reef Structure – The field validation test being conducted in the Zama Field of northern Alberta, Canada, is evaluating the potential for geologic sequestration of CO_2 as part of a gas stream that also includes high concentrations of hydrogen sulfide (H_2S). Acid gas (70% CO_2, 30% H_2S) from the Zama natural-gas-processing plant is being injected at a depth of 1,500 m (4,900 ft) into an oil-producing pinnacle reef structure for the dual purposes of CO_2 sequestration and tertiary EOR. Through January of 2008, the project injected over 10,880 metric tons (12,000 tons) of acid gas and is expected to exceed 54,420 metric tons (60,000 tons) through the project end in 2009.

Results of the Zama activities are providing insight regarding the impact of impurities on formation integrity (i.e., potential seal degradation), MVA techniques, and EOR success within a carbonate reservoir and will be used to create best management practice scenarios for geologic storage applications of this type. In March 2007, the project was recognized by the Carbon Sequestration Leadership Forum (CSLF) as a niche area that will further develop the knowledge base required for large-scale deployment of carbon sequestration.



CO_2 in a Deep Oil Reservoir – CO_2 will be injected into an oil-bearing zone at great depth in an oil field in western North Dakota. The activity will be used to determine the efficacy of CO_2 sequestration and the use of CO_2 to produce additional oil from deep carbonate source rocks. Efforts conducted in this field validation test will facilitate the implementation of the Development Phase Williston Basin demonstration test.

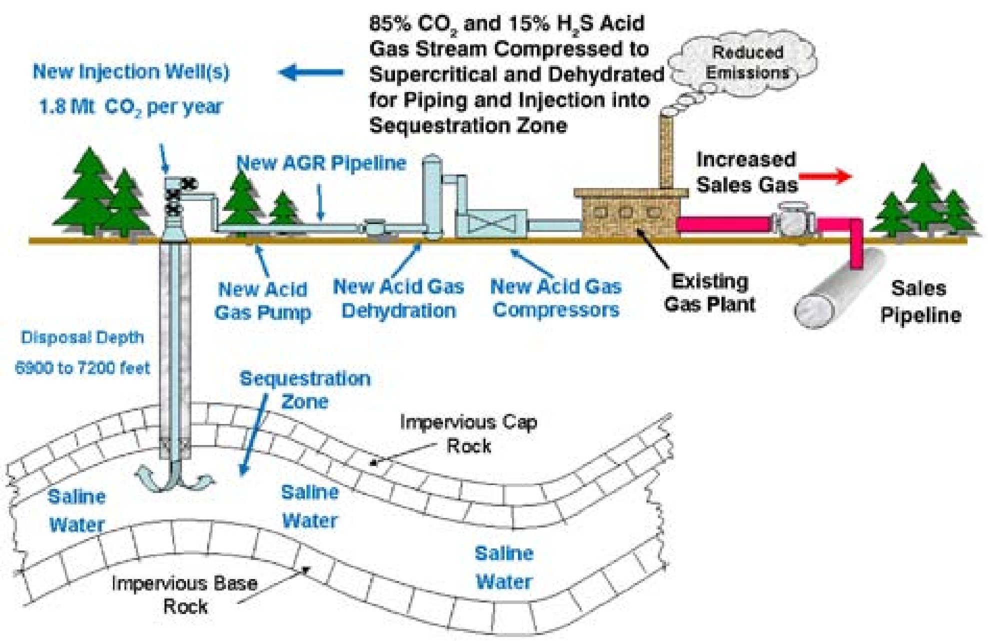
Out of the Air—Into the Soil – As part of the PCOR Partnership Validation Phase Program, Ducks Unlimited, Inc.; the U.S. Geological Survey's Northern Prairie Wildlife Research Center; and North Dakota State University are demonstrating optimal practices for sequestering CO_2 in native, restored, and cropland wetlands and surrounding grasslands at multiple sites located in the PPR. Grasslands and wetlands are being sampled throughout Montana, North and South Dakota, Minnesota, and Iowa. The project results are intended to serve as a model to promote and implement terrestrial sequestration across the PPR. PCOR Partnership is currently providing payments to landowners interested in conveying carbon rights on native grassland and expiring Conservation Reserve Program acres. The accumulated credits from numerous landowners are being transferred to a firm that specializes in marketing carbon credits, which are then sold on the open market.

CO_2 in an Unmineable Lignite Seam – CO_2 will be injected into unmineable lignite seams in northwestern North Dakota. The injected CO_2 is trapped by naturally bonding to the surfaces of the fractured lignite and also has the potential to displace methane occupying the coal fractures. In August 2007, five wells were drilled, and a series of tests were conducted on the wells. Geophysical information on the properties of the subsurface system was collected, and approximately 9 m (30 ft) of rock and coal core samples, ten of which were the primary coal seam of interest, were retrieved from one of the wells. Well development will continue through the summer of 2008, with CO_2 injection slated for early that fall. This validation test will provide valuable information regarding lignite for both CO_2 sequestration and enhanced coalbed methane production.

Development Phase Commercial-Scale Demonstrations

Williston Basin Demonstration

The cost-effective separation of CO_2 from flue gases is a major barrier to the widespread implementation of geologic sequestration at conventional power plants and other large-scale stationary sources of CO_2. The Williston Basin Demonstration will be one of the first large-scale CCS projects utilizing CO_2 from a retrofitted conventional coal-fired power plant. A portion of the flue gas output of Basin Electric Power Cooperative's Antelope Valley Station will be processed to capture its CO_2. This CO_2 will then be dehydrated, compressed to supercritical conditions, and transported about 150 miles (220 km) via pipeline to the sequestration site. The project will benefit economically by utilizing some of the existing compression and pipeline assets at the adjacent Great Plains Synfuels Plant. Once at the sequestration site, the CO_2 will be injected at a depth of nearly 2 miles (approximately 10,000 ft or 3,000 m) into the pore space of an oil reservoir. In the pore space, the CO_2 will dissolve into the oil and allow the oil to flow more easily to the production wells. At the end of economical oil production, most of the purchased CO_2 will remain permanently trapped in the underground reservoir. The demonstration will emplace nearly 1 million metric tons (1.1 million tons) of CO_2 a year. The characterization of the Williston Basin in western North Dakota indicates there are several billion metric tons of additional storage capacity in these types of geologic settings. The primary objective of the PCOR Partnership Development Phase Williston Basin Demonstration is to verify and validate the concept of utilizing the Region's large number of oil fields for large-scale injection of anthropogenic CO_2 for the purposes of EOR leading to permanent CO_2 storage.



Western Canadian Basin Demonstration

Most geologic sequestration projects are designed to emplace CO_2 into an underground geologic structure, referred to as a trap, which may have previously contained oil or natural gas for millions of years. However, another type of geologic setting, known as a deep brine reservoir, is believed to offer even greater potential for CO_2 storage because of its regionally extensive nature. The Western Canadian Basin Demonstration will be one of the first commercial-scale geologic sequestration projects to emplace CO_2 into a North American brine reservoir. To accomplish this, over 1 million metric tons (1.1 million tons) of CO_2 (85% CO_2, 15% H_2S) produced at an existing gas-processing facility in northeastern British Columbia, Canada, will be compressed to a supercritical state—CO_2 gas will be put under high pressure so that it behaves like a fluid; the pressure is similar to the conditions in the underground geologic injection zone—before being transported via pipeline, approximately 3 miles (5 km) to an injection site. Once at the injection site, the CO_2 will be sent into the ground to a depth of approximately 6,500 ft (2,000 m). There the supercritical CO_2 will be injected into the carbonate rocks (limestone and dolomite) of the Elk Point Group rock formations and dissolve into the highly saline water that fills the pores of the Elk Point Group rocks. Once the CO_2 enters the pores of the carbonate rocks, the naturally high pressure and temperature conditions in the Elk Point Group will maintain the CO_2 in the supercritical state permanently. The injection zone in Elk Point is capped by a substantial shale layer that provides a very competent seal. Other geologic layers, including the thick shales of the Banff Formation, act as seals in the thousands of feet of rock between the top of the Elk Point Group and the base of the zone of drinkable groundwater. Characterization of the geology of the Region has shown many suitable sites for CO_2 storage and capacities exceeding several million metric tons of CO_2 per square mile.

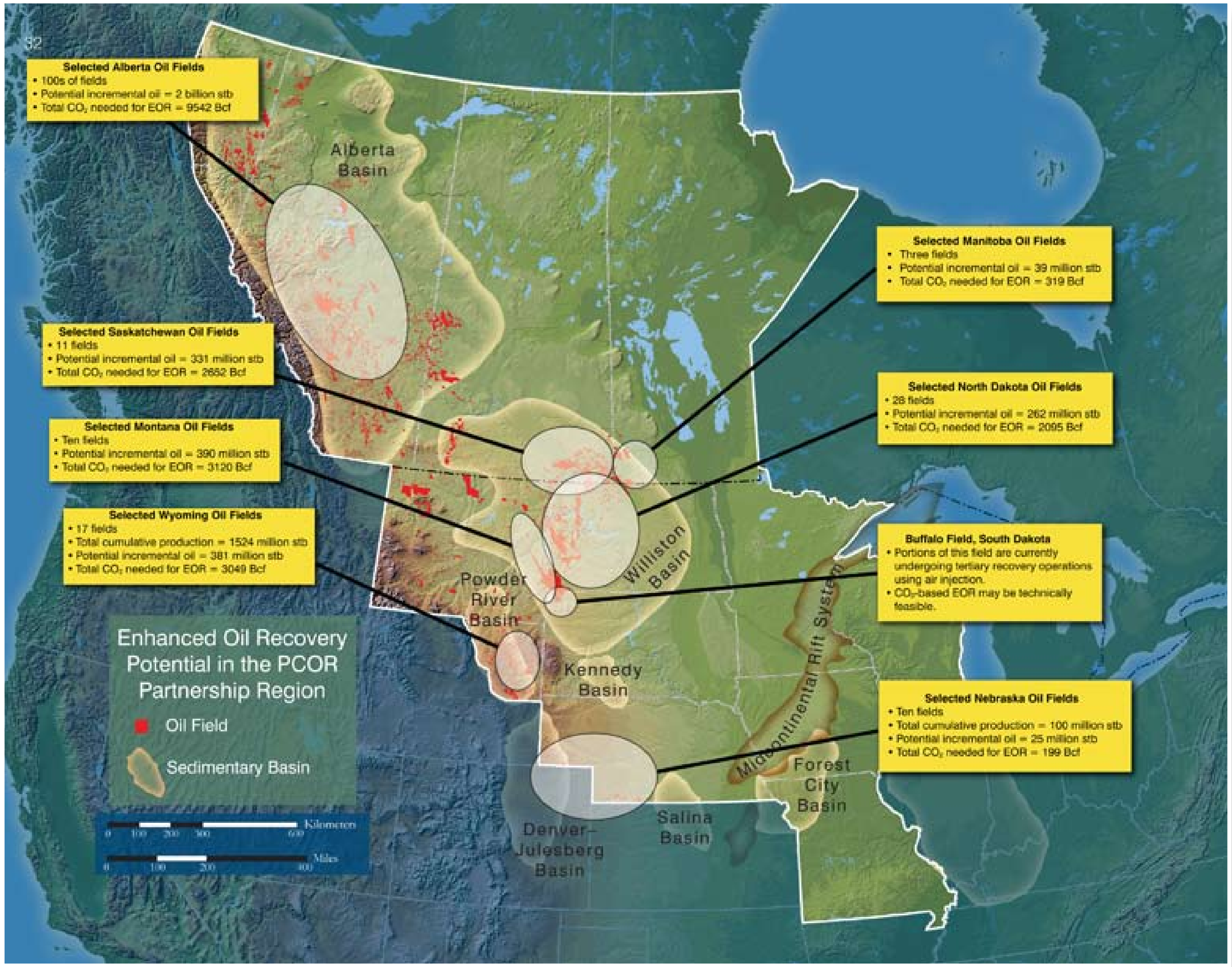
The PCOR Partnership Region is rich in agricultural lands, forests, and wetlands that hold tremendous potential for terrestrial sequestration. The Prairie Pothole Region, which stretches from northwestern Iowa, across the Dakotas, and into Saskatchewan and Alberta, holds promise as an area for terrestrial CO_2 storage. The PCOR Partnership and Ducks Unlimited, Inc., recently announced the creation of a major carbon offset program. The goal of the program is to secure native and planted grasslands, reduce negative impacts on duck and other wildlife habitats, and ensure that existing soil carbon will not be exposed to the atmosphere, helping to mitigate the effects of climate change.

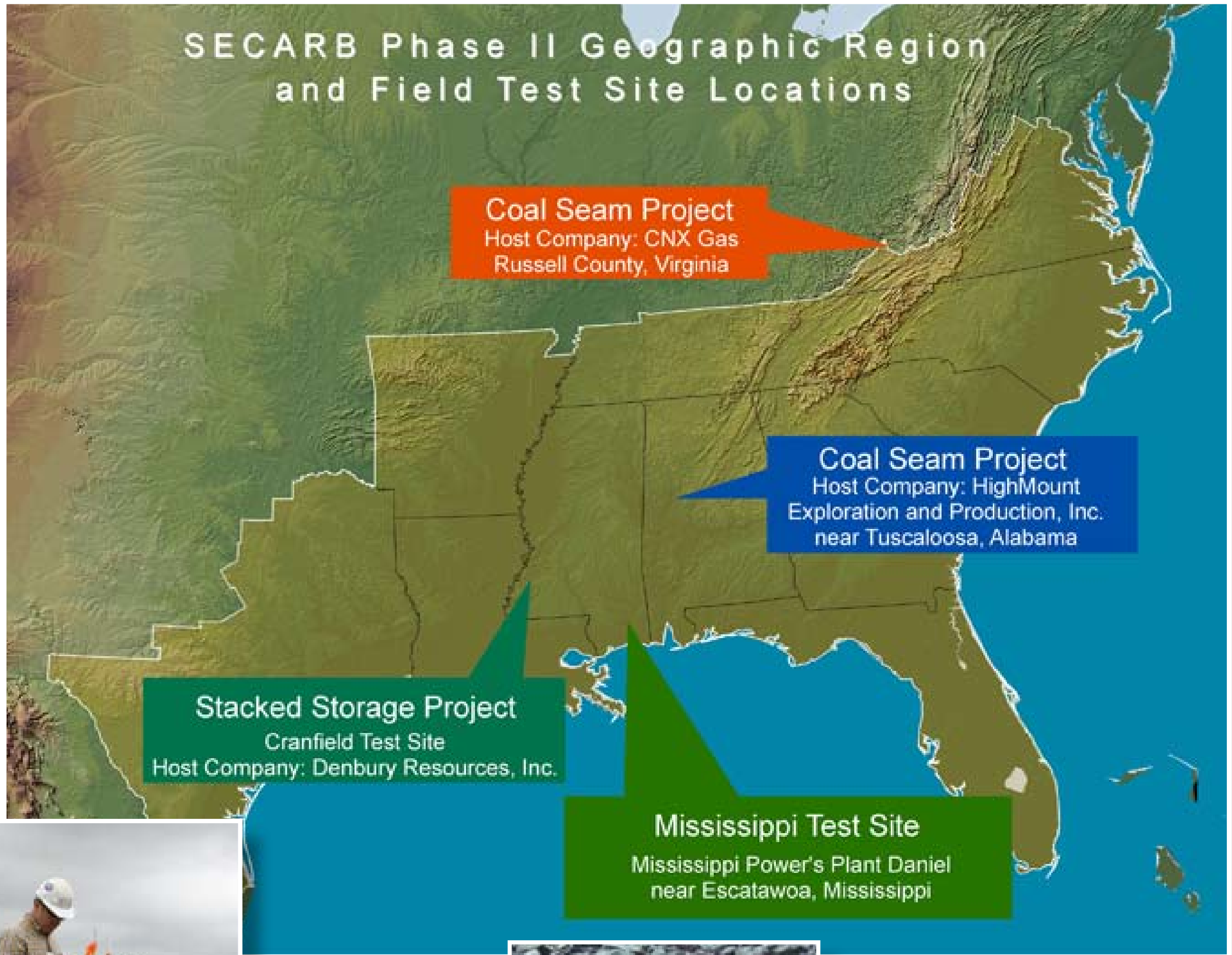
Many of the geologic formations deep beneath a wide area of the Region hold great potential to sequester CO_2. The western half of the Region contains numerous mature oil fields that are well suited for EOR through the injection of CO_2. Enhanced oil recovery has been identified as a means not only to store CO_2 emissions but also to manage CO_2 as a potential value-added product. In an example of a regional government initiative, the province of Alberta recently announced a $2 billion fund to advance projects that include CO_2 capture and EOR.

Aside from the EOR aspect, several areas of the PCOR Partnership Region overlie stacked sequences of prime geologic sequestration targets in saline formations. The arrangement of multiple target zones in close proximity to multiple CO_2 sources enables optimum sequestration potential with minimal transportation constraints. In some cases, key infrastructure is already in place. Examples include the well-known Weyburn sequestration project and the associated CO_2 capture and pipeline infrastructure operated by the Dakota Gasification Company.

Proactive industries in the Region have recently initiated additional capture and sequestration activities. These include Basin Electric's plan to capture over 1 million metric tons (1.1 million tons) of CO_2 annually from the Antelope Valley Station in North Dakota, as well as several others.

Early commercialization opportunities will be realized in meeting existing unmet CO_2 demand for EOR purposes. The potential to recover over 0.5 billion m^3 (3 billion barrels) of incremental oil through EOR will be a strong driver in the commercialization of capture and transportation efforts in the PCOR Partnership Region.





Coal seam.

Drill core and drill chip logging from site characterization at the Mississippi Power test site. Courtesy of Southern Company and ARI.

Mississippi Power Company's Plant Daniel.

Southeast Regional Carbon Sequestration Partnership

The Southeast Regional Carbon Sequestration Partnership (SECARB), led by the Southern States Energy Board (SSEB), represents the 11 southeastern states of Alabama, Arkansas, Florida, Georgia, Louisiana, Mississippi, North Carolina, South Carolina, Tennessee, Texas, and Virginia. Additionally Kentucky and West Virginia are collaborating with the Appalachian Coal Seam Project.

SECARB is accomplishing its objectives by conducting four field validation studies in the Region's most promising geologic formations: (1) validating injectivity, capacity and containment; (2) advancing the state of the art in monitoring, measurement and verification techniques and instrumentation; (3) further characterizing geologic formations in the Southeast for future readiness; (4) identifying and addressing issues for sequestration technology deployment; and (5) fostering local, regional, and national public involvement and education programs. The field tests include the following:

- Two Coal Seam Projects for validation of sequestration opportunities in the Black Warrior Basin and the Central Appalachian Basin where CO_2 ECBM recovery operations can add economic value and where unmineable coal seams can provide sequestration opportunities.

- The Mississippi Test Site focuses on validating geologic storage in a deep, saline formation. The test is being conducted at Mississippi Power Company's Victor J. Daniel, Jr. coal-fired power plant near Escatawpa, Mississippi.

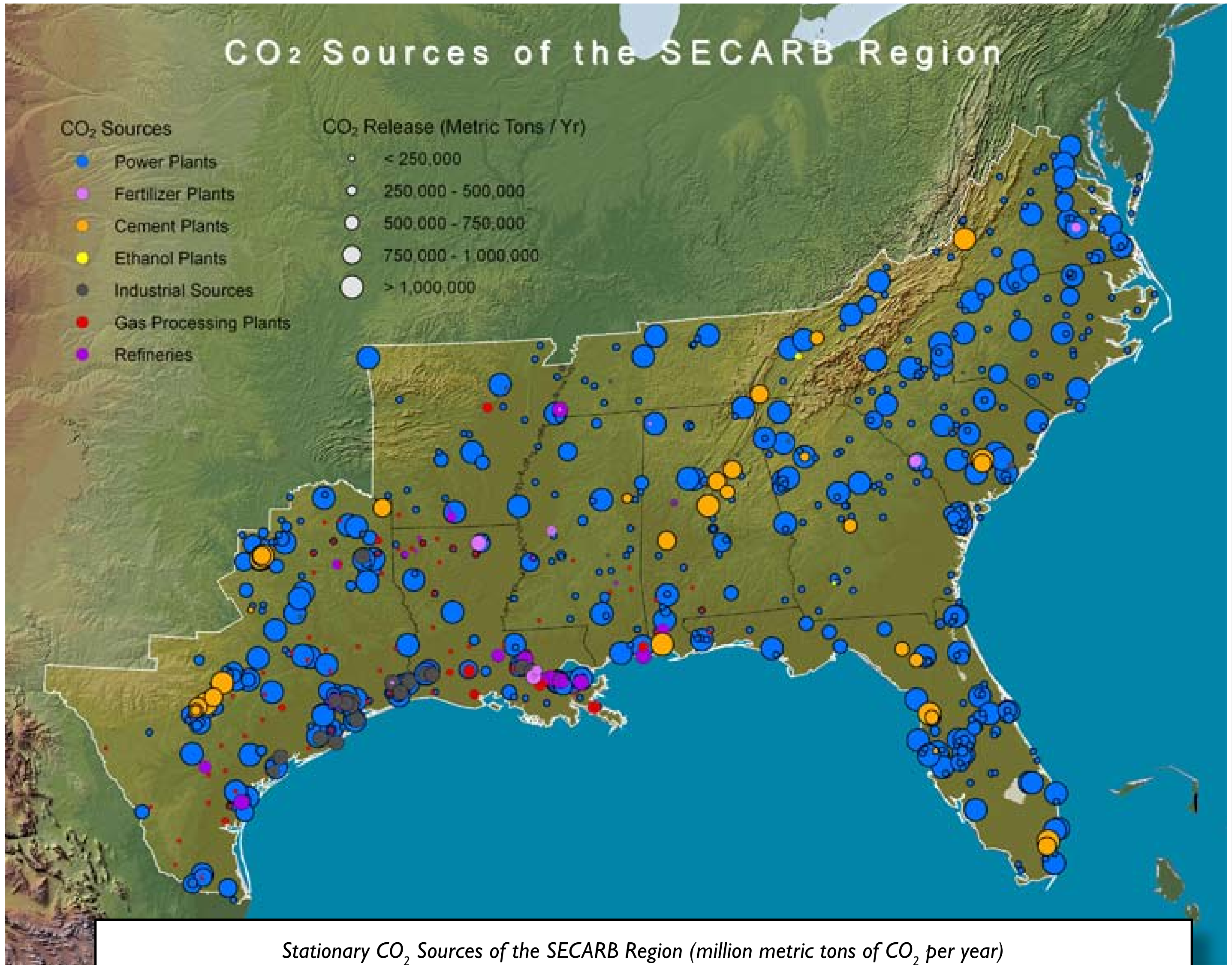
- The Gulf Coast Stacked Storage Project in Cranfield, Mississippi, builds upon the Gulf Coast Carbon Center of the University of Texas Bureau of Economic Geology (UT BEG) experience managing the Frio Basin Project. The field test investigates a stacked sequence of hydrocarbon and brine reservoir intervals, where EOR with CO_2 can serve as an economic driver in establishing the CO_2 infrastructure for transportation and storage into underlying deep saline formations.

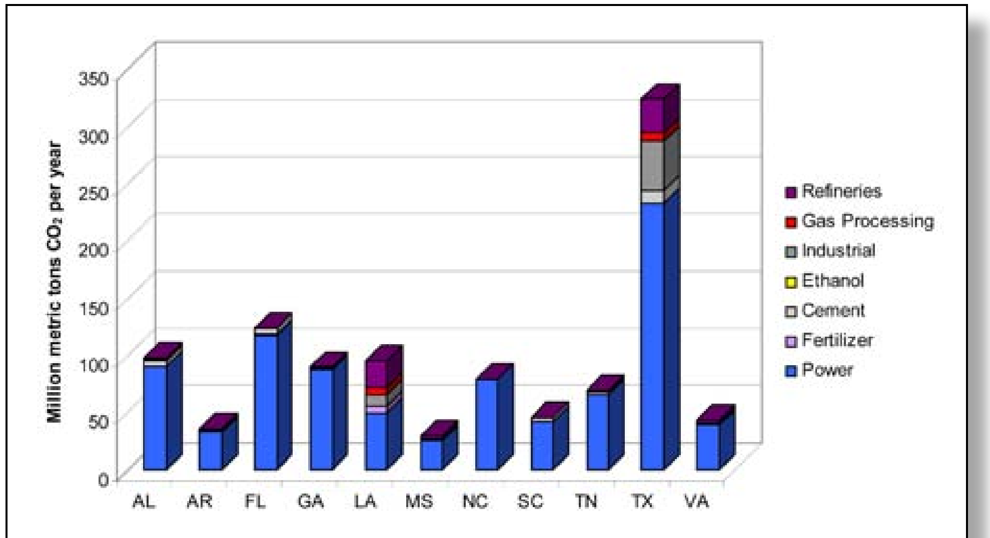
The primary goal of the SECARB Partnership is to develop the necessary framework and infrastructure, conduct field tests of carbon sequestration technologies, and evaluate options and potential opportunities for carbon sequestration in the Region.

SECARB CO_2 Sources

There are more than 900 large, stationary sources of CO_2 in the SECARB Region which are potential targets for carbon sequestration. Their total annual emissions are estimated at just over 1 billion metric tons (1.2 billion tons) of CO_2. Fossil-fuel (coal, oil, and gas) power plants are the largest contributors, accounting for approximately 83 percent of the total CO_2 emissions (see graph).

The SECARB Region is also host to a number of non-power related stationary sources of CO_2. These include, in descending order of contribution of CO_2: refineries, ethylene plants, cement plants, gas processing plants, iron and steel plants, and ethylene oxide plants.





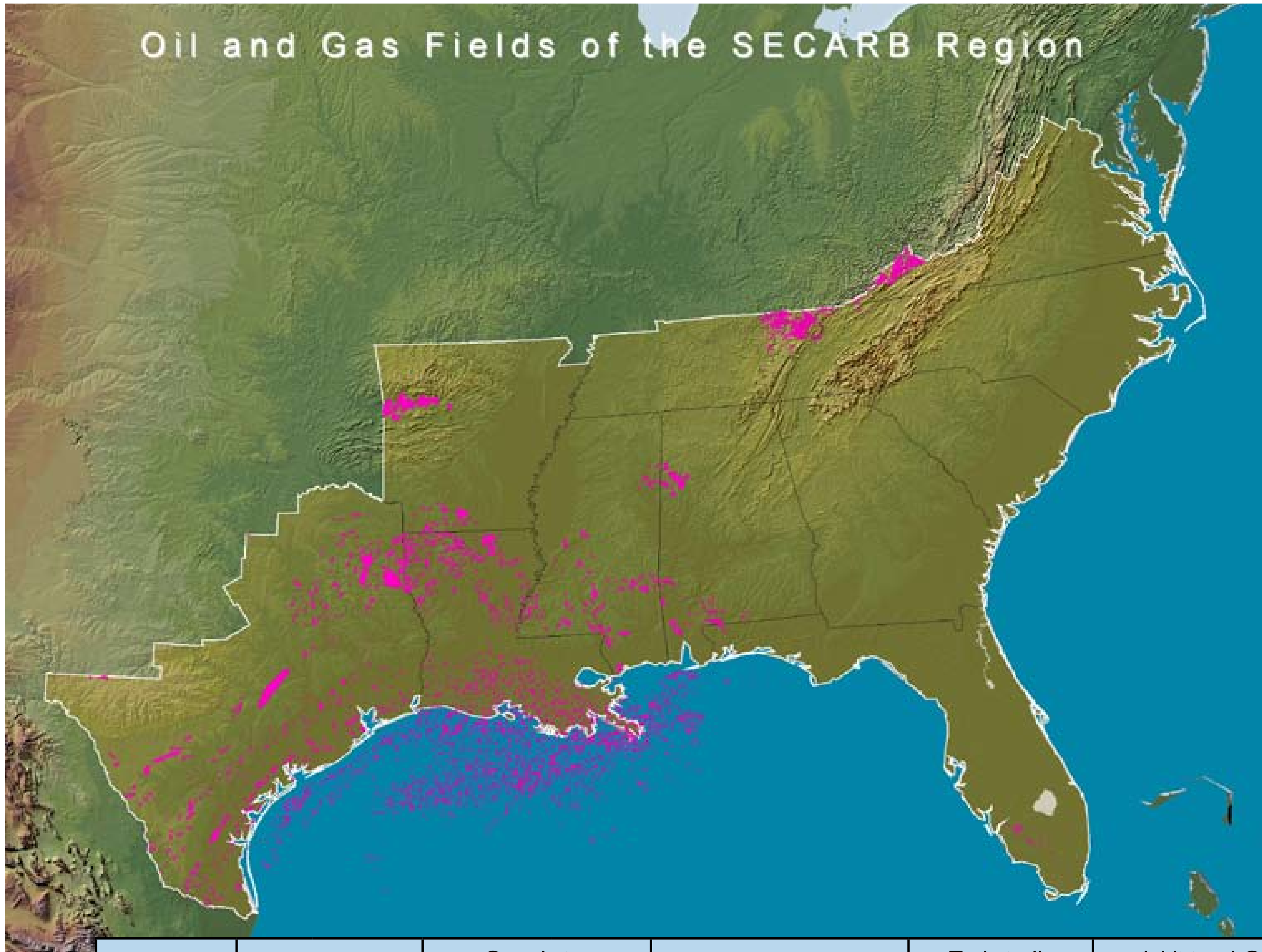
CO_2 emissions for the SECARB Region are displayed in the chart (right) and map (above) by location, source type, and quantity.

Scherer Coal fired power plant in Juliet, Georgia produces over 25.6 million tons of CO_2. per year. (Source: Georgia Power)

Stationary CO_2 Sources of the SECARB Region (million metric tons of CO_2 per year)

State	Electric Generation*	Fertilizer*	Cement Plants *	Ethanol*	Industrial*	Petroleum/ Natural Gas*	Refineries/ Chemical*	Total*
AL	71.1	0.2	5.4	—	0.5	0.3	1.3	78.8
AR	32.9	—	0.9	—	0.3	0.5	0.8	35.4
FL	137.0	—	5.5	—	0.1	0.1	—	142.7
GA	88.0	0.9	1.0	—	0.1	—	—	90.0
LA	52.6	4.6	0.8	—	9.6	5.9	28.3	101.8
MS	28.3	0.6	0.5	—	0.1	0.8	3.6	33.9
NC	76.7	—	—	—	0.1	—	—	76.8
SC	36.1	—	3.8	—	0.4	—	—	40.3
TN	61.8	—	1.5	0.4	0.2	—	1.8	65.7
TX**	237.6	—	11.1	—	42.5	4.8	37.2	333.2
VA	44.6	0.7	1.1	—	0.2	—	—	46.6
TOTAL	866.7	7.0	31.6	0.4	54.1	12.4	73.0	1045.2

* Units are all in million metric tons
** Eastern Texas: TRRC Districts 1-6



SECARB Oil and Gas Reservoirs

The SECARB Region has a rich history of oil and gas production, particularly in the Gulf Coast states of Louisiana, Mississippi, and eastern Texas. As such, considerable information exists about the geologic settings and reservoir properties of these potential CO_2 storage sites.

The Region has produced nearly 7 billion m^3 (44 billion barrels) of oil and nearly 9.4 trillion m^3 (332 trillion ft^3) of natural gas. Application of CO_2 EOR could add 3.9 billion m^3 (24 billion barrels) of oil to these totals. These oil and gas reservoirs provide opportunities for storing CO_2, assuming that the saline water occupying the pore space can be efficiently displaced with injected CO_2.

The CO_2 storage resource offered by the oil and gas fields in the SECARB Region is nearly 31 billion metric tons (34 billion tons). These oil and gas fields can provide excellent sites for securely storing CO_2, given the presence of a porous and permeable reservoir overlain by a competent seal. Thus, the SECARB Region offers the potential for integrated application of CO_2 EOR and CO_2 sequestration, accelerating the storage of CO_2 in the Region.

Left: Well at theCranfield Test Site. Courtesy of BEG, UT Austin.

Below: CO_2 injection well, Cranfield Test Site Courtesy of BEG, UT Austin.

	Number of Fields		Cumulative Conventional Recovery		Conventional CO_2 Storage Resource		Technically Recoverable Oil CO_2-EOR	Additional CO_2 Storage Resource* CO_2-EOR	
	Total	Assessed	Oil Million Bbls	Gas Bcf	Million Metric Tons	Bcf	Million Bbls	Million Metric Tons	Bcf
Alabama	133	63	622	1,856	344	6,504	216	46	864
Florida	23	8	556	<1	109	2,061	348	74	1,392
Mississippi	110	101	1,346	5,300	399	7,549	851	180	3,404
Louisiana	964	331	11,847	117,697	6,781	128,153	5,573	1,179	22,292
Arkansas	42	42	1,394	1,415	250	4,728	577	122	2,308
Virginia	49	49	—	89	10	180	—	—	—
Tennessee	213	213	—	—	—	—	—	—	—
LA Federal Offshore	1,337	1,001	15,843	176,466	17,754	335,550	5,227	1,106	20,908
East Texas**	678	678	12,510	29,373	4,005	75,695	10,995	2,327	43,980
TOTAL	3,549	2,486	44,118	332,196	29,652	560,420	23,787	5,034	95,148

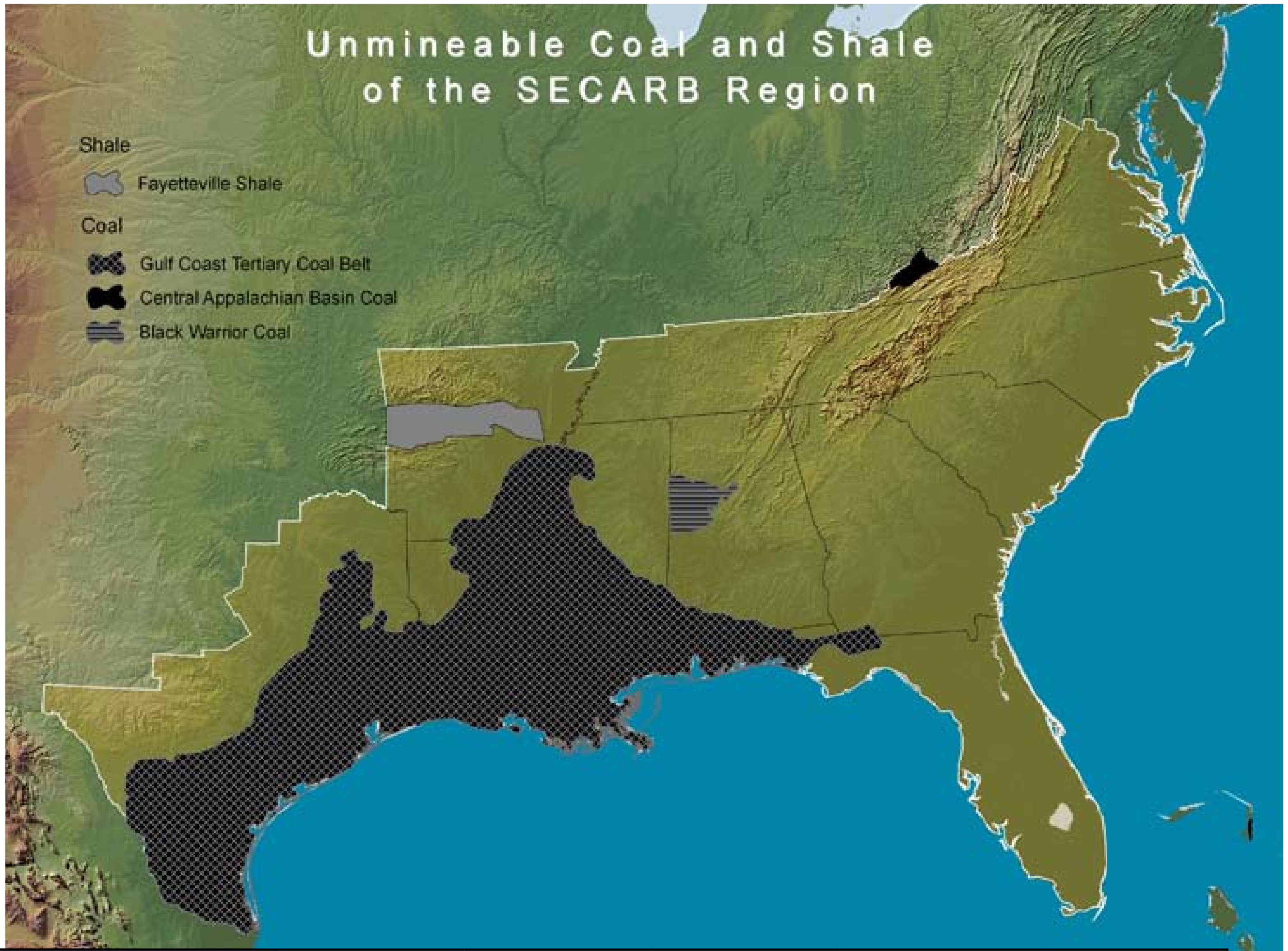
* Additional CO_2 storage resource calculated by using 4,000 cf of CO_2 storage per barrel of technically recoverable CO_2-EOR oil
**TRRC Districts 1-6

SECARB Coal Seams and Gas Shales

Three significant coal basins and one gas shale basin have been appraised within the SECARB Region. The first of the coal basins, the Virginia portion of the Central Appalachian Basin, may have the CO_2 storage resource for 308 to 818 million metric tons (340 to 902 million tons) of CO_2. The Black Warrior Basin in Alabama and Mississippi has potential CO_2 storage resource of 0.9 to 1.3 billion metric tons (1.0 to 1.4 billion tons) of CO_2. The third coal basin, the areally extensive Gulf Coast Tertiary Coal Belt, may hold from 43 to 60 billion metric tons (47 to 66 billion tons) of CO_2. Additional information is needed to more rigorously quantify this large potential CO_2 storage option.

There is one gas shale basin in this Region appraised to date, the Fayetteville Shale in the Arkoma Basin of Arkansas and Oklahoma. This shale is estimated to have a of CO_2 storage resource of 14 to 20 billion metric tons (15 to 22 billion tons).

Considerable uncertainty surrounds the effective utilization of the large, potential CO_2 storage resource offered by coal seams and gas shales, particularly with respect to CO_2 injectivity and injection well requirements. The two SECARB field tests, in the Central Appalachian and the Black Warrior basins, will help reduce this uncertainty.

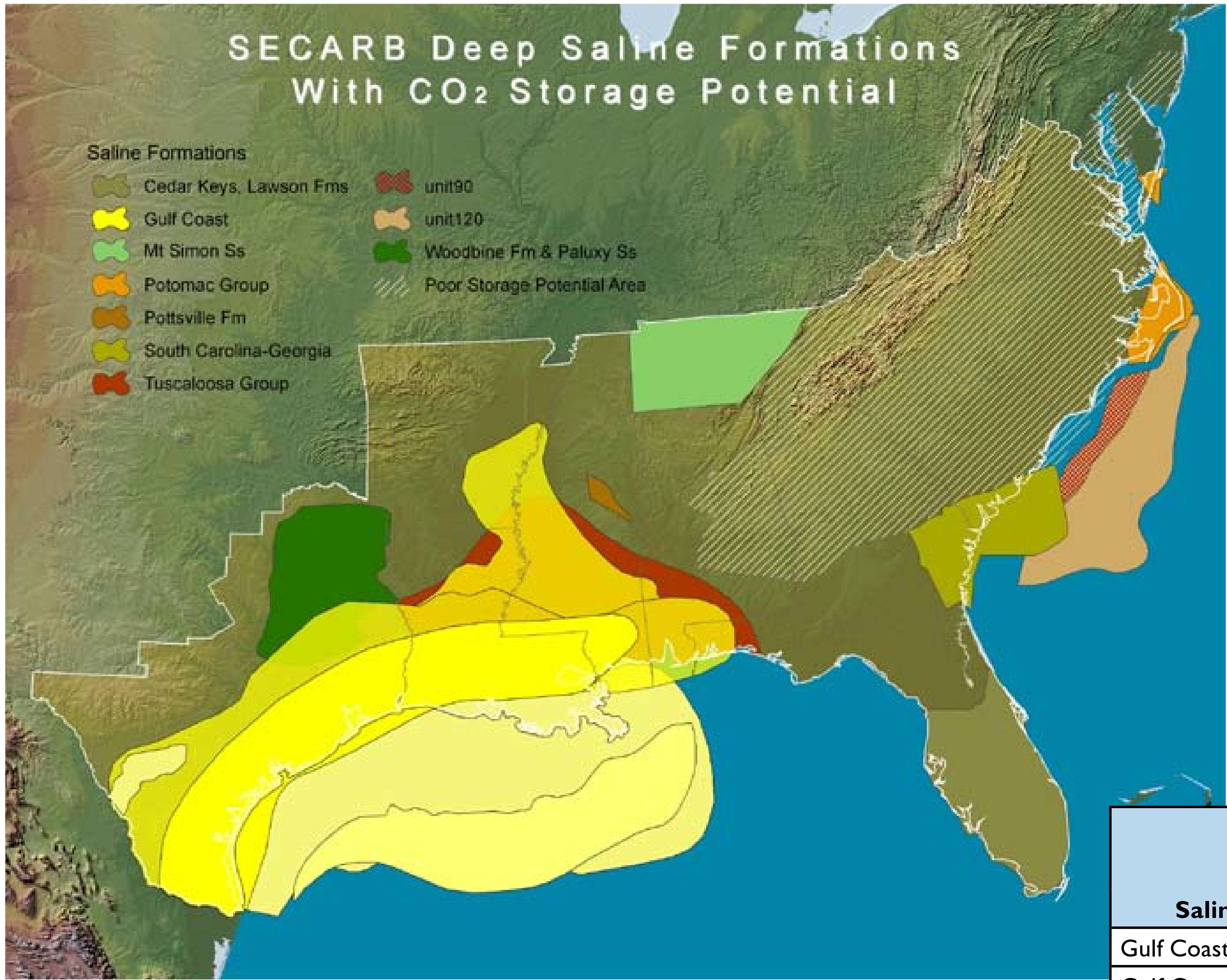


Above: Coal Train (Source: Governor of Indiana).

Right: CO_2 storage resource in unmineable coal seams for the SECARB region

Basin	State	Status of Development	Area (square miles)	CO_2 Storage Resource			
				Trillion Cubic Feet (Tcf)		Billion Metric Tons	
				High Estimate	Low Estimate	High Estimate	Low Estimate
COAL							
Central Appalachian	Virginia	Mature	1,269	15	6	0.8	0.3
Black Warrior	Alabama	Mature	4,389	24	17	1.3	0.9
Gulf Coast Tertiary Coal Belt	East Texas*	Undeveloped	71,277	505	354	27	19
	Louisiana	Undeveloped	40,501	299	209	16	11
	Mississippi	Undeveloped	28,195	195	137	10	7
	Arkansas	Undeveloped	7,829	57	40	3	2
	Florida	Undeveloped	6,100	46	32	2	2
	Alabama	Undeveloped	5,915	46	32	2	2
	Georgia	Undeveloped	501	—	—	—	—
		Subtotal	**160,318**	**1,148**	**804**	**60**	**43**
		TOTAL Coal	**165,976**	**1,187**	**827**	**63**	**44**
SHALE							
Arkoma (Fayetteville)	Arkansas	Emerging	8,610	380	266	20	14

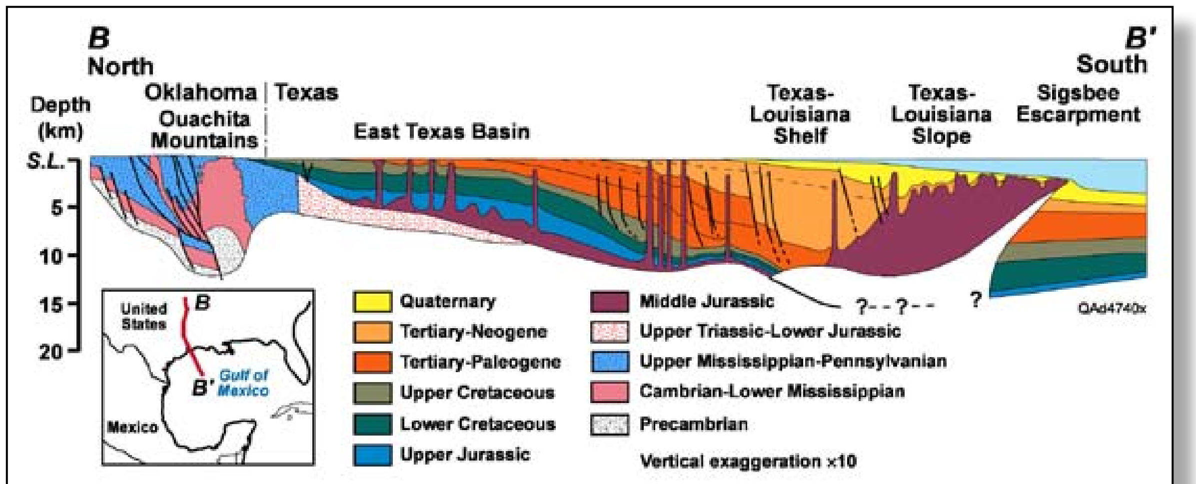
* TRRC Districts 1-6



SECARB Deep Saline Formations

Much of the capacity of the SECARB Region lies in a thick wedge of sandstones in several sub-basins rimming the Gulf Coast. Sandstones of the Upper Cretaceous Tuscaloosa Formation of Alabama, Mississippi, and Louisiana host the current SECARB field tests. Overlying Tertiary formations extend offshore, and recent reassessment of these units has quantified additional CO_2 storage resource. Other Cretaceous formations that provide significant CO_2 storage resource include sandstones in Texas, South Carolina, Georgia, the subsea bed in the Atlantic offshore of the Carolinas and Virginia, and carbonates and sandstones in Florida. Initial mapping shows areas of saline CO_2 storage resource in Mt. Simon of Tennessee and Pottsville of Mississippi; with further assessment this capacity may be increased, as well as additional CO_2 storage resource mapped in southern Georgia and Arkansas. Current assessment shows that the saline formations in the SECARB region have the potential to store 2,275 to 9,100 billion metric tons (2,500 to 10,000 billion tons) of CO_2.

The storage potential of the Appalachian Piedmont and Blue Ridge areas is poor because the dominant crystalline and metamorphic rocks in these areas provide little pore volume and offer no predictable sealing capacity.



Geologic cross-section across the Gulf Coast showing the thick wedge of Cretaceous and Tertiary age sediments that offer numerous large capacity saline formations. Source: Modified from: (1) Arbenz (1988), Plate 11, cross section D-D′ and Salvador (1991), Plate 6, cross section B-B′.

Saline Formations	State	CO_2 Storage Resource			
		Trillion Cubic Feet		Billion Metric Tons	
		High Estimate	Low Estimate	High Estimate	Low Estimate
Gulf Coast Basins (Pliocene)	Multiple states*	25,705	6,426	1,360	340
Gulf Coast Basins (Miocene)	Multiple states*	75,824	18,956	4,012	1,003
Gulf Coast Basins (Oligocene)	Multiple states*	24,884	6,221	1,317	329
Gulf Coast Basins (Eocene)	Multiple states*	29,588	7,397	1,565	391
Gulf Coast Basins (Tertiary Undivided)	Multiple states	3,225	806	171	43
Gulf Coast Basins (Olmos)	TX	84	21	4	1
Tuscaloosa Group	Multiple states	1,027	257	54	14
Woodbine and Paluxy Formations	TX	963	241	51	13
Pottsville Formation	MS	210	53	11	3
Mt. Simon Sandstone	TN	95	24	5	1
Potomac Group	Multiple states*	340	85	18	4
South Carolina-Georgia Basins	Multiple states*	597	149	32	8
Cedar Keys, Lawson Formations	FL	2,099	525	111	28
Offshore Atlantic (Unit 120)	Federal	6,733	2	356	89
Offshore Atlantic (Unit 90)	Federal	587	0.1	31	8
TOTAL		171,961	41,163	9,098	2,275

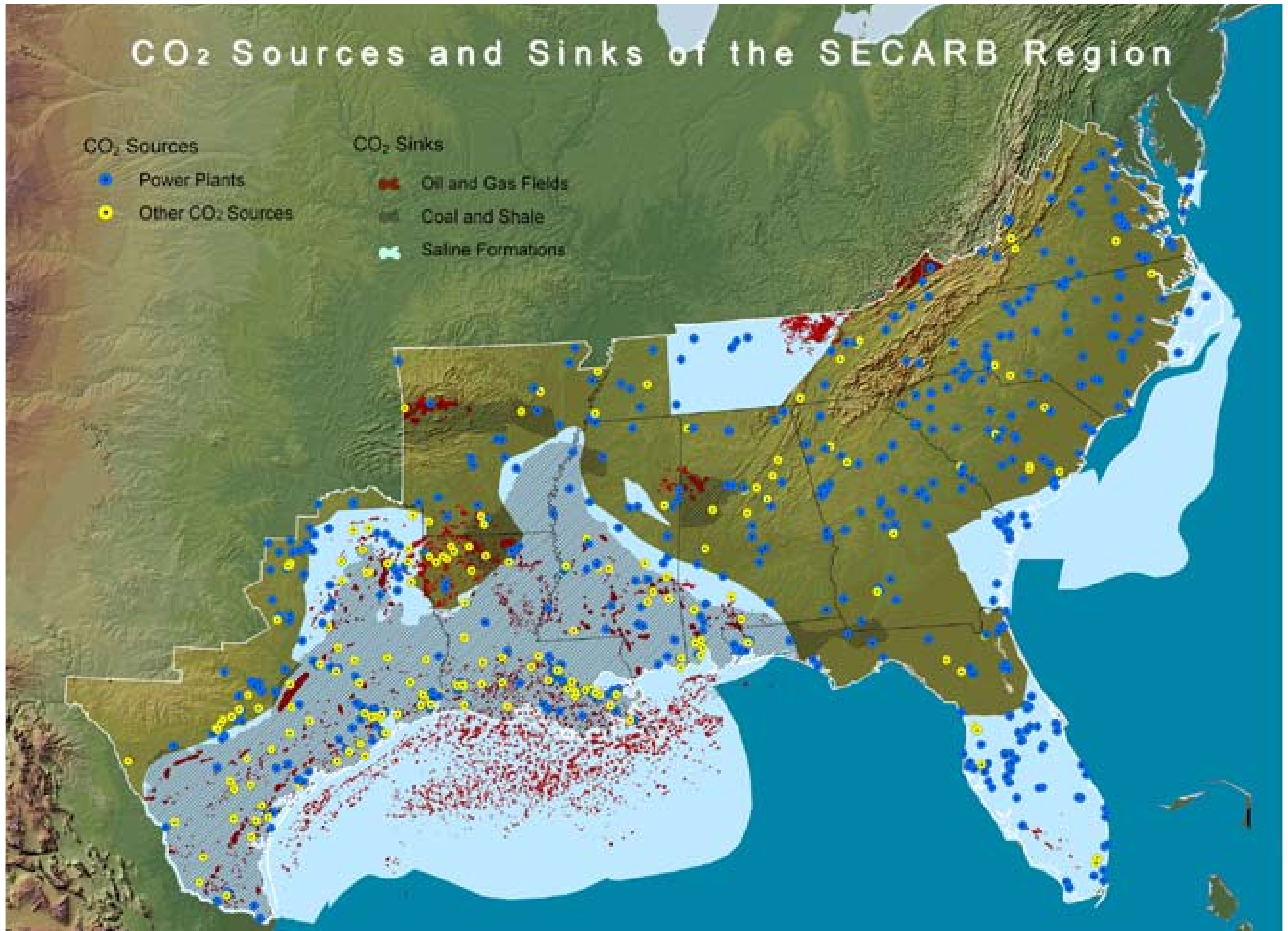
* Including offshore Federal Waters

SECARB: Composite Map of CO_2 Sources and Geologic Storage Formations

The distance between a CO_2 stationary source and a geologic storage formation is calculated as the shortest straight-line distance from each source to the nearest geologic storage site. While these results do not give a complete picture of the transportation and infrastructure requirements, they do give a first-order interpretation of the magnitude of the requirements.

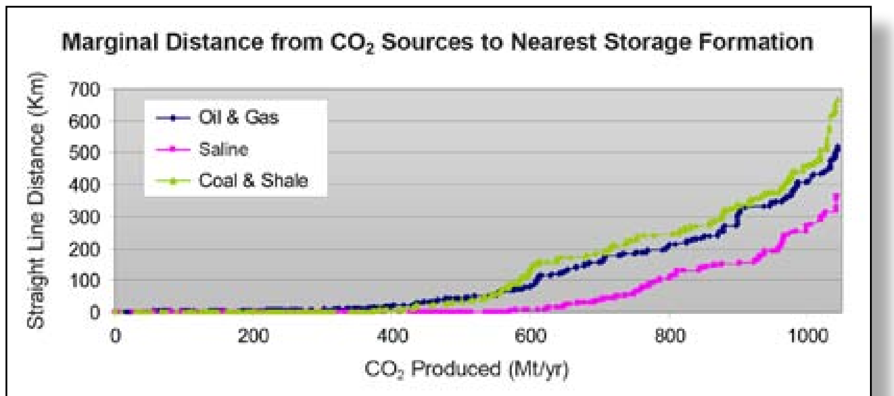
The sources in SECARB match up well with the potential storage reservoirs. For example, more than 70 percent of all sources (by volume) in the SECARB Region are located within 50 km (31 mi) of a storage formation. Approximately 40 percent of the sources are actually co-located with an appropriate storage formation. This especially occurs in the Gulf Coast region where many of the sources overlie saline formations, coal beds, or both.

The table below identifies how many years storage is possible given the current annual emissions and the known CO_2 storage resource.



Formation Type	Straight-Line Distance to Nearest Formation		
	< 50 km	50 -100 km	> 100 km
Oil and Gas Fields	50%	9%	42%
Saline Formations	71%	5%	25%
Coal and Shale	52%	4%	44%
All Reservoirs	76%	5%	19%

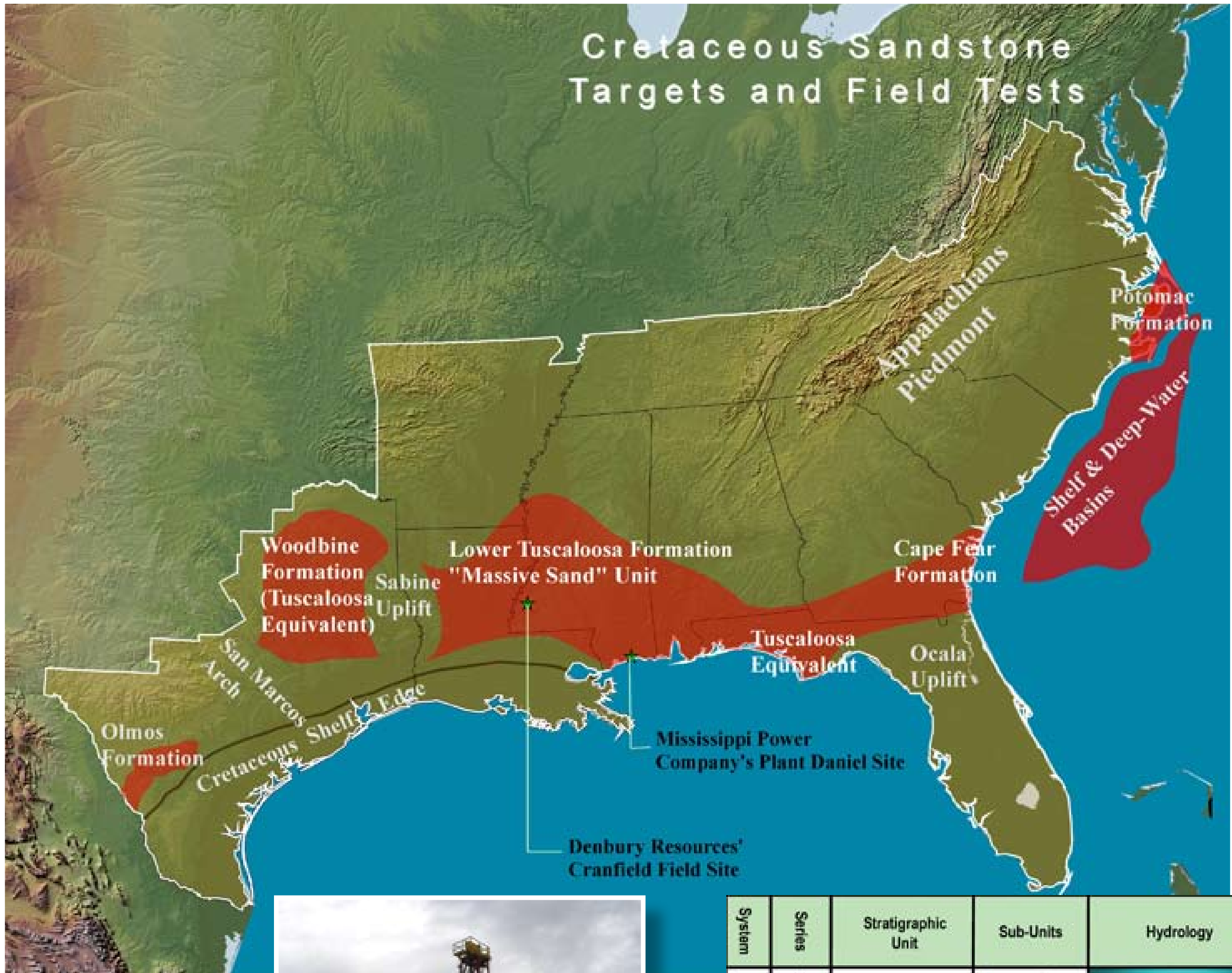
Note: The total annual CO_2 storage rate used was 938 million metric tons, which was estimated based on current emissions and assuming 90% capture efficiency.



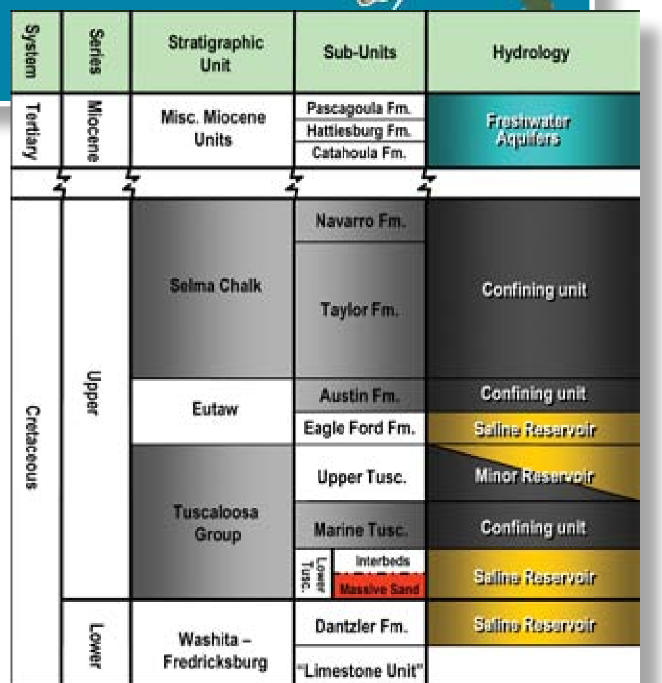
Above: Marginal distance from all CO_2 sources to their nearest storage formation.

State	CO_2 Sources (million metric tons per year)	CO_2 Storage Resource (million metric tons)				Number of Years Storage **
	Total	Oil and Gas	Coal and Shale*	Saline*	Total	
AL	79	390	2,592	32,250	35,232	446
AR	35	372	16,200	23,623	40,195	1,148
FL	143	183	1,700	28,950	30,833	216
GA	90	—	—	3,068	3,068	34
LA	102	7,960	11,100	348,744	367,804	3,606
MS	34	579	7,200	116,068	123,847	3,643
NC	77	—	—	3,380	3,380	44
SC	40	—	—	1,247	1,247	31
TN	66	—	—	1,250	1,250	19
TX****	333	6,332	18,700	513,870	538,902	1,618
VA	47	10	308	398	716	15
Federal Offshore	—	18,860	—	1,201,741	1,220,741	N/A
TOTAL	1,045	34,686	57,800	2,274,589	2,367,215	2,263***

* Low estimates used
** Years of CO_2 Storage at the current emission rates (State CO_2 storage resource/ state annual emissions)
*** Average years storage for whole of SECARB area (Total CO_2 storage resource/ total annual emissions)
**** Eastern Texas: TRRC Districts 1-6



Drilling operations at Mississippi Power's Plant Daniel. Courtesy of Southern Company and ARI.



Geological Stratigraphy Column of the Mississippi Gulf Coast (Source: Unknown)

SECARB Field Tests

SECARB will be conducting four field validation tests for geologic sequestration projects during the Validation Phase.

Stacked Storage Pilot Test - Gulf Coast Site

The Gulf Coast Stacked Storage project will demonstrate the concept of phased use of subsurface storage volume. This sequestration approach combines the early use of CO_2 for EOR followed by subsequent injection into associated saline formations. This results in both short-term and long-term benefits, as there is the immediate commercial benefit of EOR as a result of the injection of CO_2 (offsetting infrastructure development costs) followed by large-volume, long-term storage of CO_2 in brine-bearing formations. The field test is being conducted in the lower Tuscaloosa Formation in the Cranfield Unit, located in western Mississippi, at a depth of 3,140 m (10,300 ft). The monitoring program observes the pressure in the injection zone and in the overlying monitoring zone in a dedicated observation well real-time via wireline readout and satellite uplink, as well as collecting episodic changes in pressure and saturation in surrounding future producers. Injection rates in the commercial EOR flood are estimated between 91,000 and 450,000 metric tons (100,000 and 500,000 tons) per year of CO_2. The Validation Phase injection will be followed by a novel Development Phase large-volume injection into brine-bearing formations down dip of the oil ring.

Saline Formation Pilot Test—The Mississippi Test Site

Mississippi Power Company's Plant Daniel, a 2,000 MW facility near the town of Escatawpa, in Jackson County, Mississippi, is the site of the saline formation pilot test.

The Project Team has concentrated their efforts on validating the storage capacity of the "Massive" Sandstone Unit of the Lower Tuscaloosa Formation, the target saline formation beneath Plant Daniel. This regionally significant formation could hold 11–43 billion metric tons (12–47 billion tons) of CO_2, sufficient to store the CO_2 emissions from Plant Daniel and other power plants in the region for decades. Other saline formations present at depths below and above the Lower Tuscaloosa "Massive" sandstone could provide considerable additional CO_2 storage capacity in the Region.

Two new 2,900 m (9,500 ft) wells have been drilled at the site, allowing the collection of new core, geophysical logs and seismic data. This new information is being used to confirm the estimated storage capacity at the site and is being incorporated into the regional characterization of CO_2 storage resource. Injection of CO_2 is planned for the fall of 2008.

Coal Seam Pilot Test

Central Appalachian Basin

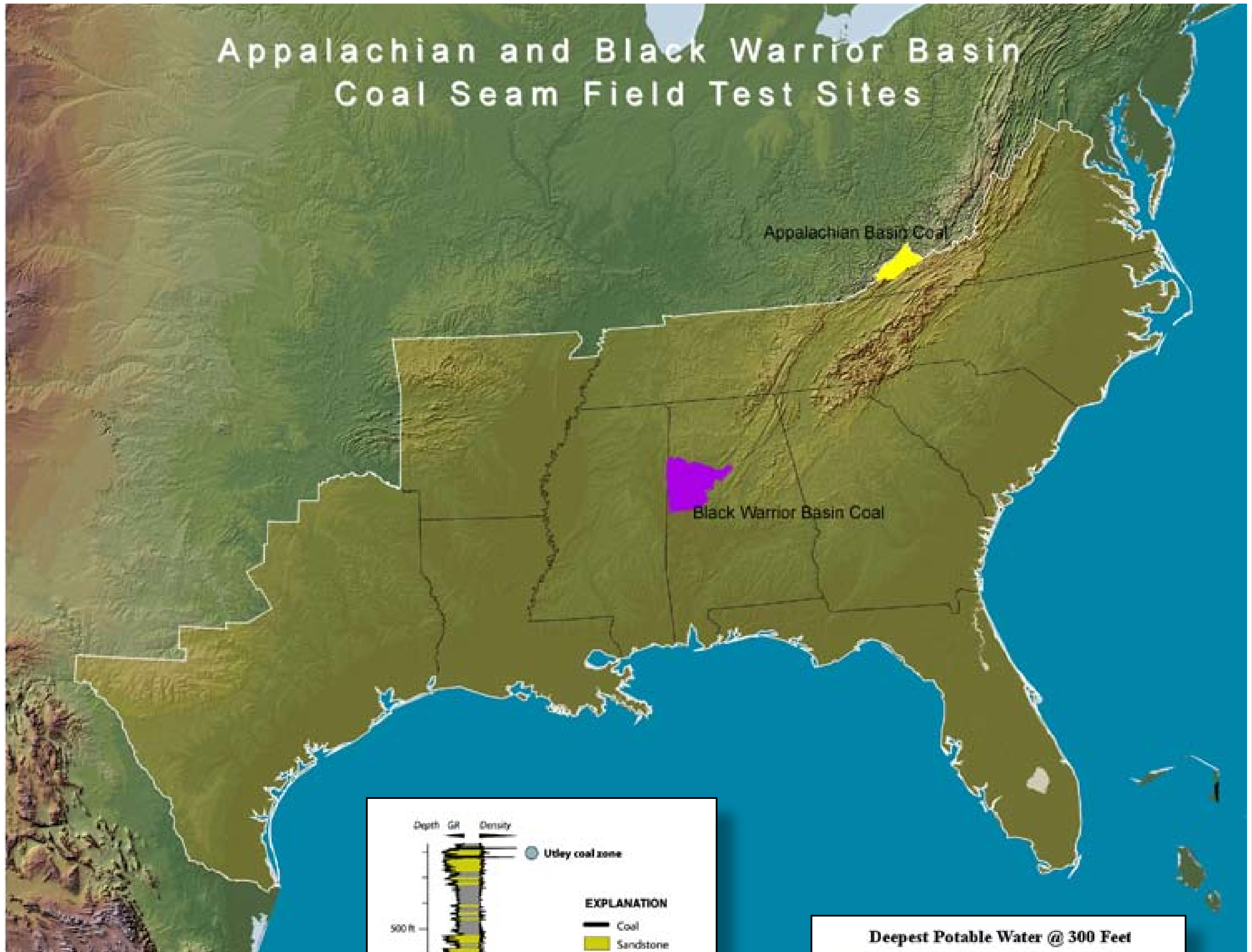
This test will validate sequestration opportunities in the Central Appalachian Basin, a northeast-to-southwest-trending basin encompassing 26,000 km^2 (10,000 mi^2) in southwestern Virginia, southern West Virginia, and southern Kentucky. The project will test the injection of 900 metric tons (1,000 tons) of CO_2 into four coal seams in the Pocahontas Formation and four coal seams in the Lee Formation at depths ranging between 490 and 670 m (1,600 and 2,200 ft). The project also includes coalbed methane recovery operations, adding economic value to the project. The primary project objective is to demonstrate geologic sequestration in unmineable Appalachian coals as a safe and permanent method to mitigate greenhouse gas emissions.

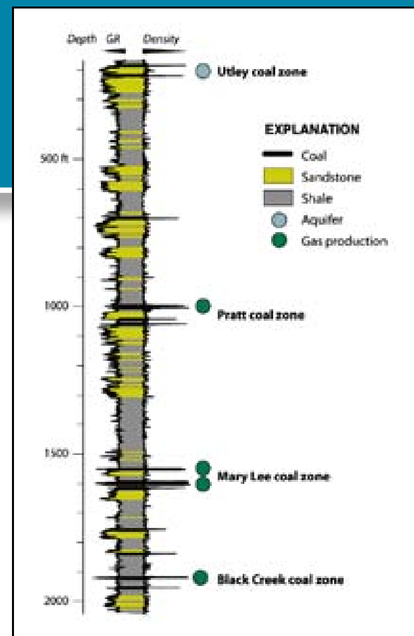
Coal Seam Pilot Test

Black Warrior Basin

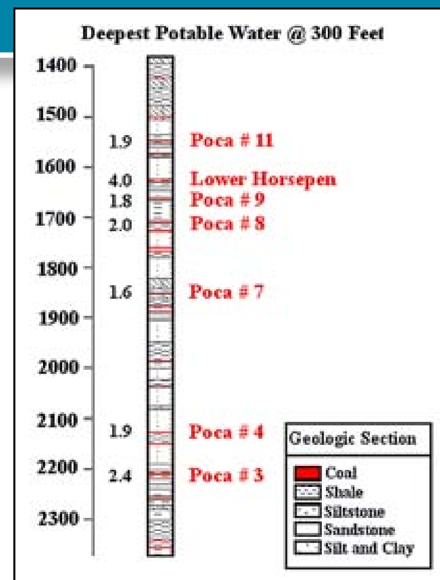
The principal objectives of the Black Warrior Basin coal seam project are to determine if sequestration of CO_2 in mature coalbed methane reservoirs is a safe and effective method to mitigate greenhouse gas emissions, and to determine if sufficient injectivity exists to efficiently drive CO_2 ECBM recovery.

This project will use CO_2 injection testing into Black Warrior basin coal seams to determine the capability of these seams to adsorb significant volumes of CO_2 for geologic carbon sequestration and ECBM recovery. The test will take place in Tuscaloosa County, Alabama, and the Black Creek, Mary Lee, and Pratt coal zones of the Pennsylvanian-age Pottsville Formation have been selected for testing. Three coal seams will be injected with 900 metric tons (1,000 tons) of CO_2 (approximately 300 metric tons [333 tons] per coal seam) at an approximate depth of 460 to 760 m (1,500 to 2,500 ft).



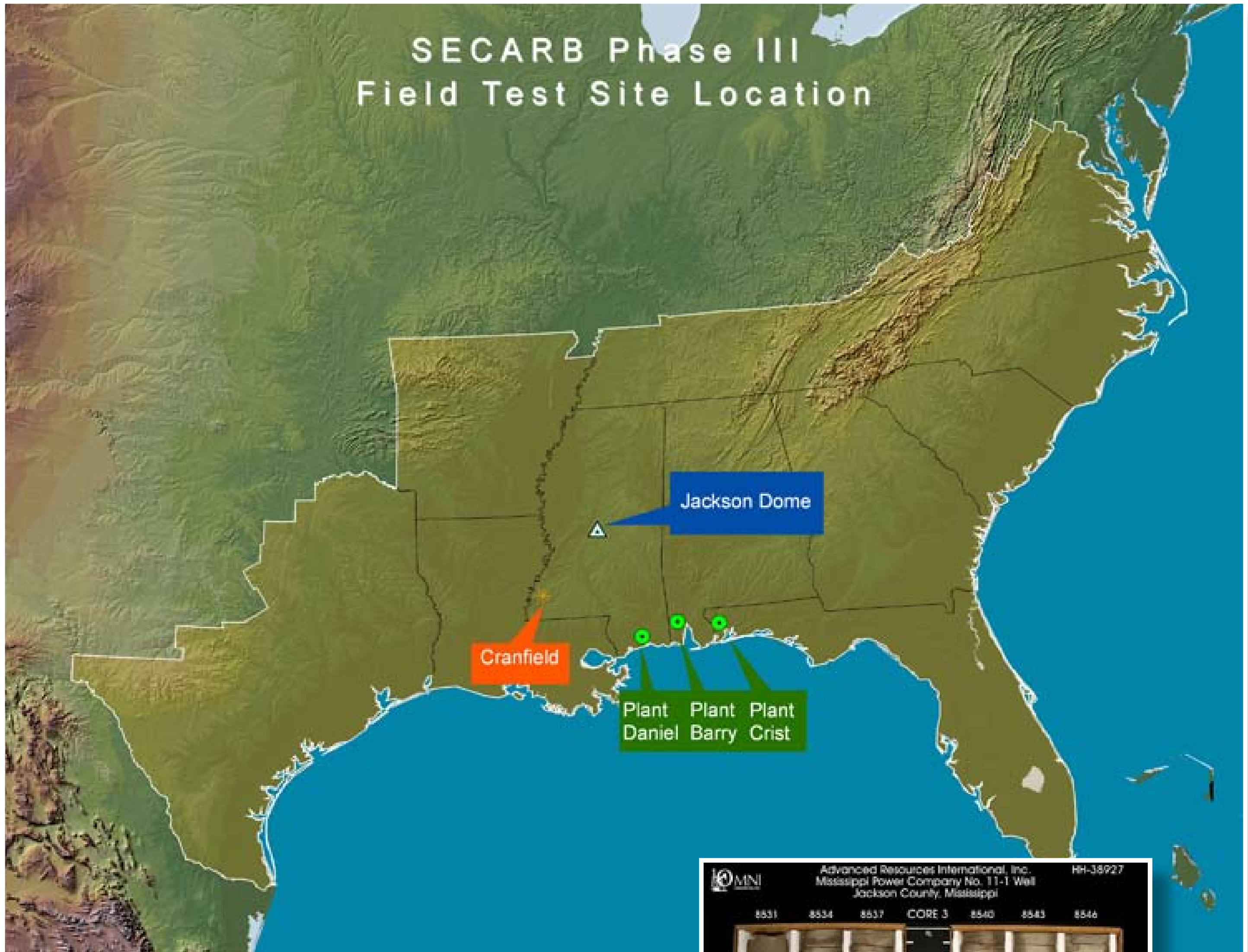


Well logs showing stacked coal, Alabama (Source: Unknown).



Stratigraphic Column from Central Appalachian Coal Beds, showing stacked coals denoted in red. (Source: Unknown).

Central App Well (actual CNX Gas well where injection will take place). Courtesy of SSEB.



CO_2-EOR production wellhead. (Courtesy of BEG, UT Austin.)

Drill core collected from Tuscaloosa Formation beneath Plant Daniel. (Courtesy of Southern Company and ARI.)

SECARB: Development Phase Project

The Development Phase program has two distinctly different components: The Early Test and the Anthropogenic Test.

- The Early Test will be conducted in the down dip "water leg" of the Cranfield Oil Field, operated by Denbury Resources, Inc. near Cranfield, Mississippi.

- The Anthropogenic Test will be conducted at or near a Southern Company plant site in the Gulf Coast region following the 2008 Field Test of saline formation storage at the Victor J. Daniel Power Plant in Mississippi.

The Tuscaloosa Formation is the main injection zone. For the Anthropogenic Test the target storage reservoir is the "Massive" sandstone, a thick, regionally extensive, porous and permeable coastal to deltaic-marine sandstone at the base of the lower Tuscaloosa. Regionally the lower Tuscaloosa is overlain by a thick section 90 to 140 m (300 to 450 feet) of shales and mudrocks that were deposed as sea level rose during marine transgression. This low permeability interval provides the major seal above the injection zone, although numerous overlying shale and chalk intervals provide redundancy in CO_2 isolation.

Injections will be at a scale sufficient to validate model predictions at high and sustained rates, adding confidence to the estimates of injectivity and capacity for future large-scale commercial sequestration. The CO_2 source for the Early Test was selected to provide high injection rates, at low cost and in the near term.

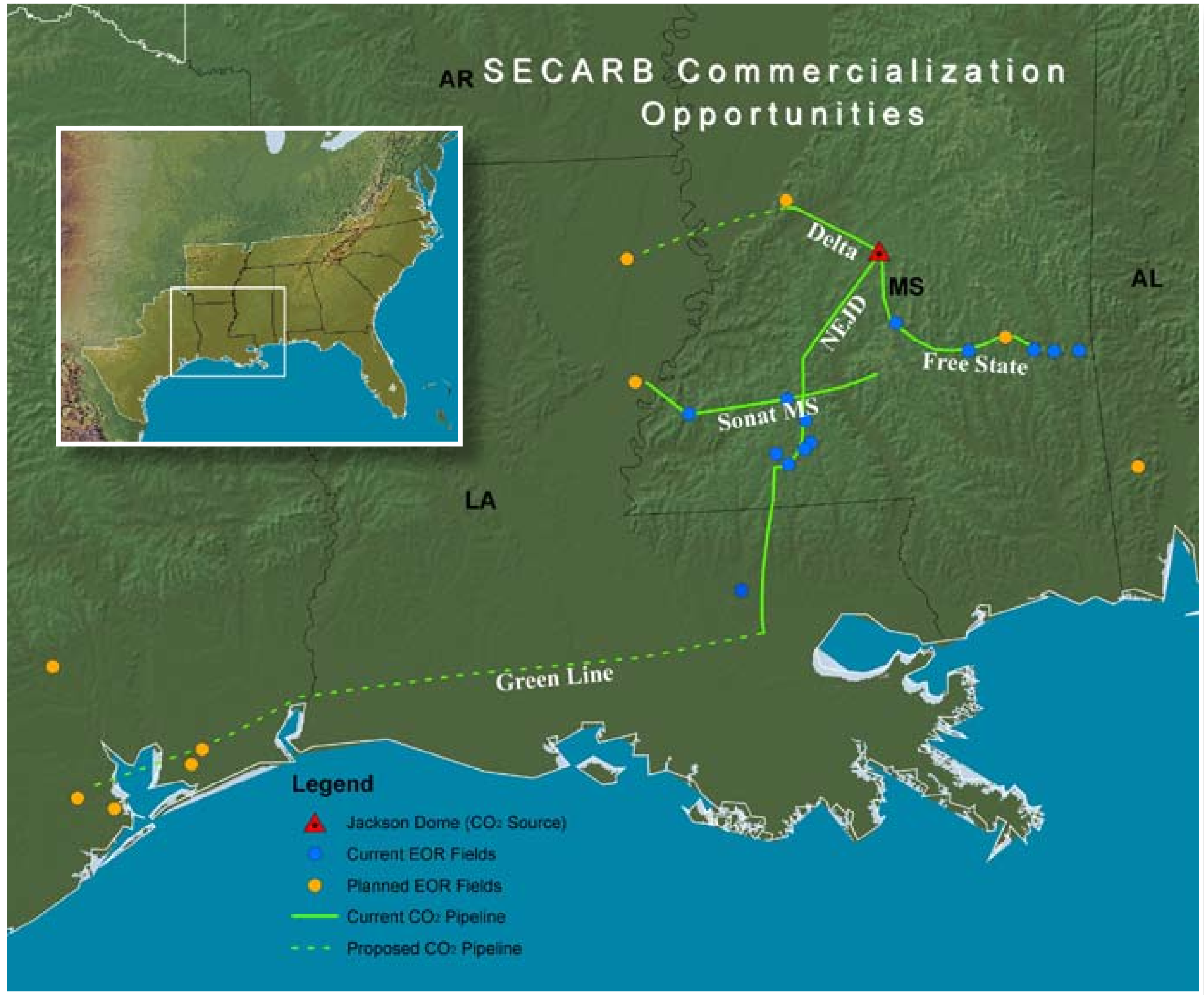
Denbury Resources will provide 0.9 million metric tons (1 million tons) of CO_2 per year from a natural source at Jackson Dome (Mississippi) via commercial pipeline. SECARB will conduct rigorous monitoring and model verification during the 10-year project with an array of multiple tools deployed at each site. Monitoring data will be collected to verify the correctness of the models in predicting plume evolution and determining the ultimate fate of the injected CO_2.

SECARB Commercialization Opportunities

Early opportunities for commercialization in the Southeast Region most likely will be associated with an ability to offset the cost of capturing and storing CO_2. Utilizing CO_2 for EOR is the primary candidate for offsetting costs in several SECARB states. Work conducted by SECARB in Gulf Coast formations will assist in expanding CO_2 EOR opportunities. Another candidate is ECBM recovery utilizing CO_2. Field tests conducted by SECARB in Central Appalachia and in the Black Warrior Basin of Alabama will assist in determining the technical and economic feasibility of ECBM.

Within the SECARB Region, EOR is in place in Mississippi. Currently, the CO_2 that is used for EOR is coming from the Jackson Dome, a natural source of CO_2 located near Jackson, Mississippi. Denbury Resources operates a pipeline network that transports Jackson Dome CO_2 to oil fields in the Southeast. The Cranfield unit, near Natchez, Mississippi, is one EOR field operated by Denbury Resources, and it is host to a SECARB Validation Phase small-scale injection as well as a Development Phase large-scale injection in the brine formation down-dip of the EOR field.

Denbury Resources is developing and expanding a CO_2 pipeline network from the Jackson Dome to potential EOR sites in Mississippi, Louisiana, Texas Gulf Coast, and Alabama. Denbury Resources also is establishing agreements with sources of CO_2 that can supplement the volumes of CO_2 produced at Jackson Dome. As a result, the Denbury Resources pipeline system has the potential for becoming the regional backbone of an integrated network for CO_2.



Regional Incentives

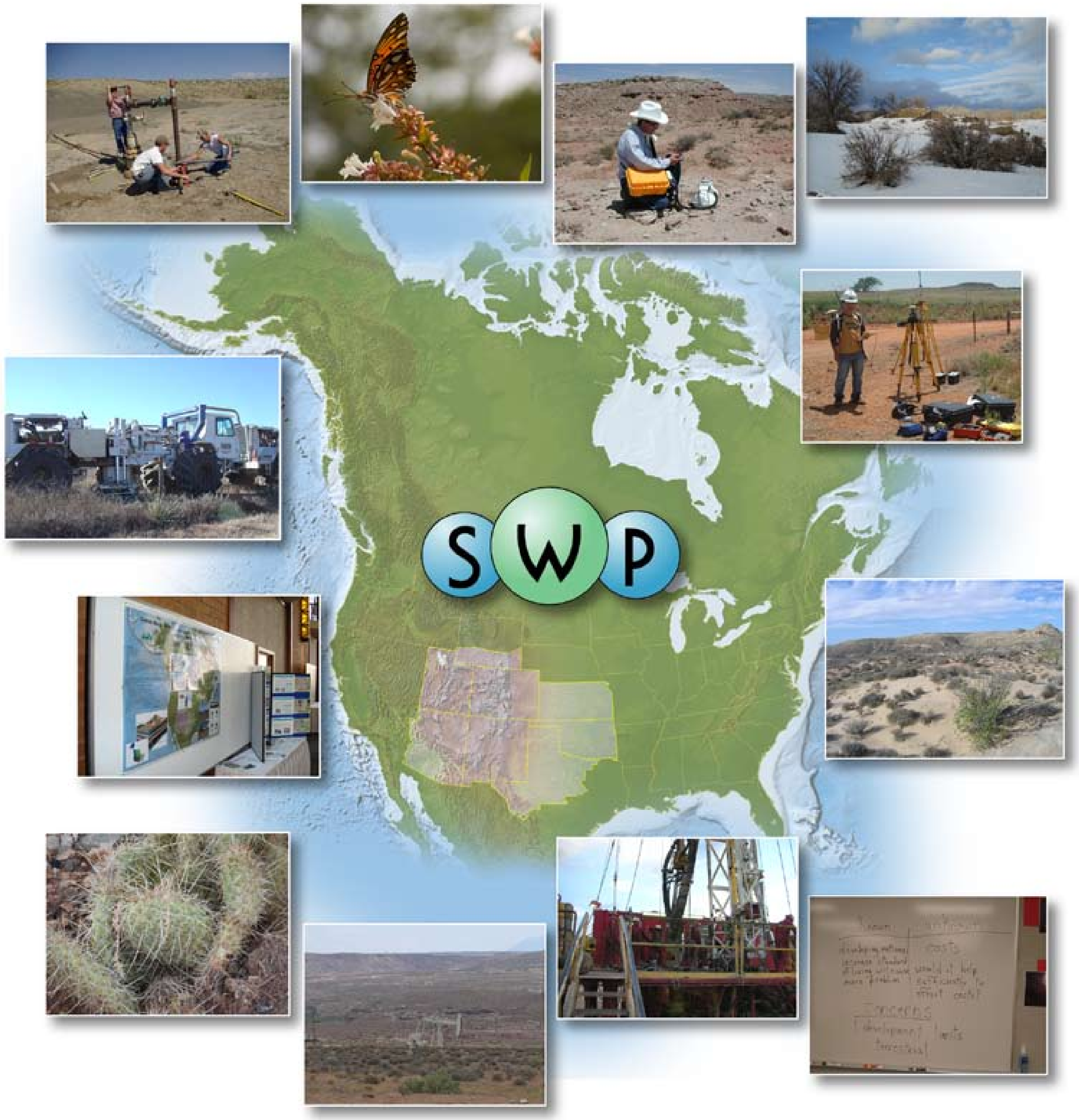
Two initiatives in the SECARB region will help advance carbon capture and sequestration deployment:

- As part of SECARB Validation Phase field investigation, Virginia Tech, Marshall Miller & Associates (MM&A), and the Geological Survey of Alabama are evaluating the feasibility of capturing CO_2 from an industrial source and storing it in unmineable coal seams and associated brine formations in Central Appalachia and the Black Warrior Basin.

- As part of SECARB Development Phase field investigation, the Electric Power Research Institute (EPRI) and Southern Company (with operating units in Mississippi, Alabama, Georgia, and Florida) currently are evaluating CO_2 capture and separation technologies. SECARB plans to inject 100,000–250,000 metric tons (110,000–280,000 tons) per year of anthropogenic (power plant) CO_2 from 2011 to 2014.

Pipeline (Source: Denbury Resources).

Current EOR Fields	Location	Proposed EOR Fields	Location
Lockhart Crossing	LA	Tinsley Field	MS
Little Creek	MS	Lake St. John Field	LA
Mallalieu	MS	Heidelberg Field	MS
McComb	MS	Delhi Field	LA
Brookhaven	MS	Citronelle Field	AL
Eucutta	MS	Oyster Bayou	TX
Soso	MS	Fig Ridge	TX
Martinville	MS	Gillock Fields	TX
Yellow Creek	MS	Hastings Field	TX
Cyprus Creek	MS	Conroe Oil Field	TX
Smithdale	MS		
Lazy Creek	MS		
Cranfield Field	MS		



Southwest Regional Partnership on Carbon Sequestration

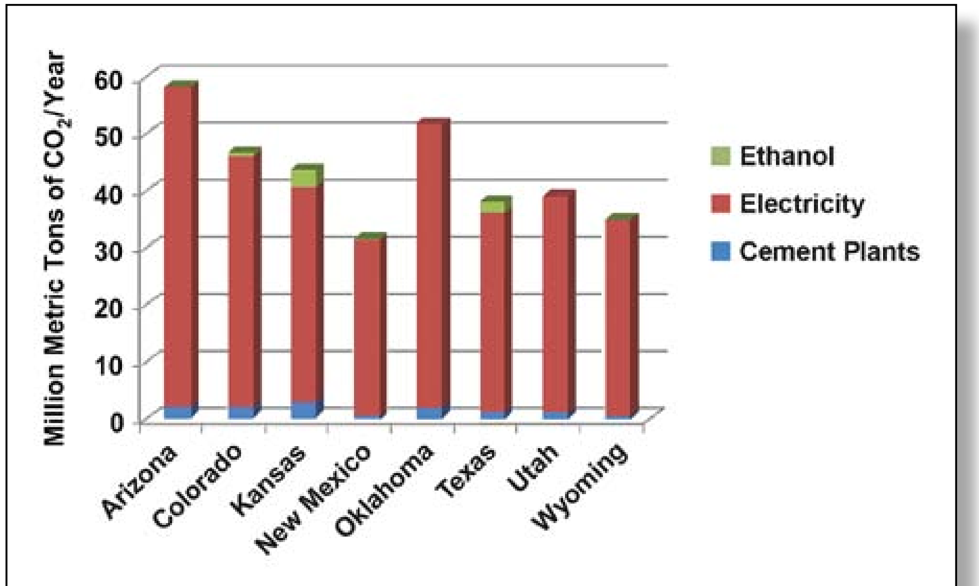
The Southwest Regional Partnership on Carbon Sequestration (SWP) was created to advance early commercial opportunities for the use of CCS systems, which are compatible with most existing energy infrastructures, and therefore have potential to be a least-cost option to mitigate CO_2 emissions contributing to global climate change. A growing body of governments, corporations, and public-private partnerships support CCS deployment, which has been endorsed by the international scientific community and a number of environmental non-governmental organizations (NGOs). Furthermore, an increasing number of companies recognize CCS as a potentially profitable line of business.

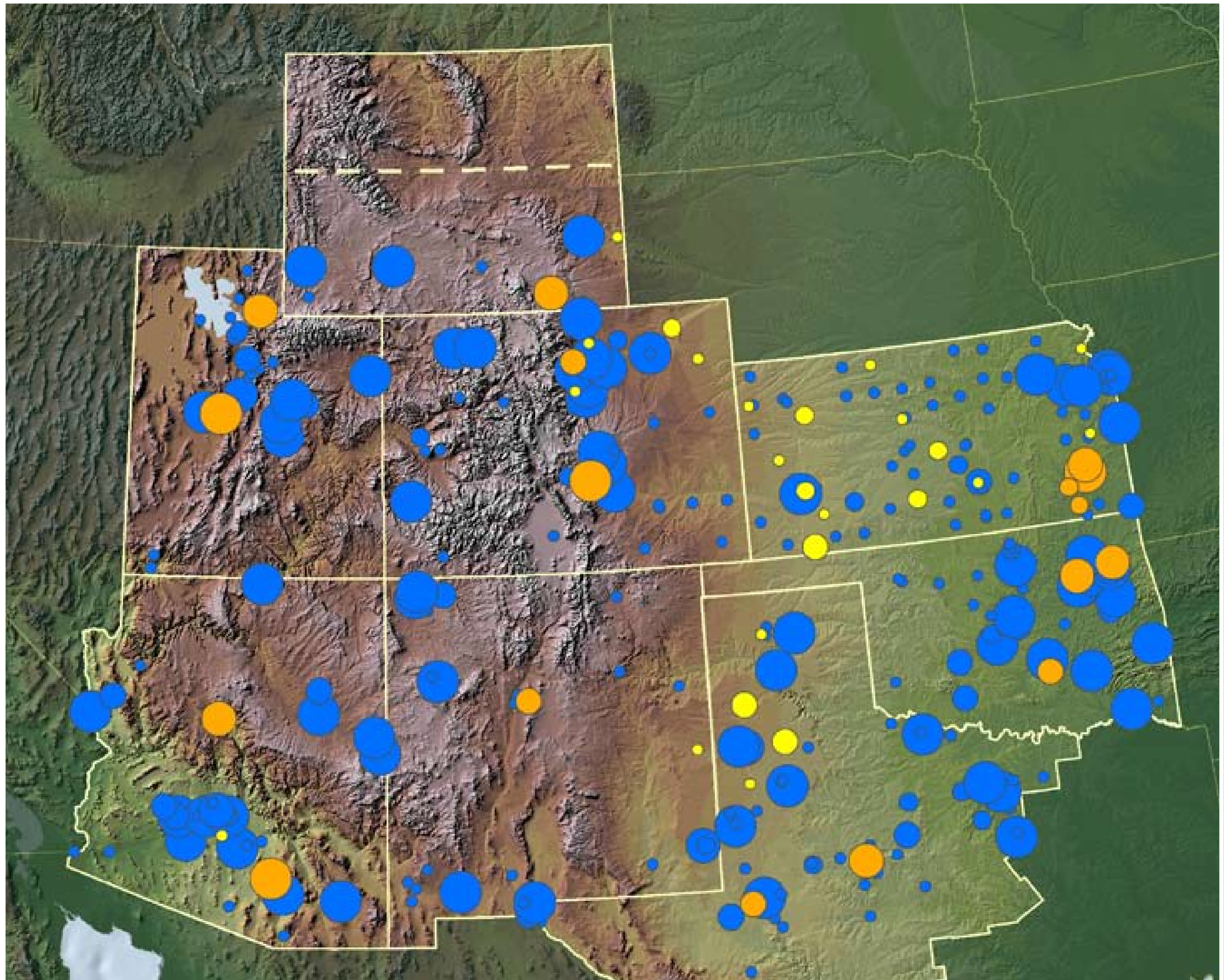
SWP is composed of a diverse group of experts in geology, engineering, economics, public policy, and outreach. These groups use their expertise to assess sequestration technologies to capture carbon emissions, identify and evaluate appropriate storage locations, and engage a variety of stakeholders in order to increase awareness of carbon sequestration. Stakeholders in this project are made up of private industry, NGOs, the general public, and government entities. There are a total of 44 current organizations represented in the Partnership including electric utilities, oil and gas companies, state governments, universities, NGOs, and tribal nations.

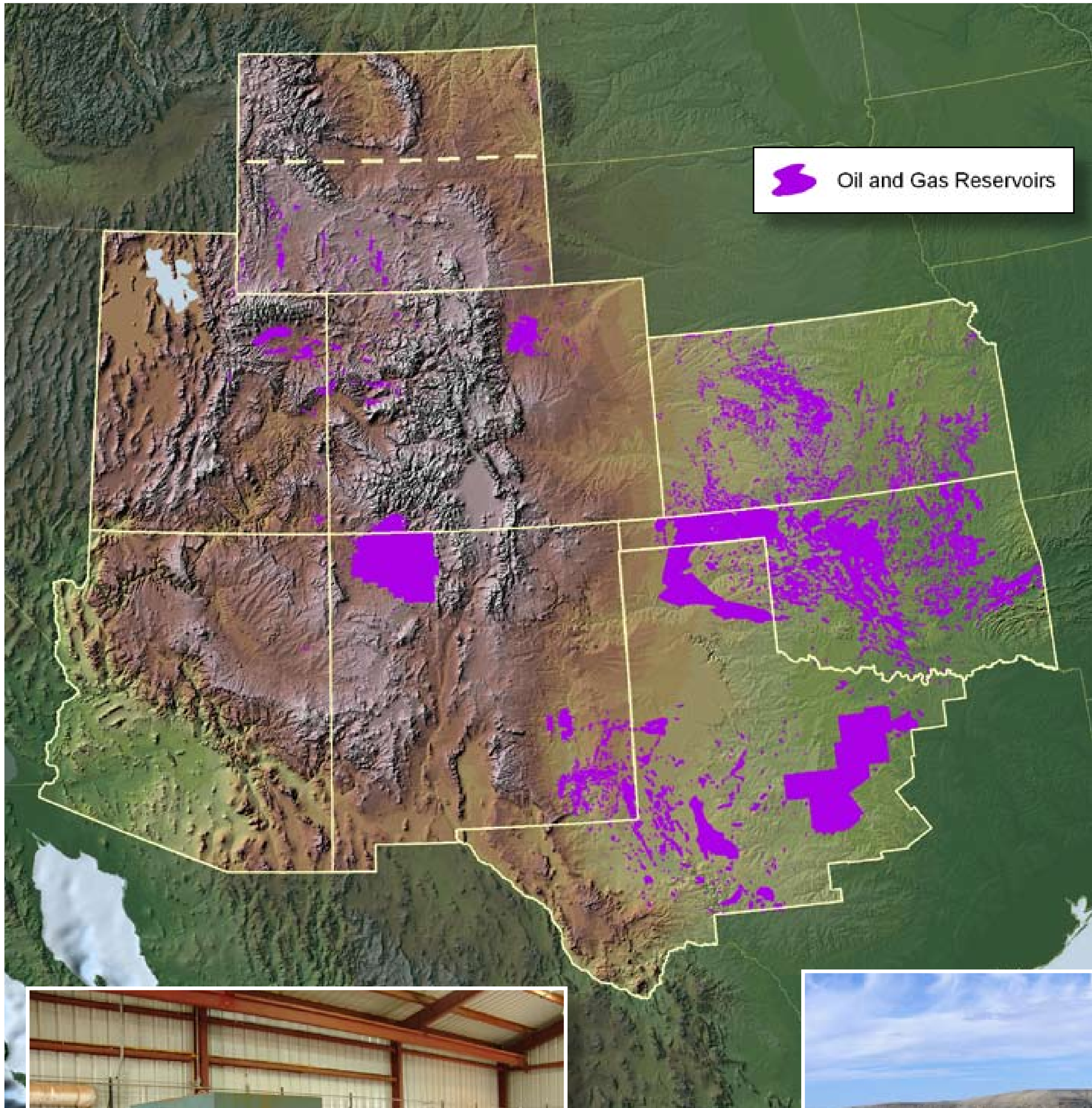
The SWP is coordinated by New Mexico Tech and encompasses New Mexico, Arizona, Colorado, Oklahoma, Utah, and portions of Kansas, Nevada, Texas, and Wyoming. Field test sites for the region are located in New Mexico (San Juan Basin), Utah (Paradox Basin and Farnham Dome), and Texas (Permian Basin).

SWP CO_2 Sources

The SWP Region is energy-rich and possesses one of the largest population and energy-production growth rates in the Nation. Two major CO_2 pipeline networks transport more than 27 million metric tons (30 million tons) per year of natural, subsurface CO_2 from southern Colorado and northern New Mexico to petroleum fields in the Permian Basin of Texas and New Mexico, where it is used for EOR. The 10 largest coal-fired power plants in the Region produce about 127 million metric tons (140 million tons) of CO_2/yr. Other stationary sources include natural gas processing plants, refineries, ammonia/fertilizer plants, ethylene and ethanol plants, and cement plants.







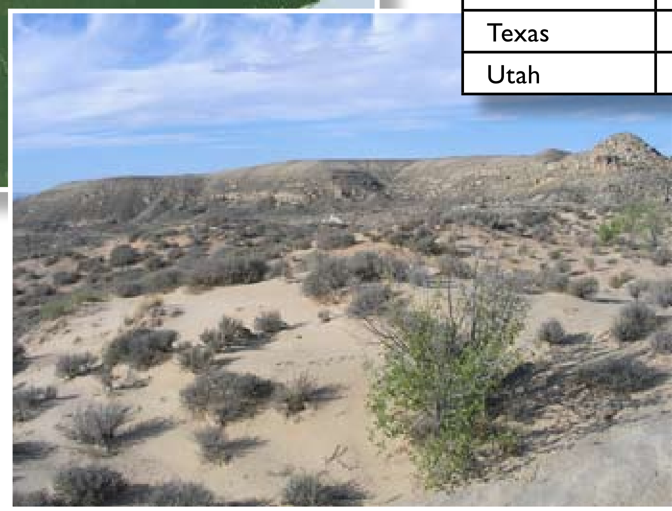
SWP Oil and Gas Reservoirs

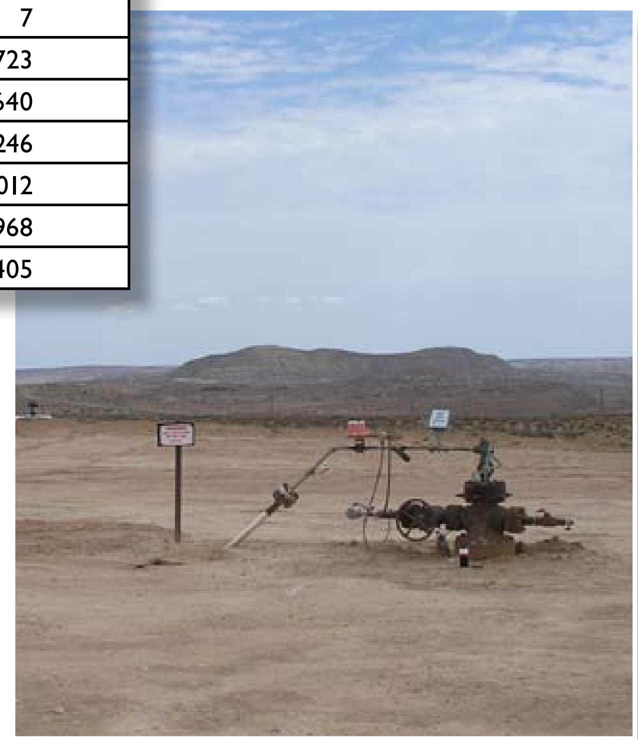
The Aneth oil field, discovered in 1956, is among the largest in the nation. The Aneth field is located in the Paradox Basin of southeastern Utah. Aneth is a stratigraphic trap with fractures and minor faults, and covers approximately 16,800 acres. The field has produced about 149 million barrels of an estimated 421 million barrels of original oil in place. The pilot test site is located within the Aneth mound complex, which formed on a weak structural nose. The present day maximum structural relief of 150 feet is largely the result of differential compaction. The primary CO_2 sequestration test target is the Pennsylvanian Desert Creek and overlying Ismay members of the Paradox formation, the primary producers in the Greater Aneth Field.

In Texas, the SACROC oil field produces from Pennsylvanian-age strata. SACROC lies along a trend of fields described as the Horseshoe Atoll Play. Target sequestration reservoirs in SACROC include the producing Pennsylvanian carbonates.

Oil and Gas Reservoir CO_2 Storage Resources by State (million metric tons)

State	CO_2 Storage Resource
Arizona	7
Colorado	1,723
Kansas	1,640
New Mexico	8,246
Oklahoma	10,012
Texas	41,968
Utah	1,405





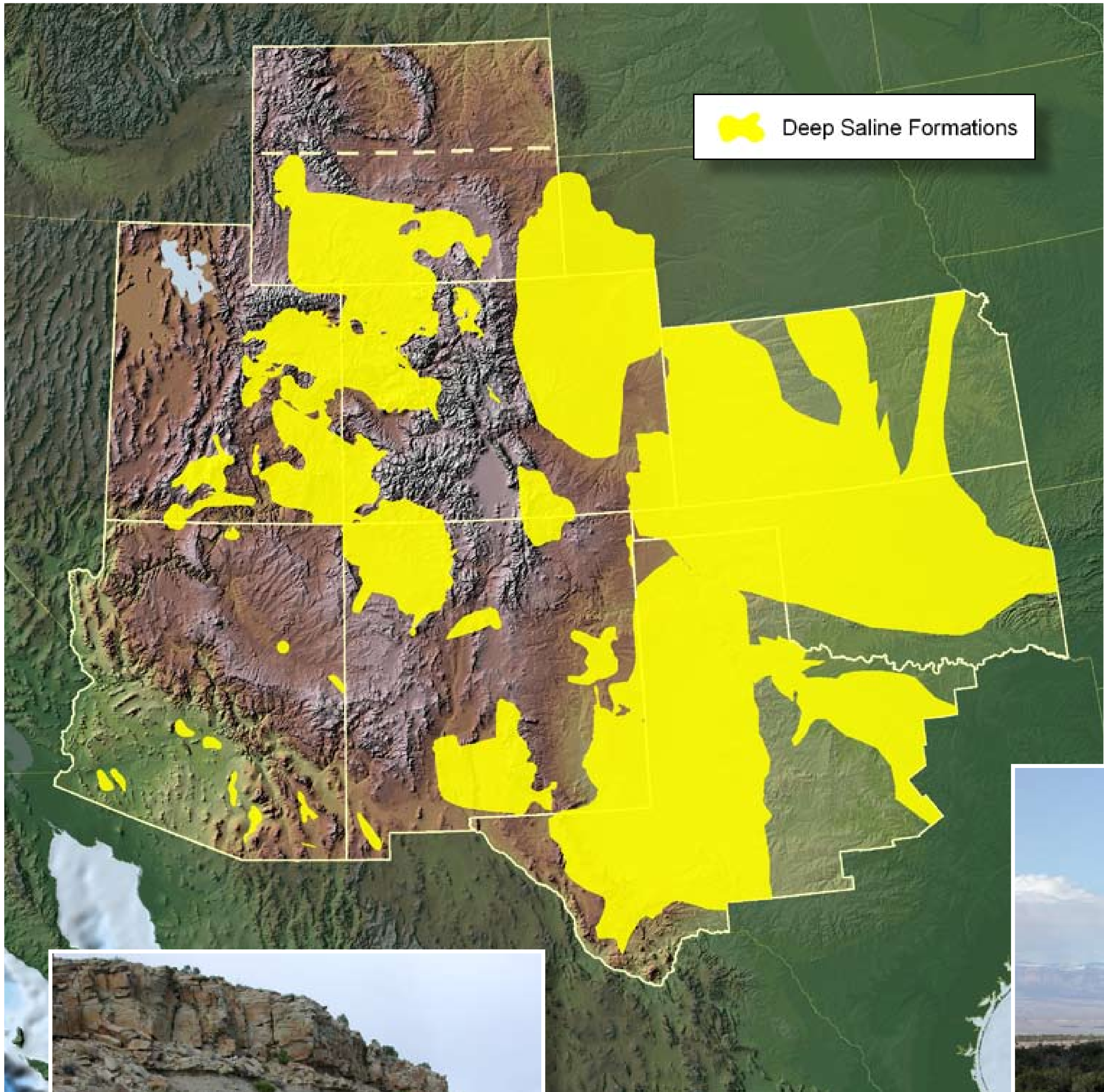
SWP Coal Seams

The San Juan Basin in New Mexico is one of the top ranked basins in the world for CO_2 coalbed sequestration due to (1) advantageous geology and high methane content; (2) abundant anthropogenic CO_2 from nearby power plants; (3) low capital and operating costs; (4) well developed natural gas and CO_2 pipeline systems; and (5) local companies with CBM and ECBM expertise. Because of its enormous coal storage resource, the San Juan Basin offers a tremendous sequestration opportunity with value-added natural gas production. An extensive CO_2 infrastructure is already in place, making the area ready for future operations.

The coals in the Basin fairway area are of exceptionally high permeability. Due to the tendency of coal to swell when in contact with CO_2, high initial coal permeability is required to maintain high CO_2 injection rates over time. Maintaining high injectivity is an important requirement for large-scale, low-cost CO_2 sequestration in coal.

Coal Seam CO_2 Storage Resources by State (million metric tons)

State	Low CO_2 Storage Resource	High CO_2 Storage Resource
Arizona	0.1	0.1
Colorado	489.3	857.3
Kansas	2.1	8.4
New Mexico	75.4	301.8
Oklahoma	1.8	7.4
Utah	30.5	122.1
Wyoming	194.3	777.2

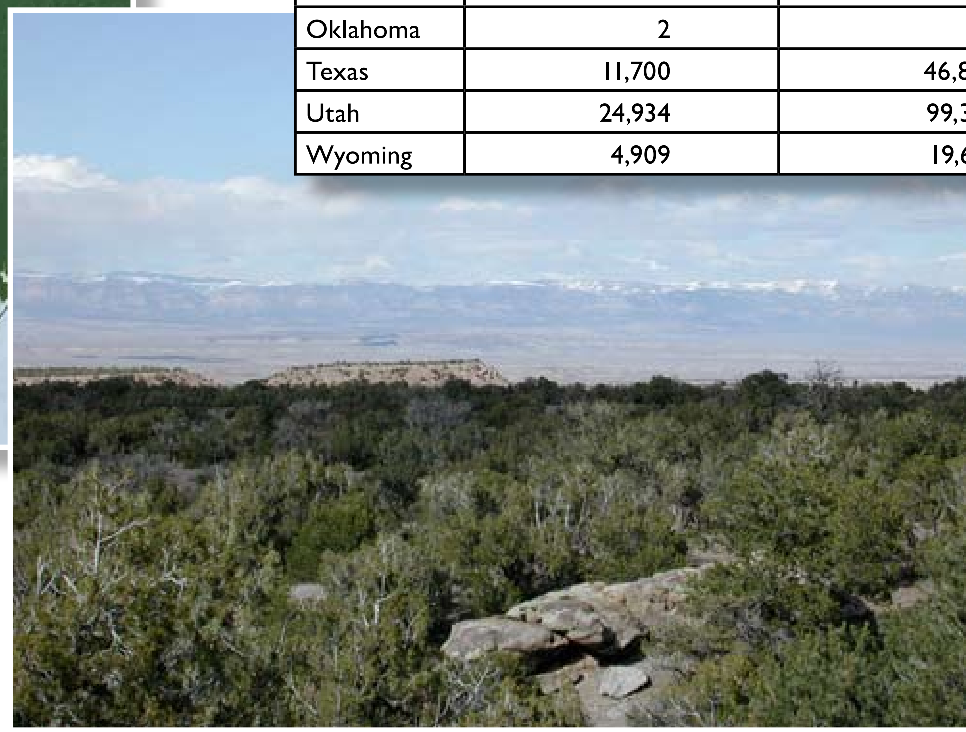


SWP Saline Formations

Farnham Dome, an elongated surface anticline located along the northern plunge of the San Rafael uplift and the southwestern edge of the Uinta Basin, contains numerous saline formations for large-scale CO_2 injection. Commercial-sequestration target formations for this site include many Jurassic and older formations. Specific targets for testing include the Permian White Rim sandstone and the Jurassic-Triassic Wingate sandstone. Saline formations make up a large portion of the United States CO_2 storage resource (estimated at 919 billion metric tons [1,013 billion tons]), with the added benefit of being in close proximity to CO_2 stationary sources.

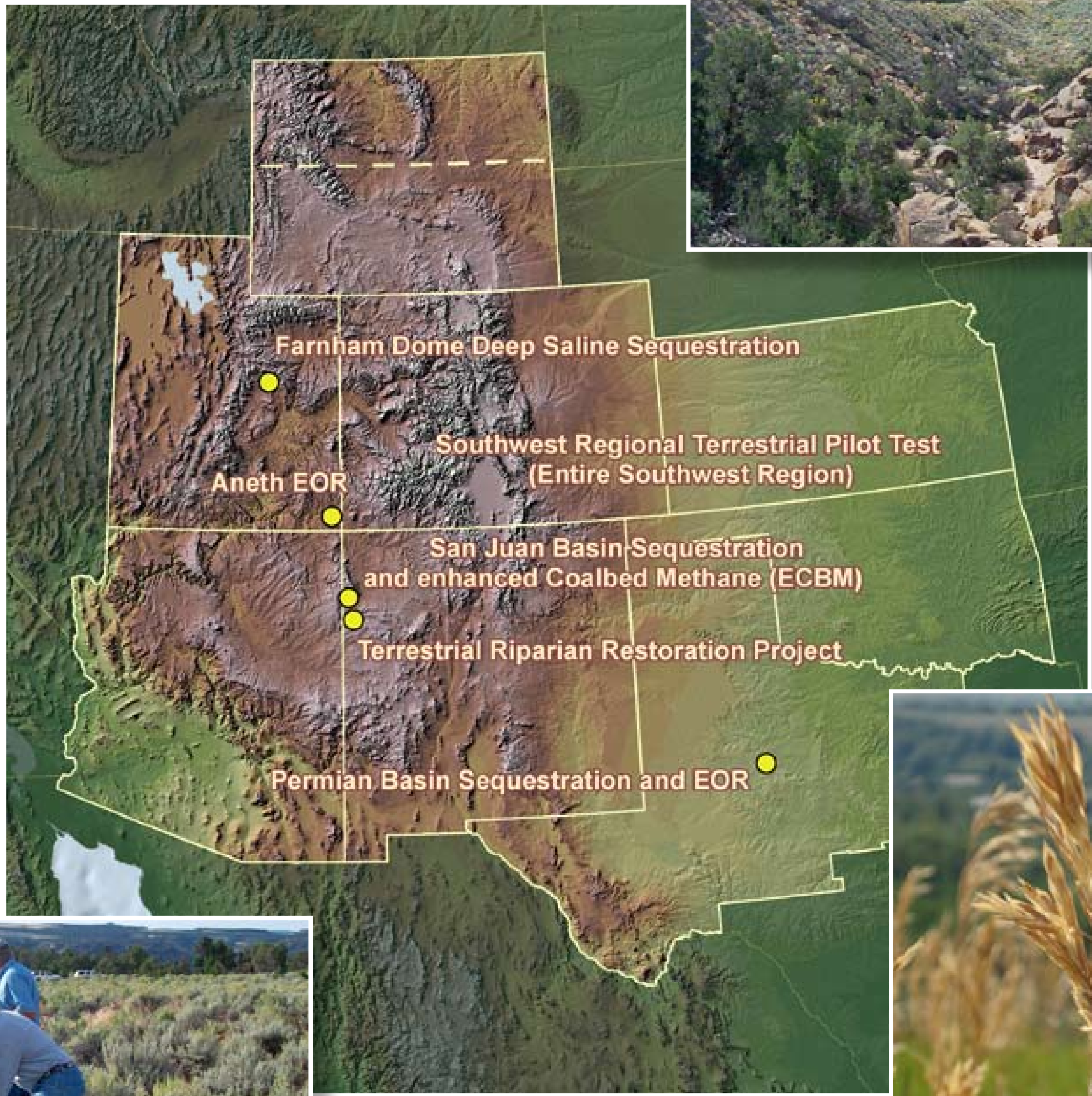
Saline Formation CO_2 Storage Resource by State (million metric tons)

State	Low CO_2 Storage Resource	High CO_2 Storage Resource
Arizona	199	752
Colorado	18,828	75,313
Kansas	8	9
Nebraska	87	348
New Mexico	33,054	132,215
Oklahoma	2	9
Texas	11,700	46,800
Utah	24,934	99,305
Wyoming	4,909	19,636



SWP Terrestrial Opportunities

In conjunction with the SWP's ECBM sequestration test, a terrestrial pilot test is being conducted in the San Juan Basin. ECBM operations are notorious for producing huge volumes of water. This water source could potentially be desalinated and used for irrigating a riparian restoration project, forming a combined ECBM – terrestrial sequestration project. Though the desalination process is an expensive one, the BLM and ConocoPhillips are both interested in making beneficial and environmentally-friendly use of the produced water. Rangelands in the San Juan Basin of New Mexico are a plausibly large reservoir for carbon, in addition to their value as recreational lands. The challenges to achieving the rangelands' potential lie primarily in the limited growing conditions and reduced capacity for recovery. Optimizing carbon storage in soils and vegetation while increasing the value of other ecosystem services requires a two-pronged strategy: enhancing existing and reintroducing woody plant species along riparian areas, and reestablishing native grasses and shrubs in upland areas. The limiting factor in both cases is water. A reliable source of water for agricultural irrigation, such as the water produced during ECBM production, could provide the necessary base for the reestablishment of native vegetation with a host of environmental benefits, as well as carbon sequestration. In addition to the terrestrial pilot test, the SWP is also conducting an extensive terrestrial analysis of the Region.



San Juan Basin, New Mexico—ECBM

San Juan Basin, New Mexico—Terrestrial

Paradox Basin, Utah—EOR

Permian Basin, Texas—EOR

SWP: Validation Phase Field Tests

San Juan Basin, New Mexico—Enhanced Coalbed Methane: The SWP is conducting the San Juan Basin ECBM field validation test in cooperation with ConocoPhillips. This test, begun in July 2008, will inject up to 35,000 tons of CO_2, to evaluate concomitant coalbed methane production and CO_2 storage optimization.

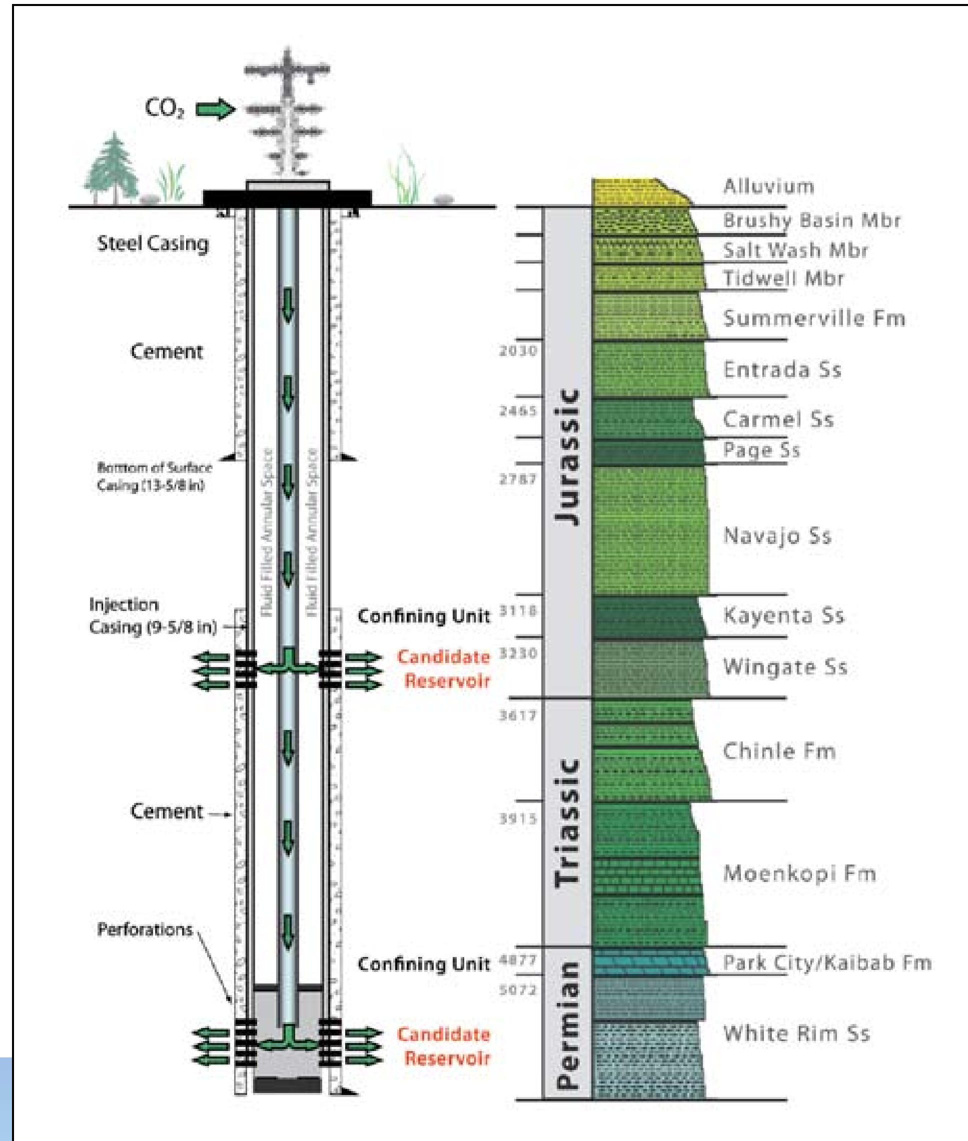
San Juan Basin ECBM Terrestrial Sequestration Pilot: The San Juan Basin ECBM project is also the location of one of the terrestrial sequestration pilot tests. Produced water from the ECBM project and other wells will be desalinated and applied to a drought-stressed riparian area—the interface between land and a flowing surface water body—where carbon storage will be monitored and evaluated.

Paradox Basin, Utah—Enhanced Oil Recovery: At the Aneth oil field near Bluff, Utah, the SWP is conducting a CO_2 EOR storage test on an active CO_2 EOR site managed by Resolute Natural Resources Company and the Navajo Nation Oil and Gas Company. From August 2007 until September 2009, up to 136,000 metric tons (150,000 tons) of CO_2 will be injected per year over the 2-year period. Based on extensive geologic characterization and detailed reservoir models, SWP will design MVA protocols and conduct field studies.

Permian Basin, Texas—Enhanced Oil Recovery and Sequestration: The SWP is evaluating CO_2 EOR efficiency and CO_2 storage optimization at the SACROC field validation test site—a combined EOR/CO_2 storage operation—in cooperation with Kinder Morgan CO_2 Company, L.P. In late 2008, approximately 318,000 metric tons (350,000 tons) of CO_2 per year for 1 1/2 years will be injected. The geologies of Aneth and SACROC, both carbonate reservoirs, are similar, but their depth ranges vary, offering an opportunity to examine different hydrodynamic settings, which impact the flow and fate of CO_2 in the reservoir.

SWP: Development Phase Field Tests

Farnham Dome, Utah – Deep Saline Formation: In addition to the San Juan Basin, Paradox Basin, and Permian Basin projects, SWP has added a fourth test site for the Development Phase—Farnham Dome, located along the southwestern edge of the Uinta Basin in Central Utah. The SWP and its industrial partners, including Savoy Energy LLC, Rocky Mountain Power, Questar Gas, Southern California Edison, Pacificorp and others will test the effectiveness of deep saline formations for carbon sequestration capabilities. Mitigation planning and a rigorous risk assessment for the area are also important goals for the Farnham Dome site. Drilling of injection wells and monitoring wells will begin in mid-2009. Injection of CO_2 will continue into 2012 and will include injection of up to 1 million tons of CO_2 per year. Monitoring of the injection site will continue until at least 2017. The SWP is targeting saline formations, including deep Jurassic and older geologic strata. The SWP will test dual- injection intervals at the site, also called “stacked storage,” to maximize capacity evaluation and optimize monitoring efficacy. Carbon dioxide from the Farnham Dome site will be transported to the Uinta Basin EOR market by pipeline. Potential future commercial opportunities associated with Farnham Dome CO_2 include enhanced oil recovery applications in the broader Uinta Basin.



SWP Opportunities for Commercialization

U.S. Energy and Economic Security

Fossil fuels are projected to remain a bastion of U.S. energy production for the rest of the 21st century. As the U.S. supply of oil decreases over time, the Nation will turn to other abundant domestic resources, such as coal and renewables, to minimize dependency on foreign oil and to ensure a reliable energy supply. Consistent, affordable energy supplies are linked to economic growth and prosperity. Energy is not a negotiable commodity—it is needed to run businesses, to power homes, and to transport goods. As new and enhanced domestic fossil fuel resources are developed, industry is challenged to mitigate on-site carbon emissions. CO_2, a by-product of fossil fuel combustion, is thought to contribute to global warming. As the threat of climate change becomes more apparent, the research community and governments are seeking ways to regulate CO_2 emissions at the source. The energy sector is a major contributor of greenhouse gases. In the Southwestern U.S., 95 percent of CO_2 emissions result from fossil fuel combustion and approximately one-half of those emissions are from power plants. Indeed, inexpensive and effective means to reduce CO_2 are necessary to ensure continued growth and development of new and enhanced fossil fuel-derived energy resources.

Market-based Opportunities

SWP is currently testing geologic and terrestrial CO_2 sequestration in the San Juan, Permian, and Paradox Basins as well as Farnham Dome, which reside in a major energy-producing region of the United States that includes abundant preexisting infrastructure suitable for sequestration activities. If the technology proves safe, reliable, and cost-effective, it will not only reduce the cost of regulatory-based CO_2 mitigation options, but substantial market penetration is anticipated within the next decade. This new technology offers the ability to develop an industry based on clean-burning oil, gas, and coal. With increasing support from industry and environmental constituents, CO_2 sequestration is now a catalyst for new, innovative ideas and investment capital. Funded in part by industry, state and federal governments, the advancement of this technology is expected to grow rapidly and eventually penetrate public and private energy sectors. Making way for new environmentally-friendly fuel resources, CO_2 sequestration technologies may provide a reliable, low-cost flow of energy for decades to come.

SWP Opportunities for Commercialization

Added Benefits to Industry

- Geologic carbon sequestration uses the same technologies that have been developed by the oil and gas industries. These technologies now provide an opportunity to offset carbon emissions through sequestration, allowing industry to prepare for or get ahead of anticipated state and federal regulations.
- Enhanced Oil and Gas Recovery: The injection of CO_2 into a geologic formation can enhance the recovery of hydrocarbons, providing value-added byproducts that can offset the cost of CO_2 capture and sequestration such as the recovery of oil or gas from a site that was not previously producing.
- Carbon sequestration in unmineable coal seams can enhance the recovery of methane gas because CO_2 promotes desorption which is needed for methane to separate from coal.
- Industry can accumulate carbon credits that can be traded on the global market.
- Close proximity to geologic repositories reduces transportation of CO_2 costs significantly.
- A market for sequestration is anticipated to develop when industries are mandated to offset their carbon emissions.
- Voluntary reduction of emissions and development of a market for sequestration provides industry in the Southwest an economically viable alternative to carbon emission mitigation as opposed to other propositions requiring extensive facility retrofit. Support of carbon sequestration technology also provides an alternative to policy makers who, in response to a growing demand for regulation, might support more stringent measures.

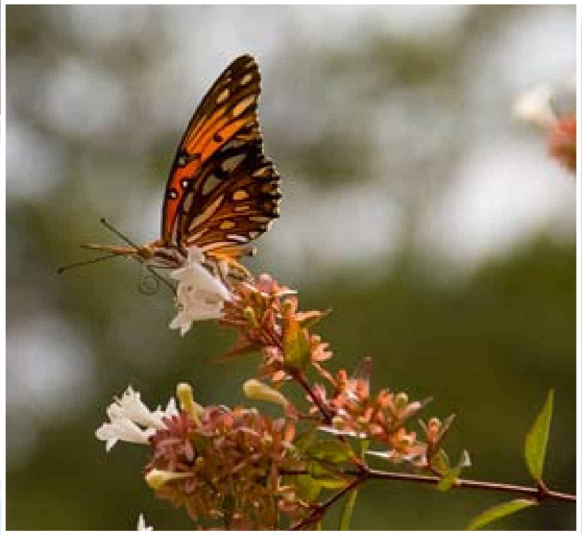


Photo Credits—Picture contributors for the SWP section of the 2008 Carbon Sequestration Atlas of the United States and Canada include the following: Andrea Feldpausch, Craig Morgan, Damon Hall, Israel Parker, Jason Heath, Mark Holtz, and Shawn Salley.

West Coast Regional Carbon Sequestration Partnership

The West Coast Region, consisting of the states of Alaska, Arizona, California, Hawaii, Nevada, Oregon, Washington, and the Canadian province of British Columbia, is characterized by a wealth of natural resources, varied ecosystems, and a large and growing population imbued with an entrepreneurial spirit. In addition to cultural, economic, and geographic diversity, the Region has one of North America's broadest mixes of CO_2 sources and an equally broad array of opportunities to curb atmospheric CO_2 buildup through carbon sequestration.

The West Coast Regional Carbon Sequestration Partnership (WESTCARB), led by the California Energy Commission, comprises researchers from more than 80 public agencies, private companies, and nonprofits. WESTCARB's goal is to identify and map the regional opportunities for geologic and terrestrial carbon sequestration and to validate the feasibility, safety, and efficacy of some of the best regional opportunities through field tests.

Results of WESTCARB characterization studies to date show excellent carbon sequestration potential throughout the Region. Numerous EOR and enhanced gas recovery (EGR) opportunities, as well as ECBM, offer the potential for geologic sequestration to be coupled with economic incentives. In addition, broadly distributed sedimentary basins believed to contain saline formations have the potential to store hundreds of years' worth of the Region's CO_2 stationary source emissions. Terrestrial sequestration opportunities are among the best in North America and provide a viable approach to offsetting some of the Region's relatively large transportation-related CO_2 emissions.

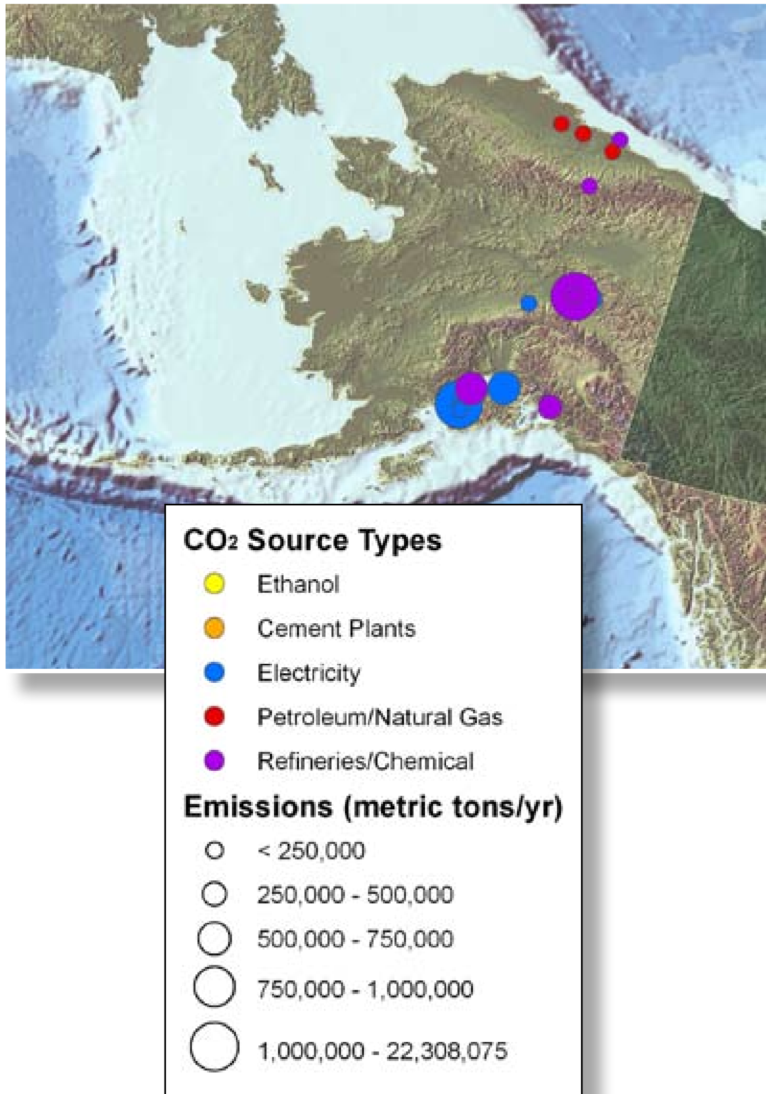
WESTCARB researchers believe that carbon sequestration can play an important role in state and provincial efforts to address climate change as policymakers and the public seek ways to protect the environment and ensure healthy economies.

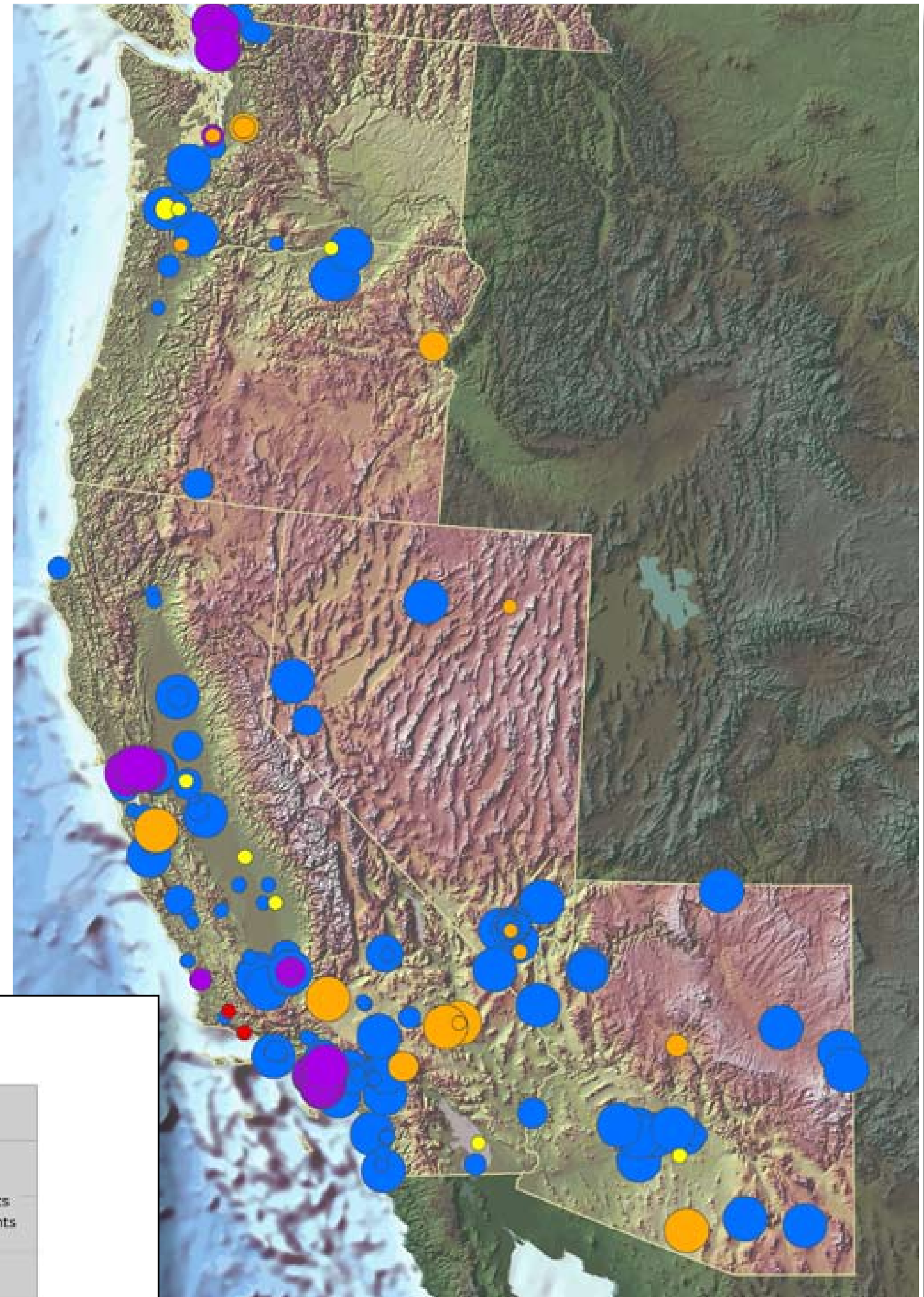
WESTCARB CO_2 Emission Sources

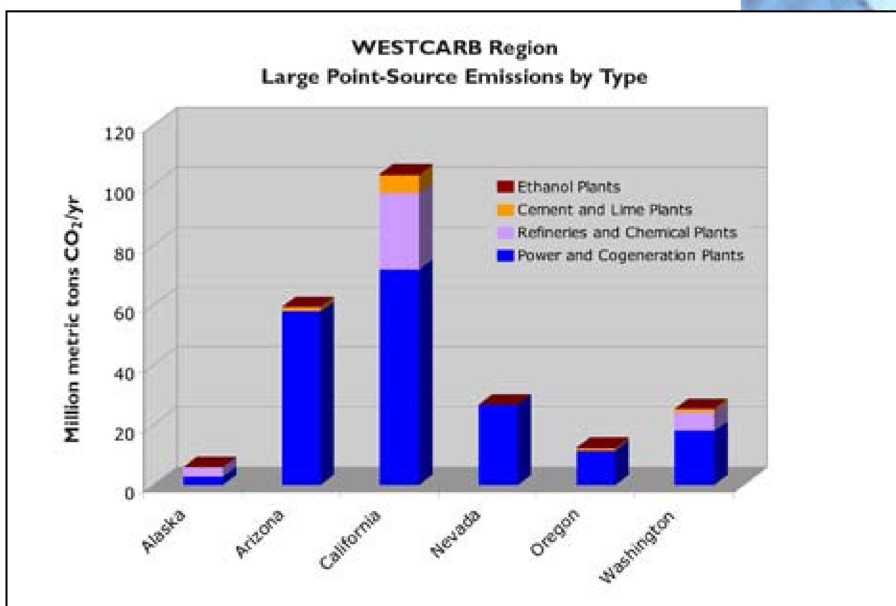
The WESTCARB states account for approximately 11 percent of U.S. CO_2 emissions. About half of the Region's emissions come from the transportation sector, while more than a third come from industrial and electric power sectors. California ranks second among all states in CO_2 emissions, with the transportation sector accounting for the majority of the state's total. The large percentage of emissions from mobile sources underscores the importance of developing terrestrial sequestration options (as well as biofuels plants with geologic sequestration) to provide a mechanism for offsetting these hard-to-capture emissions.

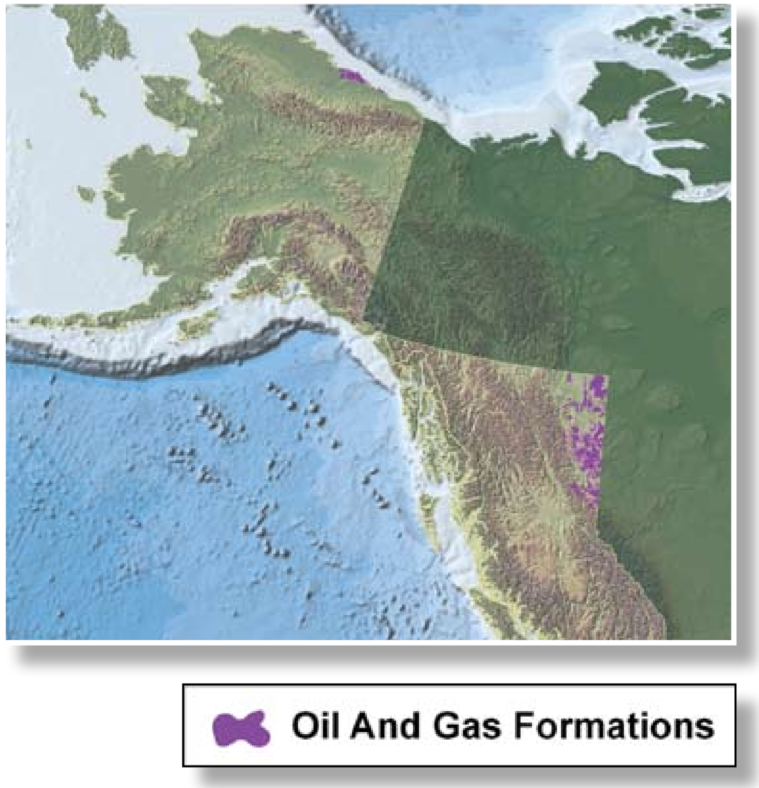
The largest stationary sources in the Region are electric power and co-generation plants, oil refineries, and cement and lime plants. Electric power plants are the single largest CO_2 stationary source type, with California and Arizona electric power/co-generation plant CO_2 emissions considerably higher than other states in the Region. Arizona's power plants are mostly coal-fired, whereas California's are predominantly natural-gas-fired, which makes the cost of CO_2 capture generally higher in California. Additionally, without adoption of carbon sequestration measures, CO_2 emissions from ethanol and other biofuel plants (currently small) have the potential to grow rapidly as the alternative fuel industry expands.

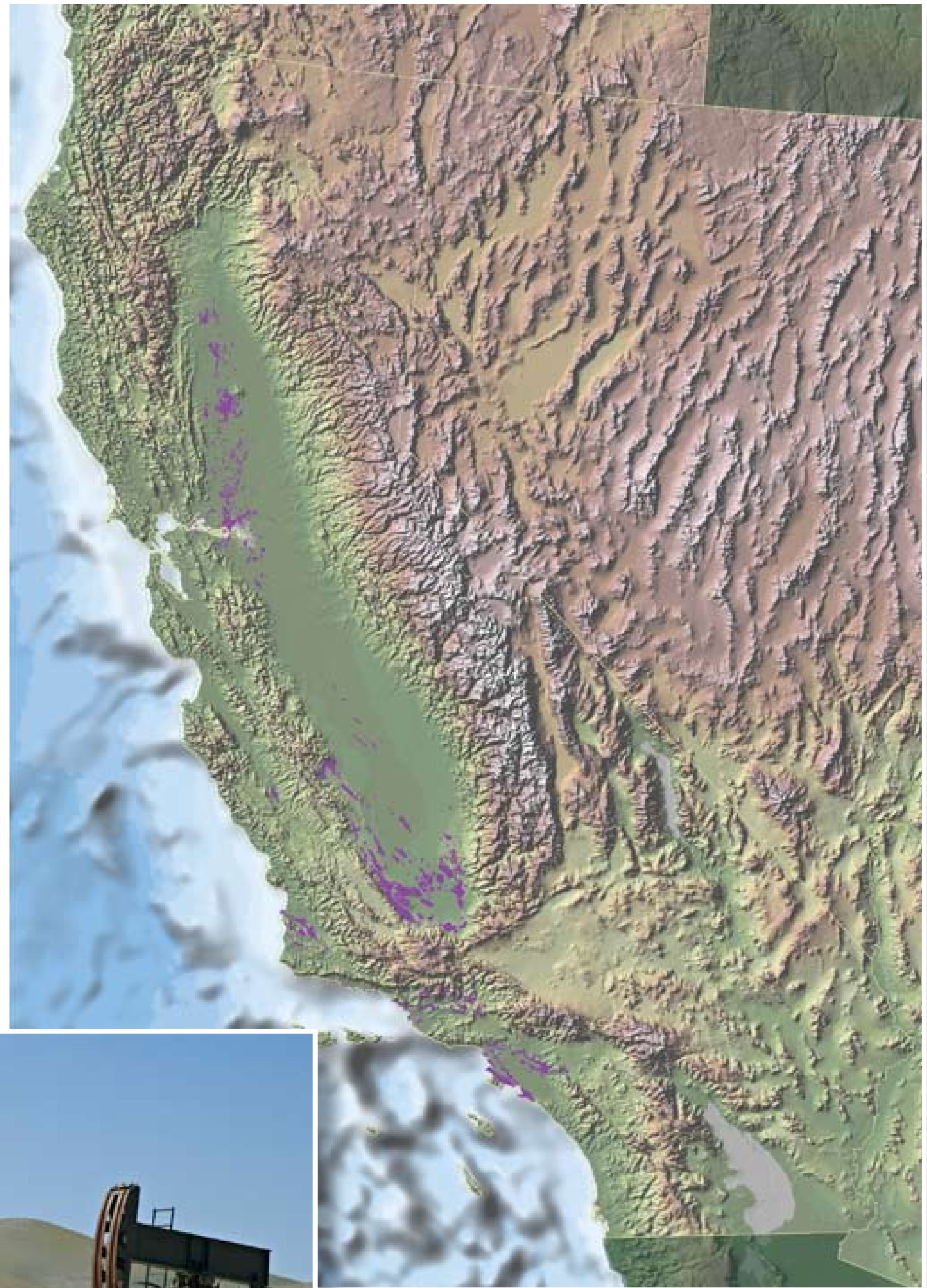
The WESTCARB CO_2 sources database (which is also served to NATCARB) includes information for more than 250 of the largest emitting power and industrial facilities in the WESTCARB Region.











In conjunction with geologic sequestration, additional production may be achieved in some oil fields through CO_2 EOR, even when secondary recovery methods have already been applied.

WESTCARB Region Oil and Gas Fields

In the WESTCARB Region, major oil and gas fields represent both sequestration targets and EOR/EGR opportunities—especially in California and Alaska.

In California, most oil reservoirs are found in the southern San Joaquin Basin, Los Angeles Basin, and southern coastal basins. Estimates made by WESTCARB investigators suggest a potential CO_2 EOR storage resource of 3.7 billion metric tons (4.1 billion tons), based on a screening of reservoirs using depth, crude oil gravity, and cumulative oil produced. A DOE study of CO_2 EOR potential in California suggests that technically recoverable reserves exceed 0.3 million m^3 (5.6 billion barrels).

Researchers also estimated an additional 2.5 billion metric tons (2.7 billion tons) of potential CO_2 storage in California non-EOR (i.e., depleted reservoir) storage applications.

The Sacramento River Delta is home to some of California's largest natural gas fields, which have been major producers since the 1930s. WESTCARB estimates the CO_2 sequestration potential in California natural gas reservoirs at 1.8 billion metric tons (1.9 billion tons).

In Alaska, the oil and gas fields on the North Slope are of prime interest because of the large potential for CO_2 EOR. The hydrocarbon reservoirs of the Cook Inlet offer potential for CO_2 enhanced recovery given their proximity to industrial CO_2 sources.

WESTCARB Coal Basins

Opportunities for geologic CO_2 storage in unmineable coal basins within the WESTCARB Region are found predominantly in the Pacific Northwest and Alaska. In the Pacific Northwest, three deep coal bed deposits offer promise: the Bellingham Basin in northwestern Washington; the coals of the upper Puget Sound Region, south and east of the Seattle-Tacoma metropolitan area; and small, deep coal deposits in southwestern Oregon.

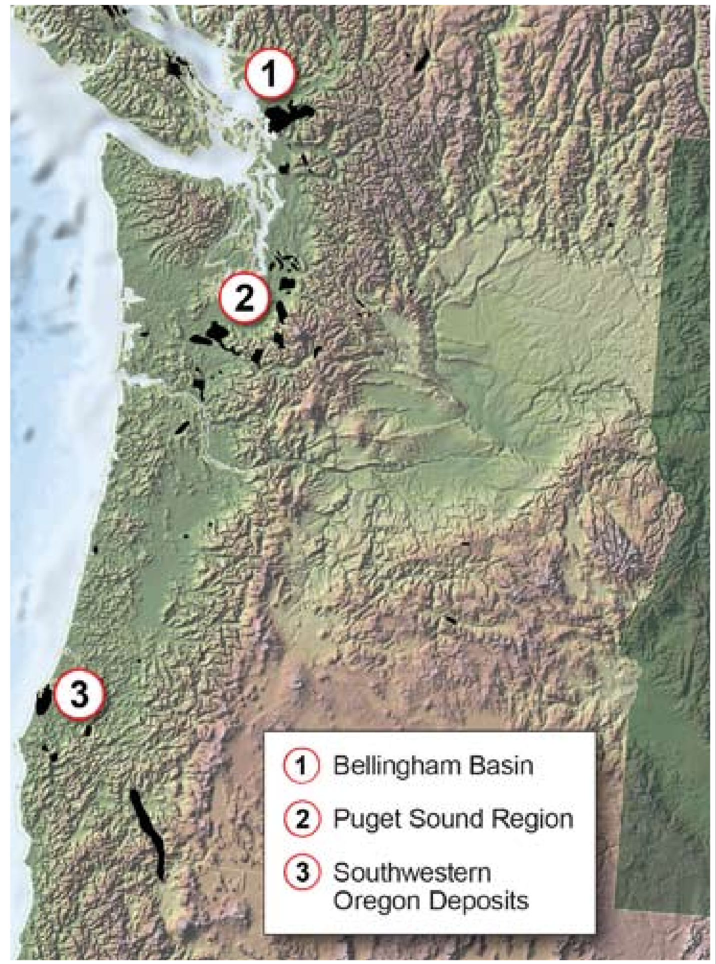
Puget Sound seams have been tested by several coal bed methane exploration companies, and WESTCARB investigators are characterizing their CO_2 sequestration potential. Preliminary results show that the subsurface extent of the coal basins represents an area greater than 2,500 km^2 (950 mi^2). Initial analysis indicates prospective coal seam reservoir properties of 30 m (100 ft) coal thickness, a CO_2 sorption capacity of 20–24 m^3 (700–850 ft^3) CO_2 per ton of coal, and a permeability of approximately 5 millidarcies. The estimated CO_2 storage potential in this area is 2.8 billion metric tons (3.1 billion tons), and the estimated recoverable CBM is 57–570 billion m^3 (2–20 trillion ft^3).

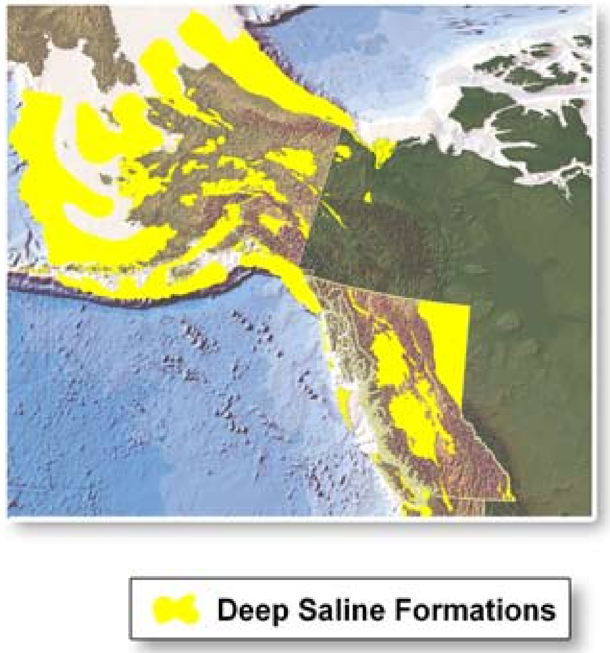
Although coal mining in Alaska has been very limited, the state contains major coal deposits that range from shallow to over 2,000 m (6,500 ft) deep. Essentially all of the CO_2 storage potential in unmineable coal beds lies in the North Slope and Cook Inlet regions, which have coals of suitable thickness, depth, and permeability.

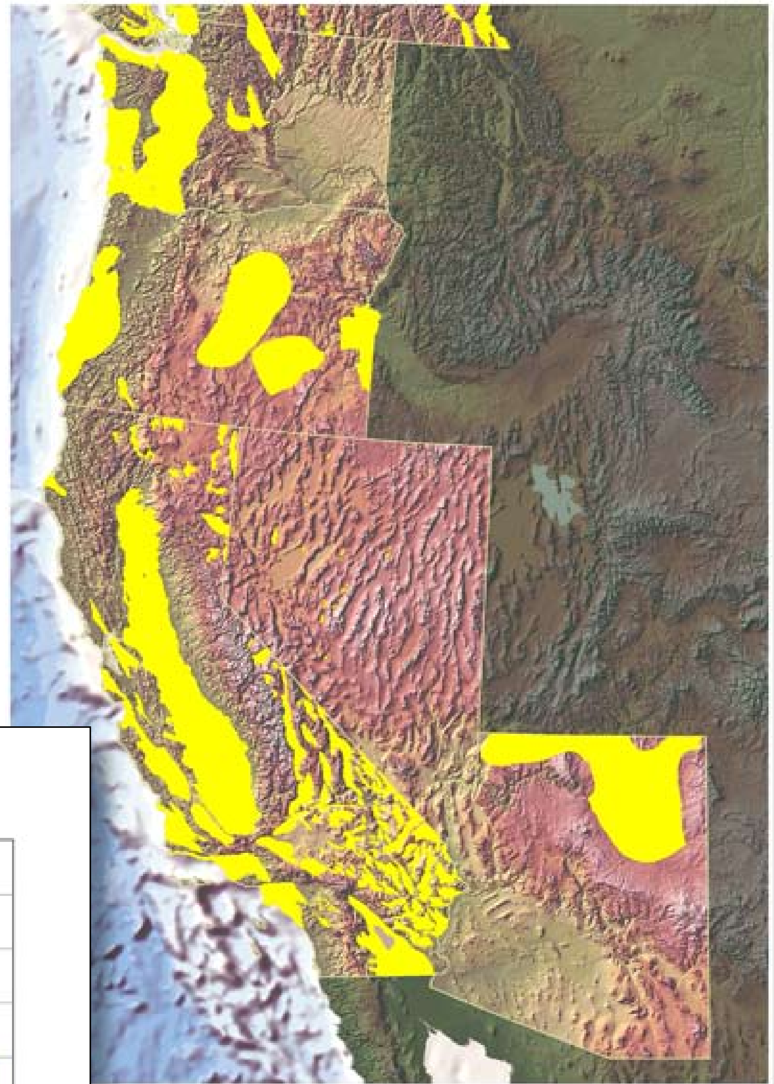
Preliminary estimates of geologic CO_2 storage resource in Alaska suggest that about 80 billion metric tons (90 billion tons) could be stored in deep coal seams. It is likely, however, that only a portion this total would be considered favorable for CO_2 sequestration, due to permeability, seam geometry, surface access, faulting, and other site-specific (but currently unknown) conditions. WESTCARB is continuing its analysis and expects to refine initial estimates as studies progress. Alaska's coal bed methane resources are estimated to be approximately 22 trillion m^3 (780 trillion ft^3), which is comparable to the CBM resources in all of the lower 48 states.

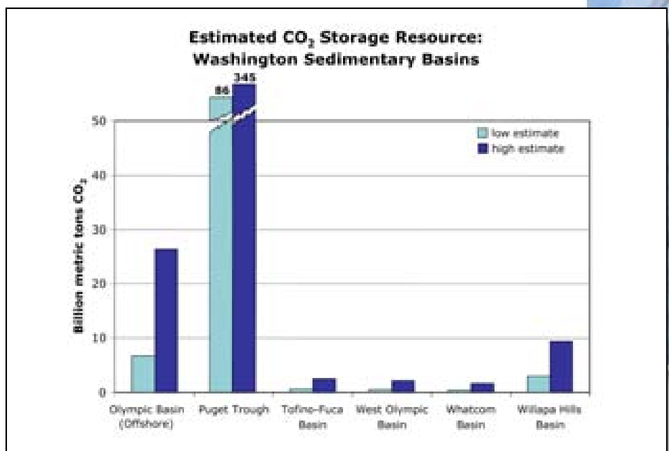
Map Credit: Flores, R., Stricker, G., and Kinney, S., "Alaska Coal Geology, Resources, and Coalbed Methane Potential." U.S. Geological Survey, DDS 77, 2004.

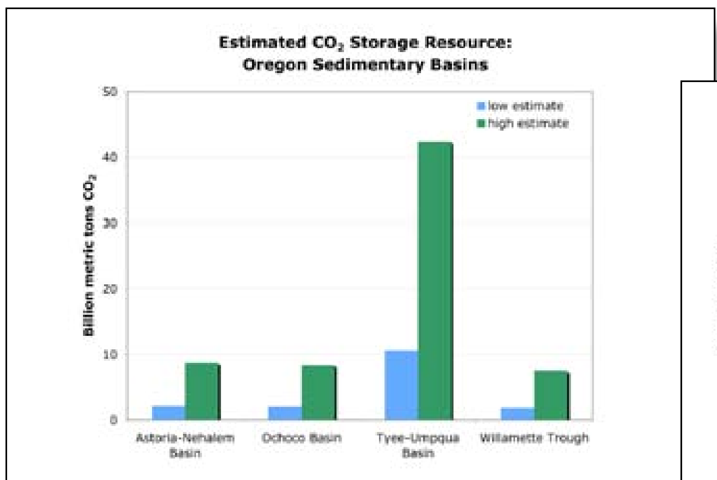
TransAlta's 1400 MW coal-fired power plant in Centralia, Washington.

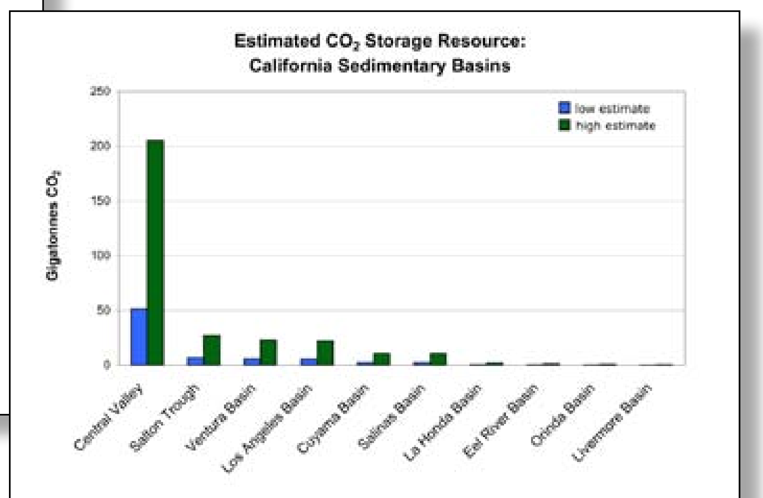












WESTCARB Saline Formations

Deep sedimentary basins are broadly distributed throughout the WESTCARB Region. Most are believed to be saline formations, and research is ongoing to bolster confidence in their salinity and to estimate their potential to store large volumes of the Region's industrially produced CO_2.

In California, for example, WESTCARB researchers consider Cenozoic marine sedimentary basins as offering the best potential for geologic sequestration. These basins exhibit a wide areal distribution, thick sedimentary sections containing multiple widespread saline-saturated sandstones, and thick and laterally persistent shale seals. Petrophysical data from past oil and gas development in many basins support researchers' assessments. In terms of potential CO_2 storage resource, WESTCARB ranks the San Joaquin, Sacramento, Ventura, Los Angeles, and Eel River basins as the most promising. Researchers estimate the aggregate CO_2 storage resource of the 10 largest basins at approximately 80–300 billion metric tons (90–330 billion tons) CO_2.

In Oregon and Washington, 10 western coastal basins offer potential sequestration opportunities. These basins contain sandstone and shale sequences up to 9,000 m (30,000 feet) thick. The largest in terms of potential CO_2 storage resource is Washington's Puget Trough. The total CO_2 storage resource for the 10 sedimentary basins is approximately 120–450 billion metric tons (130–500 billion tons).

Areas of potential for CO_2 sequestration in Nevada are Granite Springs Valley in Pershing County, Antelope and Reese River Valleys in Lander County, and Ione Valley in Nye County. Each appears sufficiently large areally and is filled with sediments and volcanic rocks. Site characterization studies will be needed to determine if CO_2 storage capacity exists beneath these valleys.

In Arizona, the sediments underlying the Colorado Plateau in Arizona, including the Naco and Martin formations, represent sequestration opportunities and are in the vicinity of several large coal-fired power plants. Both the potential storage targets and seals are laterally extensive and up to hundreds of feet thick.

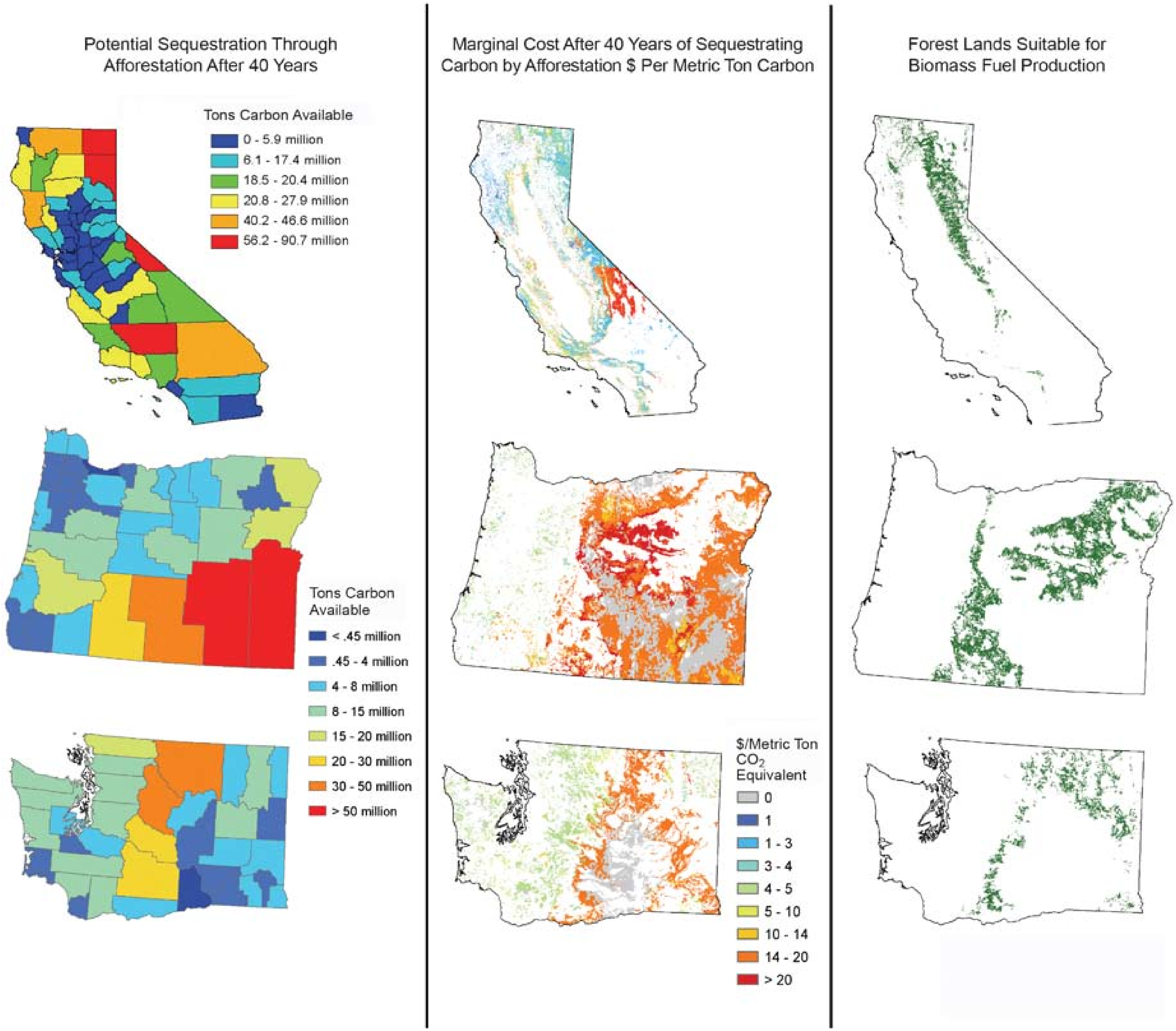
In Alaska, the potential CO_2 storage resource may be massive, but researchers are focusing on the Cook Inlet Basin because of its proximity to industrial CO_2 sources.

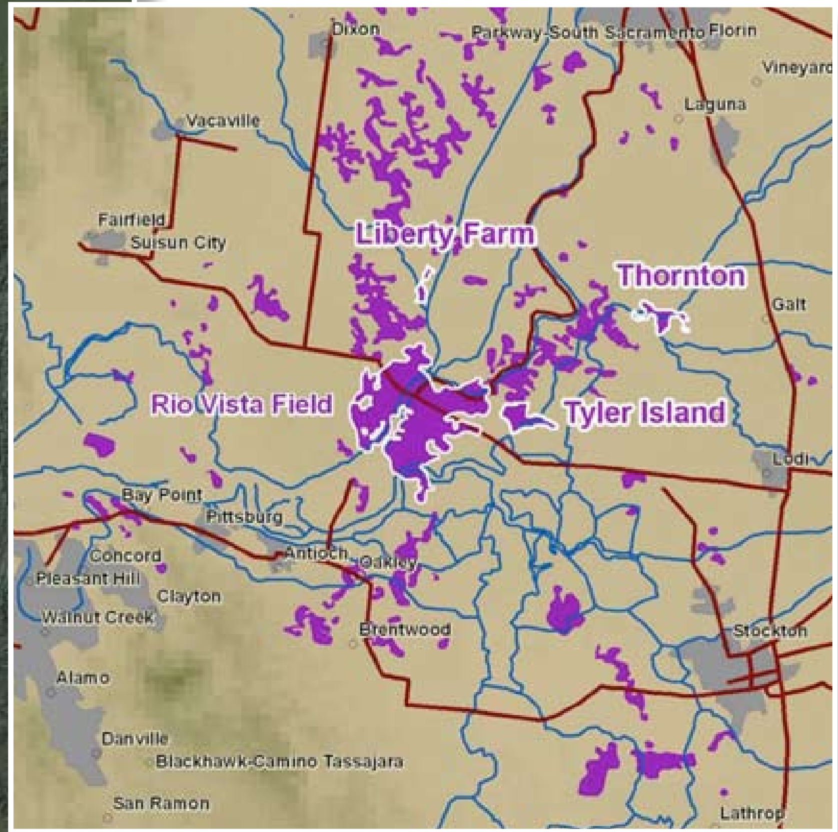
WESTCARB Terrestrial Carbon Sequestration Opportunities

Major terrestrial sequestration opportunities in the WESTCARB Region include afforestation of rangelands and agricultural lands, changes in forest management to increase carbon stocks, improved management of forest fuels to reduce emissions from wildfires, and (where practical) the use of these fuels in biomass energy facilities.

WESTCARB researchers evaluated afforestation of rangelands for California, Oregon, and Washington over 20-, 40-, and 80-year time periods. On a dollar per ton of CO_2-equivalent basis, costs are lowest for the longer timespans because the planted trees have more time in their prime growing years, and the initial costs of land preparation and planting are amortized over a larger quantity of sequestered carbon. Successful project development entails analysis of forest suitability of candidate lands; a thorough understanding of total costs, including opportunity, conversion, maintenance, measurement, and monitoring costs; gauging the potential variability in sapling survival and tree growth rates; and the aggregate area and geographic distribution of potentially afforested lands. Afforestation of Oregon and Washington lands currently in hay and wheat production was also evaluated.

Forest management options examined by WESTCARB include widening riparian buffer zones, lengthening harvest rotations in commercial forests, and (for California only) variable retention techniques in commercial forestry operations. Also analyzed was the feasibility of removing fuels from wildfire-prone forests for transport to biomass energy plants. This assessment took into account the suitability of lands for fuel reduction, treatable area, and biomass yield under typical treatment programs.





Major Sacramento Delta natural gas fields (in purple) in the vicinity of the proposed California CO_2 storage pilot attest to extensive potential storage capacity and commercialization opportunities.

Assessment of coal seams in Washington state.

Ash pond near Cholla Power Plant in Arizona, site of the Arizona Utilities CO_2 Storage Pilot.

WESTCARB Geologic Field Tests

WESTCARB is conducting three pilot-scale geologic CO_2 injection tests and two site characterization pilots.

The Arizona Utilities CO_2 Storage Pilot will test the storage capability of a saline formation in the northeast portion of the state, part of the extensive Colorado Plateau. The area's naturally occurring CO_2 accumulations attest to the feasibility of safe, long-term geologic storage. The potential CO_2 storage resource within the Colorado Plateau is estimated to be large because of the thickness—more than 100 m (330 ft)—of deep-lying, porous saline formations and the presence of good seals. Available data suggest that suitable storage sites may be found beneath or near Arizona's coal-fired power plants. The Arizona pilot will help define the feasibility of using these sites for future commercial CO_2 storage projects.

A geologic CO_2 storage pilot in a saline formation is planned for the Sacramento River Delta in central California. Decades of experience with natural gas production and storage have provided excellent knowledge of local geology, and evidence suggests that the area's sandstone formations can safely store CO_2 for extremely long periods.

CO_2 injection into depleting gas reservoirs could potentially enhance gas recovery, after which the injected CO_2 could remain stored.

WESTCARB's site characterization pilots are evaluating (1) the CO_2 injectivity and storage potential of deep Puget Sound (Washington state) coal seams and other geologic formations near TransAlta's Centralia coal-fired power plant, and (2) the potential for CO_2 storage in the saline formations and depleting oilfields in the southern San Joaquin Valley of California. The latter pilot is providing important initial data and modeling for WESTCARB's Development Phase large-volume CO_2 storage test at Clean Energy Systems' Kimberlina facility in Kern County.

WESTCARB Terrestrial Field Validation Tests

WESTCARB's terrestrial carbon sequestration field tests are under way in Shasta County, California, and Lake County, Oregon.

In Shasta County, afforestation activities entail restoring native conifer and oak species to rangelands and fire-damaged forest lands on about a dozen plots ranging from 10 to 100 acres each.

In Lake County, researchers are studying the feasibility of establishing plantations of fast-growing trees, such as hybrid poplars, on suitable agricultural or grazing land, which could be harvested on short rotations to fuel biomass power plants.

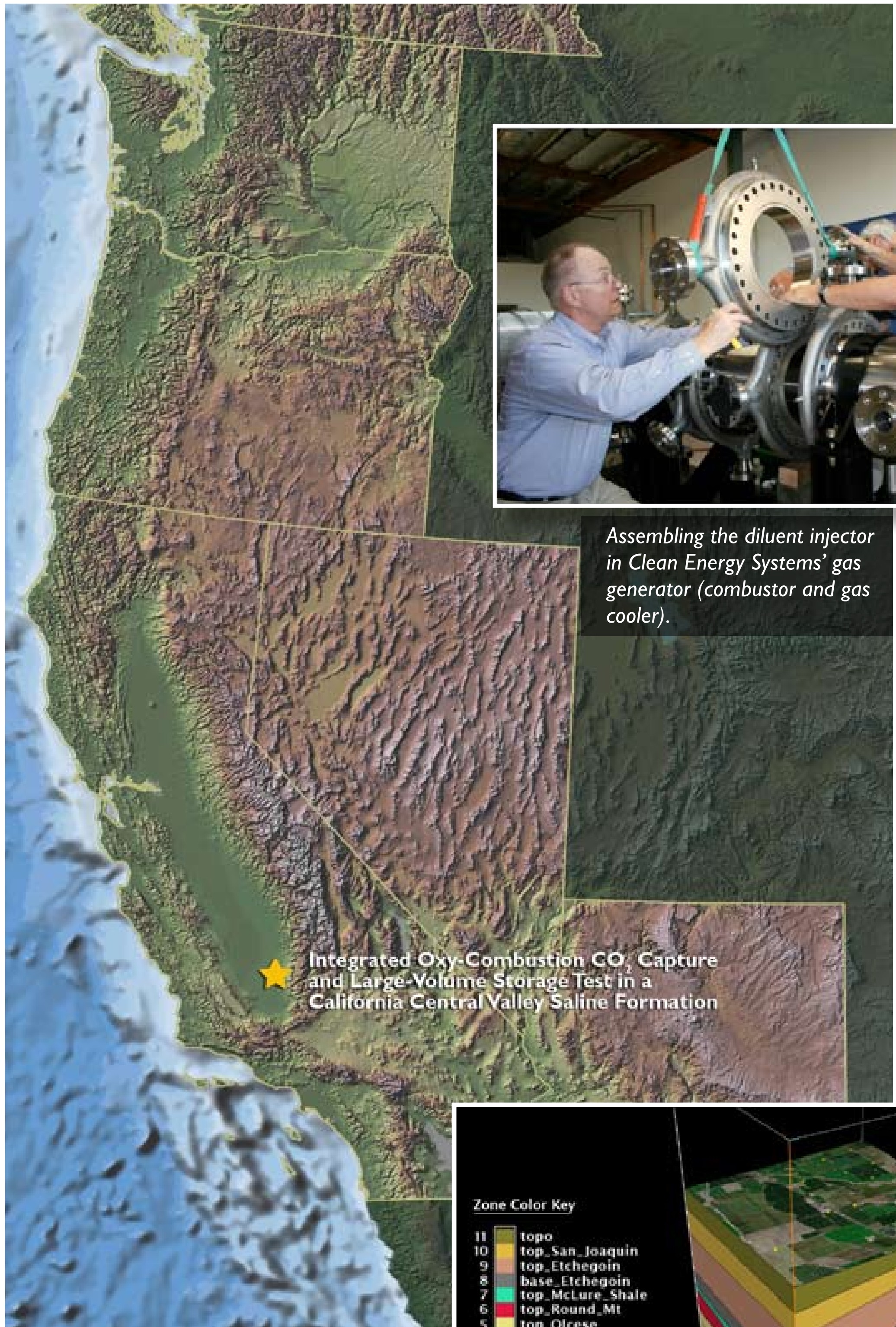
Both the California and Oregon pilots also involve research into carbon sequestration coupled with fire risk management through forest fuel reduction. Fire-prone forests are being treated to restore forest health by removing understory trees, brush, and other fuels that could contribute to catastrophic wildfires and the associated large GHG emissions. Where feasible, the removed fuel in Shasta County is being transported to a local biomass power plant to generate electricity, which can offset power demand that may otherwise be met by fossil fuel combustion.

The Shasta County pilot also features a conservation-based forest management project where a conservation group and timber company are working together to restore and maintain high-quality forest habitats and test the practicality and effectiveness of forest carbon accounting protocols.

Measuring and monitoring activities are an important component of all WESTCARB terrestrial sequestration field tests. Overall objectives are to quantify the CO_2 emission reductions/sequestration attributable to each activity; gather information on costs and benefits to landowners; design measurement, monitoring, and verification methods; evaluate the practicality of existing reporting protocols to quantify verifiable reductions; and explore questions of market validation for terrestrial sequestration activities.

Measuring and monitoring activities establish carbon baselines and quantify carbon stored through terrestrial sequestration projects.

Replanting after a fire can re-establish a forest (left side of fence) and prevent colonization by invasive brush (right side of fence).



Assembling the diluent injector in Clean Energy Systems' gas generator (combustor and gas cooler).

WESTCARB Large-Volume Geologic Field Validation Test

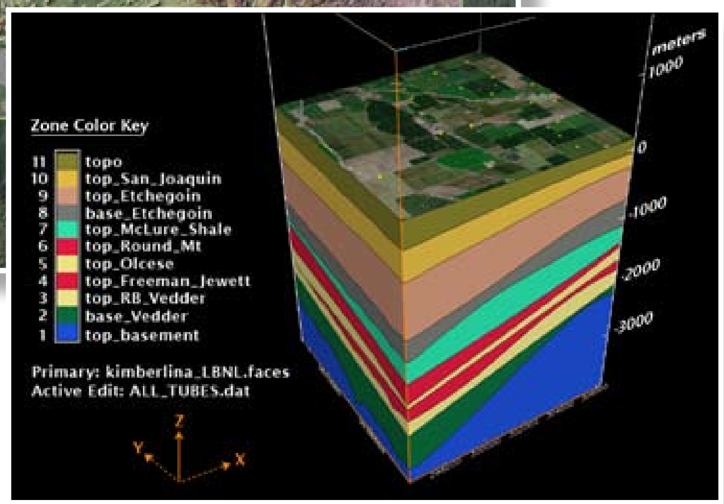
WESTCARB is preparing to inject 0.9 million metric tons (1 million tons) of CO_2 to validate the secure, large-volume storage capability of the saline formations prevalent in the Central Valley of California. Storage operations will be conducted in parallel with a commercial demonstration of a "rocket engine" oxy-combustion power plant with CO_2 capture by Clean Energy Systems.

The Kimberlina project site, located 29 km (18 mi) north of Bakersfield, currently houses Clean Energy Systems' 5 MW oxy-combustion pilot unit, which was funded in part by DOE and the California Energy Commission. Clean Energy Systems is ready to build a 49 MW power plant that could be the prototype for commercial clean power projects in the United States and Europe.

Starting in 2011 and continuing for four years, the entire CO_2-rich exhaust stream from the new power plant will be compressed to a liquid-like "supercritical" state and injected ~2,100 m (~7,000 feet) beneath the site. The test will allow researchers to better determine the storage opportunities in the saline formations of California's Central Valley, which are one of the largest potential CO_2 storage resources in WESTCARB's territory.

Two sandstone units are suitable candidates, and the deeper of the two—the Vedder—is currently the primary injection target. Its thickness at the site is up to 500 ft (150 m) and it is believed to have good injectivity. Both candidate units are regionally continuous, with thick shale units providing good overlying seals at the site and surrounding areas.

Throughout the project, WESTCARB researchers will deploy multiple monitoring and modeling methods, including proven oil industry techniques and new research-grade instruments to monitor the injected CO_2 as it is distributed underground. Results will be compared with computer models that simulate underground behavior of the CO_2, allowing for the validation and improvement of modeling techniques, which can subsequently be applied to potential commercial projects in the area. Researchers will continue to monitor the site after the conclusion of injection operations as part of the environmental stewardship phase of the project.



Initial geomodel developed by Lawrence Livermore National Laboratory for the formations underlying the Kimberlina Site.

The technical information and experience gained from the Kimberlina project will allow researchers to better quantify the storage potential of the Region's saline formations and will help policymakers and the public assess the role that industrial CO_2 capture and geologic sequestration can play in achieving greenhouse gas emission reductions.

Commercial Opportunities for CCS in the WESTCARB Region

A strong commitment to mitigating climate change is evidenced within the WESTCARB Region. Some WESTCARB states have policies to lower greenhouse gas emissions, and most are active in various climate change initiatives and in efforts to spur clean energy technology development. As the Western Region strives to meet emission targets in the coming years, commercial deployment of geologic and terrestrial carbon sequestration stands to become increasingly important.

With this setting in mind, WESTCARB has sited its geologic field tests in areas suitable for commercial deployment of CCS. This involves consideration of the potential storage capacity of geologic formations, their proximity to major sources, and possible economic co-benefits such as ECBM production, EOR, and EGR.

For example, WESTCARB has studied the potential for CO_2 storage in the depleting oil and natural gas fields in California's Central Valley. Enhanced recovery techniques are already being deployed in many of these fields, and even greater recovery rates may be realized through injection of CO_2. Recently, two power generators have announced plans to build plants with CO_2 capture in Kern County, and it is anticipated that CO_2 EOR will receive a boost once local supplies of CO_2 become available.

Biofuel plants may also provide a readily captured source of CO_2 in the Central Valley. Several have been proposed in response to California's Low-Carbon Fuel Standard.

California's Central Valley and Washington's Puget Sound contain the largest known saline formation storage potential in the WESTCARB region. The goal of WESTCARB's Large-Volume Geologic Storage Test in Kern County is to validate the storativity of a typical Central Valley saline formation at a scale that will demonstrate how a commercial operation would function.

WESTCARB examined the Pacific Coal Region in Washington to identify areas with the potential for ECBM production. More detailed characterization of CO_2 storage resource estimates for coal-bearing sub-basins in the Puget Sound in Washington is still being carried out. ECBM in this area could be facilitated by the proximity of a major stationary source for CO_2.

Fuels removed from forests and brushlands to help prevent catastrophic wildfires can be used by biomass power plants to generate electricity.

The western region affords significant potential for increased terrestrial carbon sequestration, and WESTCARB has been working with state entities in Oregon and California to develop protocols for terrestrial carbon sequestration projects. Research into the costs and carbon storage rates associated with afforestation, forest conservation, and forest fuels reduction to prevent catastrophic wildfires helps lay the groundwork for the introduction of these types of projects into carbon credit markets. Fuels removed from forests can also be used for biomass electricity generation, thereby decreasing fossil fuel consumption.

CO_2 Stationary Source Emission Estimation Methodologies Summary

APPENDIX A

Prepared for

U.S. Department of Energy
National Energy Technology Laboratory
Carbon Sequestration Program

Prepared by

Capture and Transportation Working Group
of the DOE Regional Carbon Sequestration Partnerships

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Contents

Introduction

The following summarizes the calculations, emissions factors, and databases employed by the Regional Carbon Sequestration Partnerships with respect to carbon dioxide (CO_2) stationary source emissions estimation methods. Tables of information are used to summarize the methodology. The CO_2 stationary sources include power plants, ethanol plants, petroleum and natural gas processing facilities, cement and lime plants, agricultural processing facilities, industrial facilities, iron and steel production facilities, and fertilizer-producing facilities. Estimation methods include databases and emissions factors. Each table lists the databases and emissions factors utilized for the particular CO_2 source type. The legend following each table contains the definitions for equation variables.

The documents used to identify each CO_2 stationary source, as well as the practical quantitative method (i.e., emission factors, continuous emissions-monitoring results, emission estimate equations, etc.) used to estimate CO_2 emissions from that source, are listed in the "CO_2 Emissions Methodology References" section of this report. These documents are organized by the reference numbers shown after the main text of each entry. The data sources to determine specific plant capacities, production outputs, or fuel usage data are listed by partnership in the "Data References by Partnership and Industry" section of this report.

Approach

The approach to determine these methodologies was to first identify significant CO_2 emission sources within each region, second to assess the availability of CO_2 emission data or to apply an estimate of the CO_2 emissions based upon sound scientific and engineering principles. In each partnership, the emissions were grouped by emission source and a methodology was established for each emission source category; then the methodology was utilized to estimate the CO_2 emissions from each emission source category. To summarize these efforts, nine tables containing CO_2 emission estimation methodology and equations for the major CO_2 stationary source industries outlined in the *Carbon Sequestration Atlas of the United States and Canada* have been created. Each regional carbon sequestration partnership is responsible for developing greenhouse gas (GHG) emission inventories and stationary source surveys within their respective partnership boundary area. More than 4,365 stationary sources have been documented for the seven partnerships.

Stationary sources fall under one of the nine industry types outlined by the Atlas. Table I-1 identifies the variety of stationary sources falling under any given industry type as identified by the *Atlas.*

Table I-1. CO_2 Stationary Sources by Industry Category

Industry Type	CO_2 Stationary Sources Included
Electric-Generating Plants	Coal, Oil, and Natural Gas-Fired Power Plants
Ethanol Production Plants	Ethanol Plants, Regardless of Feedstock Type
Agricultural Processing Facilities	Sugar Production
Natural Gas Processing Facilities	Natural Gas Processing Facilities
Industrial Facilities	Aluminum Production Facilities, Soda Ash Production Facilities, Glass Manufacturing Facilities, Automobile Manufacturing Facilities, Compressor Stations, Iron Ore Processing Facilities, Paper and Pulp Mills
Iron and Steel Facilities	Iron and Steel Producing Facilities
Cement and Lime Plants	Lime Production Facilities, Cement Plants
Refineries and Chemical Facilities	Petroleum Refinery Processing, Ethylene Production Facilities, Ethylene Oxide Production, Hydrogen Production Facilities
Fertilizer Production	Ammonia Production

CO_2 Estimation Methodology

For any stationary source within a given industry type, the regional partnerships employed CO_2 emissions estimate methodologies that are based on the most readily available representative data for that particular industry type within the respective partnership area. CO_2 emissions data provided by databases (for example, eGRID, ECOFYS, or NATCARB) were the first choice for all of the regional partnerships both for identifying major CO_2 stationary sources and for providing reliable emission estimations. Databases are considered to contain reliable and accurate data obtained from direct emissions measurements via continuous emissions monitoring (CEM) systems. One drawback of formal databases can be the delay between data collection and publication, but this does not present a significant problem for the partnerships as the dates of information are clear. When databases were not available, stationary source facility production or fuel usage were coupled with CO_2 emissions factors to estimate annual CO_2 emissions from the production or fuel usage data. Emissions factors, fuel usage data, and facility production data were obtained from various databases, websites, and publications. Stationary source spatial location data (latitude and longitude), were determined from a variety of sources. Some databases (eGRID) contain latitude and longitude information for each stationary source. Where spatial location information was not available through an emissions database, other spatial location methods were utilized. These include the use of mapping tools (Google Earth, TerraServer, and USGS Digital Orthophoto Imagery) equipped with geospatially-defined data, along with web-based databases (Travelpost) containing latitude and longitude information for various U.S. locations.

Table 1. Methodology for Estimating CO_2 Emissions from Electric-Generating Plants

Methodology	Description
Database	The most current data were used where available. Actual emissions data were obtained from various databases even if not all sources had the same vintage data. These include: • EPA Clean Air Markets Division Facility Emissions Data (accessed 2006 via NATCARB), where the average of the most recent four years of data were selected and aggregated to the plant level, and the lowest values were dropped to reduce the impacts of startup and maintenance.[1] • EPA eGRID Database (2004)[2] • EPA Acid Rain Program Emission Report for 2005 (2006)[3] • Commission for Environmental Cooperation Website (U.S. Plants)[4] • Commission for Environmental Cooperation Website (Canadian Plants) (2002)[5] • Website for Canadian Sources;[6] new plant data from EIA Table ES3; New and Planned U.S. Electric Generating Units by Operating Company, Plant and Month, 2007–2008.[7] • U.S. DOE – EIA Power Plant Database.[8]
Emissions Factors	Data were analyzed based on the IPCC (2006) greenhouse gases methodology using fuel consumption, a fuel-specific carbon coefficient, and the fuel-related fraction of carbon oxidized, similar to the following equation.[9] CO_2 emissions were also calculated via combustion based on fuel type and usage data provided by the Transfer Technology Network (TTN) Database: [10] $M_{CO_2} = \frac{3.664F_tC_{\%}D_F}{2000}$ (if liquid or gaseous fuel) $M_{CO_2} = 3.664C_{\%}F_t$ (if solid fuel)
	For new plants without CO_2 data, annual emissions were estimated by calculating megawatt hours from the plant capacity and 50% annual production for natural gas combined cycle or 20% for natural gas simple cycle. 1100 lb of CO_2 per MWh was approximated based on examination of natural gas plants in the eGRID data to estimate emissions at new plants.[2] $M_{CO_2} = \frac{1100P}{2000}$

Legend:

$C_{\%}$ = Carbon in the fuel (weight fraction) (Found in Appendix B of this report)

D_F = Fuel density (lb per gallon = liquid; lb per million scf = gas)

F_t = Fuel usage rate (depends on fuel type) (gallons per year = liquid; million scf per year = gas; tons per year = solid)

M_{CO_2} = Total CO_2 emissions (tons per year)

P = Annual plant generation (MWh)

Notes: The Emissions & Generation Resource Integrated Database (eGRID) is a comprehensive inventory of environmental attributes of electric power systems and has been the most widely used source for gathering CO_2 stationary source emissions by the partnerships. eGRID provides annual CO_2 emissions data reported from the Environmental Tracking System (Continuous Emissions Monitoring), rather than emissions factors based solely on production or heat input. In addition to emissions data, eGRID also provides facilities' latitude, longitude, primary fuel, annual heat input, and annual power generation.

Table 2. Methodology for Estimating CO_2 Emissions from Ethanol Plants

Methodology	Description
Database	Where available, actual emissions data were obtained from various databases. The most current data were used, even if not all sources had the same vintage data. These include: • e-GRID Spreadsheets[2] • NATCARB's Ethanol Plant Excel Worksheet (2006 data). [11] • Data cited from the Renewable Fuels Association within certain partnership areas[12,13] and contact with ethanol plant operators.
Emissions Factors	Process-related emissions:[14, 15,16, 17, 18] $M_{CO_2} = \frac{\Sigma(E_{g,f}\theta_{E,f})}{2000}$ Combustion emissions using natural gas: [14, 16, 19, 20] $M_{CO_2} = \frac{44E_g\left(\frac{39,000\ BTU}{gal}\right)\left(\frac{lbmol}{359\ ft^3}\right)}{2000\left(\frac{1000\ BTU}{ft^3}\right)}$ Combustion emissions using coal:[6, 12] $M_{CO_2} = \frac{0.039E_g\theta_{coal}}{2000}$
	CO_2 emissions based on fermentation (2.88 ktonne CO_2 per million gal. ethanol). Emissions factor converted to a lb CO_2 per gallon ethanol produced: [12, 21] $M_{CO_2} = \frac{6.34E_{g,f}}{2000}$

Legend:

θ_{coal} = CO_2 emissions factor for coal combustion (lb CO_2 per million Btu)

$\theta_{E,f}$ = CO_2 emissions factor for ethanol production by feedstock (lb CO_2 per gal ethanol): corn = 6.31 lb CO_2 per gal ethanol (MGSC), 6.6 lb CO_2 per gal ethanol (PCOR) and 6.624 lb CO_2 per gal ethanol (WESTCARB), corn/wheat = 6.15 lb CO_2 per gal ethanol and beverage waste = 5.05 lb CO_2 per gal ethanol (MGSC)

E_g = Ethanol production (gal ethanol/year)

$E_{g,f}$ = Ethanol production by feedstock (i.e. corn, corn and/or wheat, beverage waste) (gal per year)

M_{CO2} = Total CO_2 emissions (tons per year)

Table 3. Methodology for Estimating CO_2 Emissions from Agricultural Processing Facilities

Methodology	Description
Emissions Factors	For facilities where fuel usage is known (obtained from EPA TTN Database):[1, 2, 6, 22] $M_{CO_2} = \frac{3.664 F_t C_{\%} D_F}{2000}$ (if liquid or gaseous fuel) $M_{CO_2} = 3.664 C_{\%} F_t$ (if solid fuel) Sugar production combustion emissions:[1, 2, 6,22] $M_{CO_2} = \frac{3.664 F_t C_{\%} D_F}{2000}$ (if liquid or gaseous fuel) $M_{CO_2} = 3.664 C_{\%} F_t$ (if solid fuel) Sugar production CO_2 emissions from the calcination of limestone-dolomite:[1, 2, 22] $M_{CO_2} = 0.785 E_{Lime}$

Legend:

$C_{\%}$ = Carbon in the fuel (weight fraction) (Found in Appendix B of this report)

D_F = Fuel density (lb per gallon = liquid; lb per million scf = gas)

E_{Lime} = Lime production rate (tons per year)

F_t = Fuel usage rate (depends on fuel type) (gallons per year = liquid; million scf per year = gas; tons per year = solid)

M_{CO2} = Total CO_2 emissions (tons per year)

Table 4. Methodology for Estimating CO_2 Emissions from Natural Gas Processing Facilities

Methodology	Description
Emissions Factors	Petroleum or natural gas processing facilities CO_2 emissions based on fuel usage data and energy content: [23] $M_{CO_2} = \beta F_t \theta_{fuel}$
	Natural gas processing emissions based on production (20% CO_2 content):[7] $M_{CO_2} = 4{,}238 F_{CH_4}$
	Natural gas sweetening process emissions based on fuel combustion needed to provide heat to regenerate the amine sorbent: [1, 6, 22] $M_{CO_2} = \frac{44.01\, F_{CH_4}}{2000\left(\frac{379\ ft^3}{lbmol}\right)}$
	Emissions based upon recovery from natural gas with a 4% average inlet gas CO_2 concentration and 1% average outlet gas CO_2 concentration: [24, 25] $M_{CO_2} = 608 E_{NG}$

Legend:

θ_{fuel} = CO_2 emissions factor based on heat input rate (tons CO_2 per million BTU)

E_{NG} = Natural gas processing rate (million scf per day)

F_{CH4} = Natural gas usage rate (standard cubic feet per year)

F_t = Fuel usage rate (depends on fuel type) (kgal per year = liquid; million scf per year = gas; tons per year = solid)

M_{CO2} = Total CO_2 emissions (tons per year)

β = Heat content of fuel used (million BTU per million scf [gas]; million BTU per ton [solid]; million BTU per kgal [liquid])

Table 5. Methodology for Estimating CO_2 Emissions from Industrial Facilities

Methodology	Description
Emissions Factors	Aluminum production emissions:[26, 27, 28, 29] $M_{CO_2} = E_A \theta_{A1,A2}$ Emissions from aluminum production (based on EPA AP-42 emissions factors):[30] $M_{CO_2} = \frac{3{,}080 E_A}{2000}$ Soda ash production combustion emissions were determined from fuel use data obtained from the USEPA's NEI (1999) Database. Fuel use data were used with a default emissions factor for specific fuels to convert fuel consumed to metric tons of CO_2 produced.[31, 32] $M_{CO_2} = F_t \theta_f$ Soda ash production emissions were based on stoichiometric relationship between trona ($Na_3HCO_3(CO_3)_2{\cdot}2H_2O$) and soda ash ($Na_2CO_3$):[31,32,33] $M_{CO_2} = 0.09737\, E_T$ (based on Trona production) $M_{CO_2} = 0.1383\, E_{SA}$ (based on Soda ash production)
	Glass container manufacturing emissions:[34] $M_{CO_2} = 160.16\, E_g$ Flat glass manufacturing emissions:[34] $M_{CO_2} = 180.69\, E_g$ Pressed and brown glass manufacturing emissions:[34] $M_{CO_2} = 112.93\, E_g$ Compressor station emissions based on heat input of natural gas:[30] $M_{CO_2} = \frac{8760\, \beta_{NG}(110 F_{NG})}{2000}$ Compressor station emissions based on NO_x emissions (when heat input is not available):[30] $M_{CO_2} = \frac{110\, C_{NO_x}}{\theta_{NO_x}}$ Autos manufacturing emissions:[35, 36] $M_{CO_2} = \frac{8760\, F_L(110\beta_{NG} + 146\beta_{diesel} + 214\beta_{coal})}{2000}$
	Paper production and combustion emissions based on fuel burned:[1, 6, 22] $M_{CO_2} = \frac{3.664\, F_t C_{\%} D_F}{2000}$ (if liquid or gaseous fuel) $M_{CO_2} = 3.664\, C_{\%} F_t$ (if solid fuel) Iron ore processing emissions:[30] $M_{CO_2} = 0.0155\, E_{Fe}$

Legend:

$\theta_{A1,A2}$ = CO_2 emissions factor for aluminum production based on the reduction technology implemented (Prebaked (A1) = 1.6 tons CO_2 per ton Al; Søderberg (A2) = 1.7 tons CO_2 per ton Al)

θ_f = CO_2 emissions factor for fuel usage based on fuel type (tons CO_2 per ton fuel = solid; tons CO_2 per gallon fuel = liquid)

θ_{NOx} = NO_x emissions factor based on heat input (lb NO_x per million Btu)

$C_{\%}$ = Carbon in fuel (weight fraction) (Found in Appendix B of this report)

C_{NOx} = NO_x emissions rate (tons per year)

D_F = Fuel density (lb per gallon = liquid; lb per million scf = gas)

E_A = Aluminum production rate (tons per year)

E_C = Clinker manufacture production (tons per year)

E_{Fe} = Iron ore production (tons pellet per year)

E_g = Glass manufacturing production (tons per day)

E_{SA} = Soda ash production rate (tons per year)

E_T = Trona production rate (tons per year)

F_L = Autos manufacturing loading factor (use 0.8 when data not available)

F_{NG} = Compressor loading factor (use 0.6 when data not available)

F_t = Fuel usage rate (depends on fuel type) (gallons per year = liquid; million scf per year = gas; tons per year = solid)

M_{CO2} = Total CO_2 emissions (tons per year)

β_{coal} = Maximum coal heat input rate (million Btu per hr)

β_{diesel} = Maximum diesel fuel heat input rate (million Btu per hr)

β_{NG} = Maximum NG heat input rate (million Btu per hr)

Table 6. Methodology for Estimating CO_2 Emissions from Iron and Steel Facilities

Methodology	Description
Emissions Factors	Emissions from iron and steel manufacturing: [37, 38, 39] $M_{CO_2} = 3.3E_{\varepsilon} + 0.02(3.667E_{pig}) + 0.004(3.667E_{SS}) + \theta_{EAF}E_{EAF}$ Iron and steel production emissions factors: [40] General steel production: $M_{CO_2} = 1.27\,E_S$ Use of an electric arc furnace: $M_{CO_2} = E_{EAF}\,\theta_{EAF}$

Legend:

θ_{EAF} = CO_2 emissions factors for electric arc furnace (MGSC: 0.0044 tons CO_2 per ton EAF steel; SECARB: 0.14 tons CO_2 per ton EAF steel)

E_{EAF} = EAF steel production rate (tons per year)

E_{pig} = Pig iron production rate (tons per year)

E_S = Steel production rate (tons per year)

E_{SS} = Scrap steel consumption rate (tons per year)

E = Coke usage (tons per year)

M_{CO2} = Total CO_2 emissions (tons per year)

Table 7. Methodology for Estimating CO_2 Emissions from Cement and Lime Plants

Methodology	Description
Database	Where available, CO_2 emissions taken from NATCARB Cement Database (2006).[24] Lime plants identified by USGS Mineral Industry Surveys. [41]
Emissions Factors	Process related emissions based on clinker production and estimated generation of cement kiln dust (CKD):[39, 42] $M_{CO_2} = (1 + C_{Dust})\,E_C\,\theta_C$ Combustion related emissions based on clinker production:[39, 42, 43] $M_{CO_2} = 0.463\,E_C$ Emissions from lime production:[39, 43, 44] $M_{CO_2} = 0.75\,E_{QL} + 0.87\,E_{DL}$
	Process emissions:[47] $M_{CO_2} = (1 + C_{Dust})\,E_C\,\theta_C$ Combustion emissions based on clinker production:[43, 46, 46b] $M_{CO_2} = 0.575\,E_C$ Lime (clinker) production emissions (from lime production reaction stoichiometry): $M_{CO_2} = 0.785\,E_C$
	Lime production combustion emissions:[23, 32] $M_{CO_2} = \beta F_t \theta_{fuel}$ Lime production process emissions:[23, 32] $M_{CO_2} = 0.75\,RE_{Lime}$
	CO_2 emissions from cement plants were generated based on cement produced, clinker content, amount of raw materials used and CO_2 emitted from combustion.[48] $M_{CO_2} = 0.9\,E_{CP}$

Legend:

θ_C = CO_2 emissions factor for clinker production (MGSC: 0.507 ton CO_2 per tonne clinker; PCOR: 0.536 ton CO_2 per ton clinker)

θ_{fuel} = CO_2 emissions factor based on heat input rate (tons CO_2 per million BTU)

C_{Dust} = Fraction of cement kiln dust (Assume 2% if no other data is available)

E_C = Clinker production rate (tons per year)

E_{CP} = Cement production rate (tons per year)

E_{DL} = Dolomite lime production rate (tons per year)

E_{Lime} = Lime production rate (tons per year)

E_{QL} = Quicklime production rate (tons per year)

F_t = Fuel usage rate (depends on fuel type) (kgal per year = liquid; million scf per year = gas; tons per year = solid)

M_{CO2} = Total CO_2 emissions (tons per year)

R = content of CaO in lime produced (EPA estimates 0.95 for high calcium lime)

β = Heat content of fuel used (million BTU per million scf (gas); million BTU per ton (solid); million BTU per kgal (liquid)).

Table 8. Methodology for Estimating CO_2 Emissions from Refineries and Chemical Facilities

Methodology	Description
Emissions Factors	Refinery processing emissions based on plant production :[49] $M_{CO_2} = E_P \theta_P$
	The combustion CO_2 emission rate was estimated for each fuel within each Petroleum Administration for Defense District (PADD) by multiplying the fuel usage rate (unit volume per yr) for each PADD with the CO_2 emission coefficient (lb CO_2 per unit volume). The total CO_2 emission rate was determined by summing the CO_2 emission rates for all fuels. An emissions factor (tons CO_2 per barrel per calendar day) was then calculated for each of the PADDs by dividing the total CO_2 emission rate for the district by the refining capacity (barrels per calendar day) for the district. States in the PCOR Partnership region are represented in PADDs 2 and 4. The CO_2 emissions factors for PADDs 2 and 4 were estimated to be 11.00 and 11.84 tons CO_2 per barrel per calendar day, respectively. (Note: These values must be recalculated each year when new refinery statistics are issued.) As an example, calculation of an emissions factor for a refinery in North Dakota, an emissions factor of 11.00 tons CO_2 per barrel per calendar day of the major product was used to calculate the total combustion-related emissions as follows: [1, 6, 20, 22] $M_{CO_2} = 11E_P$
	Refinery emissions rate: [40] $M_{CO_2} = E_P \theta_P$ Ethylene production emissions: [40] $M_{CO_2} = 2.43 E_P E_e$ Ethylene oxide production emissions: [40] $M_{CO_2} = 0.51E_O$
	An estimated emissions factor based on plant capacity was generated and emissions are estimated as follows: [50] $M_{CO_2} = 0.025(0.9 E_P)$ CO_2 emissions for hydrogen (H_2) production were based on steam methane reforming (SMR) in which a hydrocarbon and water vapor are used to create H_2 and CO_2 as a byproduct governed by the following reaction: $CH_4 + 2H_2O = CO_2 + 4H_2$ This reaction implies that 0.25 volumes of CO_2 are produced per volume of H_2. Thus, emissions from hydrogen production are calculated as follows: [50, 51] $M_{CO_2} = \frac{44.01(0.25\ E_H)}{2000\left(\frac{379\ ft^3}{lbmol}\right)}$

Legend:

θ_P = CO_2 emissions factor for petroleum refinery production (MGSC: 11.44 tons CO_2 per year per barrel per day petroleum; SECARB: 9.9 tons CO_2 per year per barrel per day of petroleum processed)

$C_{\%}$ = Carbon in fuel (weigh fraction) (Found in Appendix B of this report)

D_F = Fuel density (lb per gallon = liquid; lb per million scf = gas)

E_{et} = Ethylene production (tons per year)

E_H = H_2 production (scf per year)

E_O = Ethylene oxide production rate (tons per year)

E_P = Petroleum plant production rate (barrels per day)

F_{CH4} = Natural gas usage rate (standard cubic feet per year)

F_t = Fuel usage rate (depends on fuel type) (gallons per year = liquid; million scf per year = gas; tons per year = solid)

M_{CO2} = Total CO_2 emissions (tons per year)

Table 9. Methodology for Estimating CO_2 Emissions from Fertilizer Production

Methodology	Description
Emissions Factors	Ammonia production emissions:[39, 52] $M_{CO_2} = E_{NH_3}(\theta_{NH_3} + \theta_{fuel})$
	Ammonia production emissions:[52, 53] $M_{CO_2} = E_{NH_3}\theta_{NH_3}$

Legend:

E_{NH3} = Ammonia production (tons NH_3 per year)

θ_{NH3} = CO_2 process emissions factor for ammonia production (PCOR: 1.15 tons CO_2 per ton NH_3; MGSC: 1.2 tons CO_2 per ton NH_3; SECARB: 1.13 tons CO_2 per ton NH_3)

θ_{fuel} = CO_2 combustion emissions factor (0.5 tons CO_2 per ton NH_3)

M_{CO2} = Total CO_2 emissions (tons per year)

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Appendix 2: Carbon Fraction of Various Fuels Used for Combustion

Fuel	%C, as received	Basic Fuel Units
Eastern Bituminous Coal[1]	72.7	tons
Subbituminous Coal[1]	50.6	tons
Lignite[1]	36.4	tons
Natural Gas[2]	74.9	million ft^3
Fuel Oil[3]	86.7	1000 gal
Municipal Solid Waste[4]	38.0	tons
Propane[2]	81.7	1000 gal
Biomass (wood and wood wastes)[4]	21.5	tons
Residual Oil[3]	86.9	1000 gal
Coke (derived from coal)[5]	86.0	tons
Gasoline[6]	85.5	1000 gal

Notes:

1. EERC Ultimate Analysis (Eastern Bituminous is a Pittsburgh No. 8 Seam, Powder River Basin subbituminous coal is a Cordero Rojo, and lignite is a Fort Union Lignite)
2. Direct Calculations (Natural Gas is CH_4 and Propane is $CH_3CH_2CH_3$)
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Methodology for Development of Geologic Storage Estimates for Carbon Dioxide

APPENDIX B

Prepared for

U.S. Department of Energy
National Energy Technology Laboratory
Carbon Sequestration Program

Prepared by

Capacity and Fairways Subgroup of the Geologic Working Group
of the DOE Regional Carbon Sequestration Partnerships

August 2008

Foreword

This document is an update to the 2006 “Methodology for Development of Carbon Sequestration Capacity Estimates” published in the *2007 Carbon Sequestration Atlas of the United States and Canada (Atlas I)*. This document describes the methodologies used to produce the geologic resource estimates for carbon dioxide (CO_2) storage in the *2008 Carbon Sequestration Atlas of the United States and Canada (Atlas II)*. The rationales presented were used to simplify assumptions for estimating the amount of CO_2 that can be stored in subsurface geologic environments of the United States and parts of Canada. The primary focus of *Atlas II* is to add additional basins and formations to the CO_2 storage portfolio, update information on the DOE’s Carbon Sequestration Program as well as the Regional Carbon Sequestration Partnerships (RCSPs), and provide definitions of CO_2 resource versus CO_2 capacity that reflect the uncertainty of geologic storage estimates for CO_2 across the RCSPs.

The RCSPs are charged with providing a quantitative estimate of the geologic storage resource for CO_2 in the subsurface environments of their regions. These estimates are required to indicate the extent to which carbon capture and storage (CCS) technologies could contribute to the reduction of CO_2 emissions into the atmosphere. This assessment is a high-level overview and is not intended as a substitute for site-specific assessment and testing. The methodologies described in this document were designed to integrate results of data compiled by the seven RCSPs for three types of geologic formations: saline formations, unmineable coal seams, and oil and gas reservoirs. These methodologies are developed to be consistent across North America for a wide range of available data. Results of this assessment are intended to be distributed by a geographic information system (GIS) and made available as hard-copy results in *Atlas II.*

This document is a consensus product resulting from discussions among researchers representing all seven RCSPs. A subcommittee, the Capacity and Fairways Subgroup, convened by the Geologic Working Group of the RCSPs in May of 2006 for development of *Atlas I*, provided leadership for this effort. Methods used by the RCSPs for estimating CO_2 storage potential in Atlas I were inventoried and reviewed to generate consistent assumptions for estimating the geologic resource for CO_2 in *Atlas II.* A workshop in Pittsburgh, Pennsylvania, on June 21, 2007, provided a venue for broader discussion within the Capacity and Fairways Subgroup; and additional discussions, via phone conference and e-mail, have led to development of consensus on the updated approach presented here.

Contents

Introduction

The purpose of this document is to outline procedures for estimating the geologic storage potential for carbon dioxide (CO_2) in the United States and Canada for three types of geologic formations: saline formations, unmineable coal seams, and oil and gas reservoirs. This document was used as part of the updated *2008 Carbon Sequestration Atlas of the United States and Canada (Atlas II)*. The primary focus of *Atlas II* is to add additional basins and formations to the CO_2 storage portfolio, update information on the DOE's Carbon Sequestration Program as well as the Regional Carbon Sequestration Partnerships (RCSPs), and provide definitions of CO_2 resource versus CO_2 capacity that reflect the uncertainty of geologic storage estimates for CO_2 across the RCSPs.

The methodologies presented for estimating geologic storage potential for CO_2 for this 2008 assessment consist of widely accepted assumptions about in-situ fluid distribution in porous media and fluid displacement processes commonly applied in the petroleum and ground water science fields. Data collected by the RCSPs were used to estimate the CO_2 storage quantities for Atlas II. Diverse data from three types of geologic formations in the subsurface are summarized, interpolated, averaged, or generalized by each of the seven RCSPs to calculate CO_2 storage potential. Methodologies for calculating shale and basalt formations' storage potential are currently under development and are not discussed in this methodology document.

Atlas II provides CO_2 ***resource*** estimates by state/province and RCSP. Methodologies presented in this document describe calculations and assumptions used for CO_2 **resource** estimates. 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. Economic or regulatory constraints are included in CO_2 ***capacity*** estimates. It should also be noted that for the development of specific commercial-scale geologic storage sites, economic and regulatory constraints must be considered to determine the portion of the CO_2 resource that is available under various development scenarios. Under the most favorable economic and regulatory scenarios, 100 percent of the estimated CO_2 **resource** may be considered CO_2 **capacity**.

Methods for estimating subsurface volumes are widely and routinely applied in petroleum, groundwater, underground natural gas storage, and Underground Injection Control disposal-related estimations. Therefore, the volumetric method is the basis for CO_2 resource calculations in *Atlas II*. The volumetric formula uses porosity, area, and thickness in a Monte Carlo simulation approach with various efficiency terms included to account for ranges of variations in the geologic volumetric properties and the fraction of the accessible pore volume that is most likely to be contacted by injected CO_2

Atlas II's assessment is intended to identify the geographical distribution of CO_2 resource for use in energy-related government policy and business decisions. It is 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 assessment does not include the criteria that are required to make these types of decisions. Similar to a natural resource assessment such as petroleum accumulations, this resource estimation is volumetrically based on physically accessible CO_2 storage in specific formations in sedimentary basins without consideration of injection rates, regulations, economics, or surface land usage.

CO_2 Resource Estimates

A CO_2 **resource** estimate includes all volumetric estimates of geologic CO_2 storage reflecting physical and chemical constraints or limitations (including potable water protection), but does not include current or projected economic constraints, regulations, or well and/or surface facility operations. Examples of physical constraints include isolation from potable waters, solubility of CO_2 in water, gravity segregation, injection formation fracture propagation pressure, caprock (or seal) capillary entry pressure, fracture propagation pressure, and displacement efficiency. Potable waters, for the purposes of *Atlas II*'s assessment, represent waters protected by the Safe Drinking Water Act (SDWA). Additional geologic-based physical constraints include vertical thickness, proportion of porosity available for CO_2 storage, and fraction of the total area accessible to injected CO_2. Examples of chemical constraints are CO_2-brine solubility, brine concentration with depth, dissolution rates of CO_2 into brine, and precipitation (or mineralization) effects.

CO_2 Capacity Estimates

Carbon dioxide **capacity** is the estimate of geologic storage with the highest degree of certainty with present economic and regulatory considerations included. Economic considerations include CO_2 injection rate and pressure, the number of wells drilled into the formation, types of wells (horizontal versus vertical), the number of injection zones completed in each well, operating expenses, and injection site proximity to a CO_2 source. In most cases, an indication of injectivity must be available from an existing well with adequate tests to indicate CO_2 injection rate directly or, at a minimum, in-situ permeability. In addition, sophisticated analysis of the potential for use of oil and gas reservoirs for CO_2 storage with enhanced oil recovery (EOR) and enhanced gas recovery (EGR) can be made when calculating CO_2 capacity. Examples of regulatory constraints include protection of potable water, minimum well spacing, maximum injection rates, prescribed completion methods (cased vs. open-hole), proximity to existing wells, and surface usage considerations. Appendices 1 and 2 include additional discussion of scenarios where economic and regulatory criteria may impact storage capacity estimates.

For a given CO_2 storage resource estimate for a specific site, different development scenarios affect the estimate of CO_2 storage capacity. Wellbore type, transportation, and injection pressure are just a few examples of different site considerations that may increase or decrease the CO_2 storage capacity of a geologic formation.

CO_2 Storage Classification

Classification of storage is not only necessary to understand the storage estimates in *Atlas II* but also to be able to establish terminology that can be used for making regulatory and business decisions. Furthermore, a classification system provides a comparable basis for assessing CO_2 resource and capacity and related market value in the future. If a CO_2 storage industry or market evolves, a classification system would assist in the following:

- Verifying tradable credits
- Advising government agencies on storage estimates
- Developing confidence in an open market for capacity
- Protecting correlative rights of the CO_2 capacity owners (pore space and/or adsorptive capacity)

Improving the accuracy of a CO_2 resource estimate does not necessarily mean changing the estimate but reclassifying the estimate to signify the increased confidence or lowered risk in the resource estimate. *Atlas II* has started this process by defining "CO_2 resource estimates" and "CO_2 capacity estimates."

The petroleum and coal industries have classification protocols that indicate level of certainty and reduced risks that require application of objective and subjective rules. For example, the petroleum industry uses "resource" and "reserve." Resource is much more uncertain than reserve, and as such, the petroleum industry has two divisions within resource: "speculative" and "contingent." Speculative is higher risk or lesser certainty, while contingent is relatively lesser risk or greater certainty. Contingent illustrates a degree of certainty in which plans and budgets are designated to drill wells and test a specific geologic formation. Speculative illustrates a degree of certainty where risk is too high to consider site development.

The petroleum industry's use of reserve also has two divisions: "proved" and "unproved." Reserves are considered commercial at current economic conditions by the owner company. Commerciality includes the ability to transport the oil to a market, e.g., the availability of a pipeline. Proved is the highest degree of certainty and requires actively producing wells that have either produced oil or have very strong test results showing that they will produce oil.

Because the CO_2 storage industry is in its infancy, there are very few active CO_2 injection wells providing site-specific information needed for reclassifying a "CO_2 resource" as "CO_2 capacity." However, it is expected that the needed data will evolve as the CO_2 storage industry matures.

Results and conclusions for Validation Phase Tests being conducted by the RCSPs are not completed for inclusion in *Atlas II*. The primary purpose of the Validation Phase Tests is to improve understanding of regional and local considerations for deployment of commercial scale geologic carbon capture and storage (CCS). Consequently, the size of the Validation Phase pilots relative to a basin may be too small to have any impact on changing the approximations or methodology for formation resource estimates for an entire basin that appears in a national atlas.

CO_2 Storage Calculation

Methods available for estimating subsurface volumes are widely and routinely applied in petroleum, ground water, underground natural gas storage, and the Underground Injection Control (UIC) disposal-related estimations. In general, these methods can be divided into two categories: static and dynamic. The static methods are volumetric (method used for *Atlas II*) and compressibility; the dynamic methods are decline curve analysis, material balance, and reservoir simulation.

While all methods are applicable after active injection, only the static methods are applicable prior to injection or collection of field-measured injection rates. These models rely on parameters that are directly related to the geologic description of the area for injection, e.g., thickness, porosity, and compressibility. After CO_2 injection, dynamic models are applicable. For a description of static and dynamic models for calculating CO_2 storage potential see Appendix 3.

It is beyond the scope of this assessment to adequately compare and contrast these methods, but as with other methodologies, some approaches are simple and require only a few parameters, while others methods require numerous input parameters.

Reporting

The RCSPs began by compiling data that were collected in their respective regions and submitting it to the National Carbon Sequestration Database and Geographical Information System (NATCARB). Polygons enclosing each area assessed with an attached database file (.dbf) were reported. In the database, a low and a high estimate of saline formation and coal CO_2 resource in metric tons of CO_2 were recorded for each polygon, with a low value and a high value generated using the low and high values of storage efficiency (E) provided in this document. Variability of E includes uncertainty in geologic parameters such as areal extent, thickness, and porosity. For storage in oil and gas reservoirs, a resource estimate in metric tons of CO_2 is calculated for each formation, play, or region, with individual or total oil and gas reservoir CO_2 storage potential displayed in a polygon. Data that support the calculated volumes are noted and archived by each RCSP.

Each RCSP provided a list of assumptions and calculation criteria that were used in their Region, as well as CO_2 resource estimates at the granularity level available. The criteria outlined in this document are considered the default settings; if a RCSP used other criteria, these are explicitly stated along with the rationale. In addition to basin totals, CO_2 resource estimates by geographic information system (GIS) grid cell were reported.

CO_2 Resource Map

A CO_2 resource map covering the United States and parts of Canada for each formation type was developed by the NATCARB for *Atlas II* from the information provided by the RCSPs.

These maps illustrate areas of potential CO_2 storage. For oil and gas reservoirs and saline formations, the maps illustrate reservoirs or formations with CO_2 storage potential that have had some degree of assessment. For coal seams, the maps illustrate (1) coal seams with CO_2 storage potential that have had some degree of assessment, and (2) coal seams that have been identified but not yet assessed for CO_2 storage potential.

Types of Geologic Environments

For the purposes of this assessment, the subsurface is categorized into five major geologic formations: saline formations, coal seams, oil and gas reservoirs, shale, and basalt formations. Each of these is defined and input parameters for CO_2 resource calculations are described below. Where possible, CO_2 resource has been quantified for saline, coal, oil, and gas, whereas shale and basalt formations are presented as future opportunities and not assessed in this document.

Saline Formation CO_2 Resource Estimating

Background: Saline formations are composed of porous rock saturated with brine and capped by one or more regionally extensive impermeable rock formations enabling trapping of injected CO_2. A saline formation assessed for storage is defined as a porous and permeable body of rock containing water with total dissolved solids (TDS) greater than 10,000 parts per million (ppm), which can store large volumes of CO_2. A saline formation can include more than one named geologic formation or be defined as only part of a formation.

This saline formation storage assessment includes the following assumptions: (1) saline formations are heterogeneous and therefore under multiphase conditions; (2) only 20 to 80 percent of the area inventoried and 25 to 75 percent of the formation thickness assessed would be occupied by CO_2; and (3) the efficiency factor accounts for net-to-effective porosity, areal displacement efficiency, vertical displacement efficiency, gravity effects, and microscopic displacement efficiency.

Reporting: For *Atlas II*, CO_2 resource estimates for saline formations were reported at the geologic basin level. Where basins straddle more than one region, one RCSP assumed primary responsibility for the basin, while the other RCSP provided the needed data in its portion of the basin.

Screening Criteria: Saline formations assessed for storage are restricted to those meeting the following basic criteria for the storage: (1) pressure and temperature conditions in the saline formation are adequate to keep the CO_2 in dense phase (liquid or supercritical); (2) a suitable seal is present to limit vertical flow of the CO_2 to the surface (caprock); and (3) a combination of hydrogeologic conditions isolates the CO_2 within the saline formation. These criteria also apply to existing UIC and other regulations, and are relevant to capacity assessment as well, but the criteria are first incorporated into resource assessments.

Depths: The storage of CO_2 in saline formations is limited to sedimentary basins with vertical flow barriers and depth exceeding 800 meters. Sedimentary basins include porous and permeable sandstone and carbonate rocks. The 800-meter cutoff is an attempt to select a depth that reflects pressure and temperature that yields high density liquid or supercritical CO_2. This is arbitrary and does not necessarily designate a lower limit of depth conducive to CO_2 storage. Several natural gas reservoirs exist at shallower depths; this infers that CO_2 gas may be stored at shallower depths but only at pressure and temperatures most likely to sustain gas-phase CO_2 density. Because of the large difference in density between liquid-phase and gas-phase CO_2, the additional storage of shallow saline formations is not anticipated to provide any substantial increase in resource estimates for *Atlas II*, but this could be considered in a site-specific assessment.

Caprocks: All sedimentary rocks included in the saline formation resource estimate must have caprocks (vertical seals) consisting of shale, anhydrite, and evaporites. Thickness of these seals is not considered in this assessment. For increasing confidence in a storage estimate (determining CO_2 capacity) other criteria including seal effectiveness (e.g. salinity and pressure above and below the caprock), minimum permeability, minimum threshold capillary pressure, and fracture propagation pressure of a caprock should be considered.

Computing CO_2 Resource: The volumetric method is the basis for CO_2 resource calculations in saline formations. The volumetric formula requires the injection total area (A_t), formation thickness (h), and porosity (Φ). A storage efficiency factor (E) is applied to this formula to reflect the volume accessible to injected CO_2. Monte Carlo simulations estimated a range of E between 1 and 4 percent of the total pore volume of saline formations for a 15 to 85 percent confidence range (for more information on E and Monte Carlo simulations see Appendix 4).

The volumetric equation for CO_2 resource calculation in saline formations with consistent units assumed is as follows:

$$G_{CO2} = A_t \, h_g \, \phi_{tot} \, \rho \, E$$

Parameter	Units*	Description
G_{CO2}	M	Mass estimate of saline formation CO_2 resource.
A_t	L^2	Geographical area that defines the basin or region being assessed for CO_2 storage calculation.
h_g	L	Gross thickness of saline formations for which CO_2 storage is assessed within the basin or region defined by A.
ϕ_{tot}	L^3/L^3	Average porosity of entire saline formation over thickness h_g or total porosity of saline formations within each geologic unit's gross thickness divided by h_g.
ρ	M/L^3	Density of CO_2 evaluated at pressure and temperature that represents storage conditions anticipated for a specific geologic unit averaged over h_g.
E**	L^3/L^3	CO_2 storage efficiency factor that reflects a fraction of the total pore volume that is filled by CO_2.

* L is length; M is mass.
**For details on E, please refer to Appendix 4.

Details of this calculation are determined by each RCSP.

Oil and Gas Reservoir CO_2 Resource Estimating

Background: Typical mature oil and gas reservoirs in North America have held crude oil and natural gas over millions of years. They consist of a layer of permeable rock with a layer of nonpermeable rock (caprock) above, such that the nonpermeable layer forms a trap that holds the oil and gas in place. Oil and gas fields have many characteristics that make them excellent target locations for geologic storage of CO_2. The geologic conditions that trap oil and gas are also the conditions that are conducive to long-term CO_2 storage.

As a value-added benefit, CO_2 injected into a mature oil reservoir can enable incremental oil to be recovered. A small amount of CO_2 will dissolve in the oil, increasing its bulk volume and decreasing its viscosity, thereby facilitating flow to the wellbore. Typically, primary oil recovery and secondary recovery via a water flood produce 30–40 percent of a reservoir's original oil-in-place (OOIP). EOR via a CO_2 flood allows recovery of an additional 10–15 percent of the OOIP.

Reporting*:* In *Atlas II*, CO_2 resource estimates for oil and gas reservoirs are reported at the oil or gas field level. An oil or gas field can contain numerous reservoirs, leases, and wells, but field level is a scale that is well defined both on a technical and regulatory basis. In addition, at the field level, data manipulation, storage, and access are surmountable tasks. The field level can easily be summed to provide estimates at the state or RCSP scales. It is also possible to cross-check storage estimates against readily available state/province and national production figures (e.g., Energy Information Administration [EIA] and state oil and gas commissions).

Screening Criteria: Carbon dioxide storage resource for oil or gas reservoirs for this assessment is defined as volumes of the subsurface that have hosted natural accumulations of oil and/or gas and could be used to store CO_2 in the future. Mapping of the seal to oil and gas formations is not required because the entrapment of oil or gas is considered evidence that a CO_2 containment seal is present, and the associated water is normally not potable. Production of oil and gas has demonstrated that pores within the produced area are interconnected and therefore can be accessed by CO_2. In some cases, pressure is depleted significantly as a result of production, which can be conceptualized as volumes that can be replaced by repressurizing these formations with CO_2. In addition, no distinction is made in this assessment for maturity of the field (i.e., fields that are or will soon become depleted or abandoned).

Depths: Because oil and gas fields can be productive across a wide variety of depths, no minimum or maximum depth was used for *Atlas II* CO_2 resource estimates. Only oil and gas fields with a water TDS concentration of 10,000 ppm and higher were included, unless specifically noted and justified. The water quality in oil and gas fields is very likely to be classified as non-potable due to oil and gas contamination.

Computing CO_2 Resource: Storage volume methodology for oil and gas fields was simplified for *Atlas II*. The calculation was based on quantifying the volume of oil and gas that could be produced and assuming that it could be replaced by an equivalent volume of CO_2, where both oil and gas and CO_2 volumes are calculated at initial formation pressure or a pressure that is considered a maximum CO_2 storage pressure. Two main methods were used to estimate the CO_2 storage volume: (1) a volumetrics-based CO_2 storage estimate and (2) a production-based CO_2 storage estimate. The method used for *Atlas II* was selected by each RSCP based on available data. The two methods have storage efficiency factors built into their respective methodologies. No range of CO_2 storage values is proposed for oil and gas fields, indicating a relatively good understanding of volumetrics of these systems.

Volumetrics-based CO_2 storage estimate for oil and gas formations: The volumetrics-based CO_2 storage estimate is a standard industry method to calculate OOIP or original gas in place (OGIP). OOIP is calculated by multiplying formation area (A), net oil column height (h_n), average effective porosity (ϕ_e), and oil saturation (1 - water saturation as a fraction [S_w]). A formation-specific fraction of OOIP is estimated to be accessible to CO_2; the fraction can include multiple mechanisms, such as dissolution of CO_2 in situ into oil and water. This fraction is defined as the CO_2 storage efficiency factor (E) and can be derived from local experience or reservoir simulation. For site-specific studies, formation volumetrics involving gas require consideration of pressure and formation drive mechanism. Because of previous extensive experience in estimating volumetrics of formations, regional, play, or formation-specific values supplied by each RCSP are used.

The general form of the volumetric equation being used in this assessment is similar to that used from saline formations, except that E involves original oil or gas in place:

$$G_{CO2} = A\, h_n\, \phi_e\, (1\text{-}S_w) B\, \rho\, E$$

Parameter	Units*	Description
G_{CO2}	M	Mass estimate of oil and gas formation CO_2 resource.
A	L^2	Area that defines the oil or gas formation that is being assessed for CO_2 storage calculation.
h_n	L	Oil and gas column height in the formation.
ϕ_e	L^3/L^3	Average porosity over net thickness h_n or effective porosity of formation divided by h_n.
S_w	L^3/L^3	Average water saturation within the total area (A) and net thickness (h_n).
B	L^3/L^3	Formation volume factor; converts standard oil or gas volume to subsurface volume (at formation pressure and temperature). B = 1.0 if CO_2 density is evaluated at anticipated reservoir pressure and temperature
ρ	M/ L^3	Density of CO_2 evaluated at pressure and temperature that represents storage conditions in the formation averaged over h_n.
E	L^3/L^3	CO_2 storage efficiency factor that reflects a fraction of the total pore volume from which oil and/or gas has been produced and that can be filled by CO_2.

* L is length; M is mass.

Production-based CO_2 storage estimate for oil and gas formations: A production-based CO_2 storage estimate is possible if acceptable records are available on volumes of oil and gas produced. Produced water is not considered in the estimates, nor is injected water (waterflooding), although these volumes may be useful in site-specific calculations. In cases where a field has not reached a super-mature stage, it is beneficial to apply decline curve analysis (described in Appendix 3) to generate a better estimate of estimated ultimate recovery (EUR), which represents the expected volume of produced oil and gas (Li and Home, 2003).

It is necessary to apply an appropriate formation 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 formation is included. No area, column height, porosity, residual water saturation, or estimation of the fraction of OOIP that is accessible to CO_2 is required because production reflected these formation characteristics. If data are available, it is possible to apply efficiency to production data to convert it to CO_2 storage volumes; otherwise replacement of produced oil and gas by CO_2 on a volume-for-volume basis (at formation pressure and temperature) is accepted.

Simplifying assumptions for oil and gas fields: Examples of factors not explicitly considered in the production-based method that might increase the potential CO_2 storage volume that could be stored include miscibility of CO_2 into oil, dissolution of CO_2 into residual and associated water, mineral trapping, and pressure decline as a result of production. Parameters not considered that may limit the CO_2 volume that can be stored include imperfect inversion of processes that occurred during production—for example, replacement of produced oil or gas by water (CO_2 may not completely replace this imbibed water), production of gas by solution gas drive, and waterflooding. In addition, it may not be realistic to assume that the volume of CO_2 stored is equivalent to the volume of originally trapped oil and gas because of pressure perturbations of the formation during production (for example, compromise to the seal by well penetration or by deformation during production). It is also not realistic to assume the seal will respond in the same manner to trapped CO_2 as to the oil and gas originally in place.

Coal Seam CO_2 Resource Estimating

Background: Carbon dioxide storage opportunities exist within coal seams. All coals have varying amounts of methane adsorbed onto pore surfaces, and wells can be drilled into unmineable coalbeds to recover this coalbed methane (CBM). Initial CBM recovery methods, such as dewatering and depressurization, leave a considerable amount of methane in the formation. Additional recovery can be achieved by sweeping the coalbed with CO_2. Depending on coal rank, as few as three to as many as thirteen molecules of CO_2 may be adsorbed for each molecule of methane released, thereby providing an excellent storage site for CO_2 along with the additional benefit of enhanced coalbed methane (ECBM) recovery.

Reporting: For *Atlas II*, CO_2 resource estimates for coal are reported at the geologic basin level. Where basins straddle more than one region, one RCSP assumed primary responsibility for the basin, while the other RCSP provided the needed data in their portion of the basin.

Screening Criteria:
Depths: The vertical intervals included are between a minimum and maximum depth. The minimum depth was dictated by a water-quality standard to ensure that potentially potable water-bearing coals are not included; only coal seams with a water TDS concentration of 10,000 ppm and higher are included. Where water quality data are scarce or unavailable, analogy to other basins was used to estimate the minimum depth criteria.

Mineability: Within the depth intervals selected for a particular basin, a determination is being made as to which coals are unmineable, based upon today's standards of technology and profitability. This criteria implies the use of economic constraints for this coal storage assessment; however, use of this constraint is necessary because of safety and regulatory concerns for mining coal that has been used to store CO_2. While there will clearly be advancements in mining technology and changes in the value of the commodity in the future, which will enable some of the coal seams deemed unmineable today to be mineable in the future, it is beyond the scope of this effort to forecast those developments and their impact. Depth, thickness, and coal quality (e.g., coal rank, sulphur content, etc.) criteria are established for each basin for this purpose. Only those coals deemed unmineable (with today's technology) are included in this CO_2 resource estimate. If such data are available, any coal reserve is also excluded.

Computing CO_2 Resource: Carbon dioxide resource estimates for coal used a GIS approach with a minimum grid cell size of 10 km x 10 km. A volumetric approach is applied, using the prevailing pressure gradient for each basin (or 0.433 psi/ft if it is unknown), and a (dry, ash-free) CO_2 adsorption isotherm at an "average" formation temperature. In-situ storage volumes are computed after correcting for ash content. If data are available, different isotherms for different coal ranks are used. If no CO_2 isotherm is available, isotherms from similar coal ranks in analog basins are used. No accounting for decreasing CO_2 storage potential at increasing temperatures (depths) is taken.

The volumetric equation with consistent units applied for coal CO_2 storage potential follows:

$$G_{CO2} = A\ h_g\ C\ \rho_s\ E$$

Parameter	Units*	Description
G_{CO2}	M	Mass estimate of CO_2 resource of one or more coal beds.
A	L^2	Geographical area that outlines the coal basin or region for CO_2 storage calculation.
h_g	L	Gross thickness of coal seam(s) for which CO_2 storage is assessed within the basin or region defined by A.
C	L^3/ L^3	Concentration of CO_2 standard volume per unit of coal volume (Langmuir or alternative); assumes 100% CO_2 saturated coal conditions; if on dry-ash-free (daf) basis, A and h must be corrected for daf.
ρ_s	M/ L^3	Standard density of CO_2.
E**	L^3/L^3	CO_2 storage efficiency factor that reflects a fraction of the total coal bulk volume that is contacted by CO_2.

* L is length; M is mass.
**For details on E, please refer to Appendix 5.

The CO_2 storage efficiency factor has several components that reflect different physical barriers that inhibit CO_2 from contacting 100 percent of the coal bulk volume of a given basin or region. Depending on the definitions of area, thickness, and CO_2 concentration (from Langmuir isotherms), the CO_2 storage efficiency factor may also reflect the volumetric difference between bulk volume and coal volume. For example, if *A* and *h* are based on dry-ash-free (daf) conditions, *C* must have a *daf* basis too. Additionally, because gross thickness is used in the equation above, E includes a term that adjusts gross thickness to net thickness. (Additional information on E for coal seams appears in Appendix 5.)

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Appendices

Appendix 1: Storage Development Scenarios Affecting CO_2 Storage Estimates – *by Scott Frailey*

For a given CO_2 storage resource estimate for a specific site, different development scenarios affect the estimate of CO_2 storage capacity. Wellbore type, transportation, and injection pressure are just a few examples of different site considerations that may increase or decrease the CO_2 storage capacity of a geologic formation.

Wellbore Type

Horizontal and vertical wells are two types of injection wells that could be considered for a storage site. In general, horizontal wells are expected to have a higher injection rate (tons per day) capability, especially in geologic formations with relatively small vertical thickness. Consequently, for a given CO_2 injection rate, fewer horizontal wells would be required as compared to the number of vertical wells. Fewer drilled wells also result in less impact at the surface.

For geologic formations that are compartmentalized horizontally, a horizontal well is more likely to attain a higher CO_2 storage capacity compared to a vertical well. Similarly, a geologic formation with vertical flow barriers is more likely to have relatively higher CO_2 storage capacity from injecting into vertical wells.

The decision to use horizontal or vertical wells has economic tradeoffs in terms of the number of wells, injection rate, and acquisition of surface acreage for well locations. Moreover, the effect of wellbore type on CO_2 capacity will vary based on the geologic formation. The storage capacity estimate in this example will be different for the well type, but the storage resource available would be the same (unless the drilled wells provided information that increased or decreased the resource estimate).

Transportation of CO_2

In most cases, a pipeline of some distance will be required to link the emission source and the injection site. Pipelines may be on the order of $1 million per mile. A tradeoff between a closer injection site with lesser subsurface CO_2 storage capacity may be economically acceptable compared to the increased capital investment of a longer pipeline to a storage site with higher storage capacity. Likewise, a closer site that requires a greater number of wells, more expensive wells, or deeper wells may be much more economical compared to a geologic formation with fewer, less expensive wells that requires a 10-mile pipeline.

An estimate of CO_2 resource is not affected by the distance between source and sink and gives an estimate of the accessible pore volume regardless of the proximity to an existing or proposed CO_2 emission source.

Injection Pressure

All geologic formations have a threshold pore pressure that will begin to propagate a fracture within the injection formation if exceeded. Some caprocks withstand this pressure and the fracture terminates at the caprock. Many relatively thick shales constrain the growth of a fracture; however, in addition to a threshold fracture pressure, shales have a capillary pressure threshold that if exceeded, will breech and allow an injected fluid to pass through it.

Every formation (reservoirs and caprocks) has a pressure threshold that must be included in site-specific CO_2 capacity estimates. However, this pressure constraint can be managed during the planning and operation stages of development and should not influence the CO_2 resource estimate. A storage site with limited injection and/or pore pressure may reduce the CO_2 capacity, but due to the number of injection wells required or length of pipeline, it may be economically the best choice. Moreover, drilling more wells can reduce the injection pressure into each well and keep reservoir pressure lower. Horizontal wells tend to have lower injection pressure as compared to vertical wells. Additionally, similar to natural gas storage, if regulations and economics are favorable, water production wells can be used to reduce pressure and increase capacity at a particular storage site.

All of these seemingly technical considerations have economic or regulatory components that must be considered. For a site-specific capacity assessment, technical, economic, and regulatory aspects must be considered collectively for the time and duration of the storage project. It is important to note that capacity estimates are dynamic and may change with new regulations, storage technology, or economic conditions. Additionally, new and different information found from characterization of new wells or application of new technology to existing wells can change resource and capacity estimates.

Appendix 2: Injectivity, Regulations, and Economics for CO_2 Storage Estimates - *by Scott Frailey*

Atlas II's assessment is intended to identify the geographical distribution of CO_2 resource for use in energy-related government policy and business decisions. It is 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 assessment does not include the criteria that are required to make these types of decisions. Similar to a natural resource assessment such as petroleum accumulations, this resource estimation is volumetrically based on physically accessible CO_2 storage in specific formations in sedimentary basins without consideration of injection rates, regulations, economics, or surface land usage. The following are examples of scenarios for considering these criteria in CO_2 capacity assessments:

Injectivity

The daily or annual rate of CO_2 that can be injected into a specific geologic formation is described or inferred by the term "injectivity." Relatively low or high injectivity for a formation is determined by the flow characteristics of the formation (e.g., pressure, permeability, and thickness), the type and size of wellbore drilled, the type of completion, and the number of wells.

No injectivity (zero) means there is no injection rate under any circumstances and as such a geologic formation without injectivity cannot be considered a CO_2 resource. However, a geologic formation with low injectivity that provides a CO_2 injection rate greater than zero does provide the opportunity to store CO_2 and is considered a CO_2 resource.

For selecting and designing specific storage sites, a minimum acceptable injection rate for a well is required to meet the capture rate of CO_2 emitted by the industrial site or utility. For example, if injectivity and storage for 1 million tons per year from an industrial plant is desired for 30 years, the first step in selecting an injection site is to find a geologic unit or group of units as close to the emission site as feasible (to minimize transportation costs) that has adequate CO_2 resource of at least 30 million tons. This industrial plant would likely have a budget (or economic limits) for capturing and storing CO_2 on a per-ton basis (e.g, $15/ton). One of the next steps is to establish the most affordable means of injecting CO_2 that does not exceed the $15/ton economic limit. One single well that could inject at least 1 million tons per year might be the least-cost option. However, if one well cannot provide this high rate of injectivity, additional wells or more expensive well types and completions will be considered. If the number of wells required to meet the 1 million tons per year has expenses that exceed $15/ton, then the site will not be selected and a different storage site further from the source may be considered.

For this example, the resource exists, but under the current economic conditions for this company at this emission site, the resource is not affordable. A different industrial plant with less CO_2 volume to store may find the same geologic unit acceptable with lower injection rate requirements or a higher economic limit than $15/ton. Moreover, the same plant, some time in the future, may have different economic drivers that can afford more wells or type of wells making the same site economical. Injection rate and the geologic parameters that determine injection rate do not affect the resource estimate, and only affect the use of the geologic unit at the present time. If the storage resource evaluated against a set of economic criteria is considered uneconomic, the storage capacity of the site is zero; however, the storage resource estimate remains unchanged.

By analogy, a producing oil well can be produced to the time that not a single drop of additional oil is produced; however, long before this time, the oil rate will be low enough that the income from the sale of oil from this well is not high enough to pay for the daily expense of operating this well. At this time the well will be abandoned even though additional oil can be produced. If the price of oil increases or the operating expenses decrease, oil can continue to be produced. For either of these cases, the oil resource is the same and its availability as a resource is not changed by economic conditions.

Regulations

The use of any resource is governed by regulations; CO_2 storage will likely be similar. Some types of regulations may be similar to the oil and gas industry and underground gas storage. Examples of regulations are maximum injection pressure and rates, minimum formation water salinity, and monitoring and reporting requirements. In other industries, regulations have historically changed for technical and environmental reasons. Additionally, many regulations have exemption clauses. For example, the injection of water into an oil reservoir will have a regulated maximum pressure, but on a well-by-well, lease, or field case, a specific test can be conducted to allow injection pressure above the regulated maximum. Exemptions are added to regulations as new information or technology is available. Because of the dynamics of regulations, the use of regulations should not be imposed on the estimate of CO_2 resource.

The use of current regulations is very pertinent to a specific site assessment with projected start-up time and duration. To continue the example of the 1-million-ton-per-year emission site, part of the $15/ton economic limit included a regulated monitoring technique that was relatively expensive. If later technology found a less expensive and equally effective method to monitor, the regulatory agency could be petitioned to consider the new technology and lower the storage cost, possibly transitioning the same geologic unit from uneconomical to economical for this industrial site.

Economics
Similar to the resource assessment of other natural resources such as petroleum accumulations and coal beds, the inclusion of economic considerations is inappropriate for a CO_2 resource assessment. In addition to project economic considerations, every company storing CO_2 will have different economic criteria to impose such as rate of return, payout, and profit/investment ratio that will affect the capacity of a geologic formation. In any storage industry scenario (e.g. carbon credits), each business will be making final estimates of available CO_2 capacity based on economic criteria. At this time it is unclear if a storage industry will emerge that has companies that provide dedicated storage services, or if corporations within existing industries, such as coal-burning power plants and ethanol-generating plants, will take on CO_2 storage as one of their business units.

Regardless of how the storage industry evolves, the assessment of CO_2 resources is unaffected by the projection of a new industry, and capacity of a site will be estimated by individual companies using their own economic criteria.

Land Usage
Current or projected use of surface land is not included in the estimate of storage resource of this *Atlas* and likely would not adversely affect most of the storage currently assessed under lands used for other purposes. This is primarily because horizontal-well technology can be used to access this type of area and would be determined by specific economic conditions on a site-by-site basis.

Land usage clearly impacts capacity. An example is lack of access to some lands such as national parks and wilderness areas, or restricted access to military reservations. Another example is a large holding of unwilling landowners.

Appendix 3: Static and Dynamic Methods for Estimating CO_2 Storage - *by Scott Frailey*

Methods available for estimating subsurface volumes are widely and routinely applied in oil and gas, ground water, underground natural gas storage, and UIC disposal-related estimations. In general, these methods can be divided into two categories: static and dynamic. The static models are volumetric and compressibility; the dynamic models are decline curve analyses, material balance, and reservoir simulation.

Volumetric
The volumetric method is the basis for CO_2 resource calculations in the *Atlas*, and is described in detail in the previous three formation sections. The volumetric formula uses porosity, area, and thickness in a Monte Carlo simulation approach with various efficiency terms included to account for ranges of variations in the geologic volumetric properties and the fraction of the accessible pore volume that is most likely to be contacted by injected CO_2.

Compressibility
The compressibility approach is generally applied to fluids with nearly constant total compressibility (c_t) over some increase or decrease to pressure (p) from an initial pressure (p_o). As such, single-phase oil reservoirs and confined saline-water-filled formations are typical applications.

The injection of CO_2 into a saline formation suggests two phases, but if the formula is applied to the water phase only, it is applicable. The equation below shows the compression of the original water volume (V_{wo}) due to an increase in pressure (p) above the initial pressure (p_o). The compressed volume (ΔV_w or G_{co2}) is the volume that CO_2 can occupy as a consequence of increasing the pressure from p_o to p via the injection process.

$$G_{co2} = \Delta V_w = V_{wo}\, c_t\, (p - p_o)$$

The original water volume V_{wo} is determined by the volumetric equation using area (A), thickness (h), and porosity (ϕ). The c_t is the sum of the pore compressibility of the formation (c_p) and the in-situ water saturating the formation (c_w).

$$c_t = c_p + c_w$$

In a closed system, where water cannot be displaced from the area around the injector, the V_{wo} is calculated based on the area defined by the boundaries of the formation.

In an open system, water is displaced from around the injector and the V_{wo} term cannot be clearly defined. Theoretically, V_{wo} is infinite for an open system and the equation is not applicable.

For an estimate of the CO_2 storage capacity of a site, p could be defined as the maximum capillary pressure of the sealing rock or a maximum pressure that may cause a boundary (e.g., a fault) to leak. This pressure is not the injection pressure of a well that may initiate or propagate a fracture due to relatively high pressure injection, but is the average water pressure of the entire V_{wo}. Because the pressure could be controlled by the production of water, this example would not be used to calculate the storage resource.

Decline Curve Analyses

The basis for estimating subsurface storage volumes using active injection assumes a type of injection rate-time relationship. The most common relationship is exponential primarily because of its simplicity. Injection rate (q_{co2}) is expected to be an exponential function of time based on an initial injection rate (q_{co2i}) and a decline coefficient (D) that reflects various flow characteristics of the formation. The general form of this equation follows:

$$q_{co2} = q_{co2i}\, e^{-Dt}$$

This formula is only applicable if injection rate varies with time due to pseudo-state conditions of pressure increasing in the formation with time and injection rate decreasing. Another variation of this formula exists for constant rate injection and variable injection pressure.

The exponential decline equation is used to determine the decline coefficient (D) given an injection rate history. The projected CO_2 capacity (G_{co2}) is based on the following equation:

$$G_{co2} = (q_{co2i} - q_{co2}) / D$$

The formula is generally applicable to individual wells or entire fields as long as the exponential trend exists between injection rate and time. Because this formula is based on injection rates only, it reflects the storage volume that is likely to be attained with continued injection; therefore, this is storage capacity. Use of the storage efficiency factor (E) could be used to estimate the storage resource that might be available.

Material Balance

The compressibility formula is a special case of the material balance equation. The complete material balance equation includes the cumulative CO_2 injection and the corresponding pore pressure (p) at various times. Fluid properties that reflect CO_2 compressibility are required. This formula can be derived very similarly to the p/z plot used in gas reservoir and underground gas storage reservoirs. (An aquifer influx or efflux term can be included based on specific site applications; in this case, aquifer properties such as water and formation compressibility are required.) This formula can be written so that a straight line appears on a cumulative CO_2 injection ($G_{inj\text{-}co2}$) versus p/z where z is the z-factor of CO_2 evaluated at pressure p.

Reservoir Simulation

Numerical modeling of geologic units that include volumetric and geologic flow properties, as well as fluid properties, is the most advanced method for estimating storage. Advanced technology does not necessarily mean improved accuracy unless the representative data are available.

Reservoir simulation includes the material balance, compressibility, and volumetrics formulas on a cell-by-cell representation of the geologic unit. It is considered an advanced methodology because it is designed to include a more realistic geologic description, fluid properties, and injection/production wells. Various development scenarios can be simulated too.

Simulation can be used to make projections or to study actual field or pilot performance. If simulation is used in design only, the basic equations may give similar results for storage estimate; for use with actual field or pilot injection and pressure data, a more improved estimate for CO_2 resource can be made.

It should be noted that the reservoir simulation method is the most resource-consuming. It needs data at a scale and resolution that make it applicable at the reservoir scale but not at the formation and basin scales.

Appendix 4: Estimation of the Storage Efficiency Factor for Saline Formations - *by Scott Frailey*

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 actually contact. The CO_2 storage efficiency factor for saline formations 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. Depending on the definitions of area, thickness, and porosity, the CO_2 storage efficiency factor may also reflect the volumetric difference between bulk volume, total pore volume, and effective pore volume.

Because formation thickness and total porosity are used in the saline CO_2 resource equation, efficiency must include terms that adjust gross thickness to net thickness and total porosity to effective porosity (see definitions in table on following page).

These terms can be grouped into a single term that defines the entire basin's or region's pore volume and terms that reflect local formation effects in the injection area of a specific injection well. Assuming that CO_2 injection wells can be placed regularly throughout the basin or region to maximize storage, this group of terms is applied to the entire basin or region. Given this assumption, the resource estimate is the maximum storage available because there is no restriction on the number of wells that could be used for the entire area of the basin or region. Because formation heterogeneity terms are included, this estimate could be considered a "reasonable" maximum storage resource estimate.

The following equation was used to estimate the CO_2 storage efficiency factor (E) for saline formations:

$$E_{saline} = (A_n/A_t)\,(h_n/h_g)\,(\phi_e/\phi_{tot})\,E_A\,E_I\,E_g\,E_d$$

The following terms are included in the CO_2 storage efficiency factor:

Term	Symbol (range)	Description
Terms used to define the entire basin or region pore volume		
Net to total area	A_n/A_t (0.2–0.8)	Fraction of total basin or region area that has a suitable formation present.
Net to gross thickness	h_n/h_g (0.25–0.75)	Fraction of total geologic unit that meets minimum porosity and permeability requirements for injection.
Effective to total porosity ratio	ϕ_e/ϕ_{tot} (0.6–0.95)	Fraction of total porosity that is effective, i.e., interconnected.
Terms used to define the pore volume immediately surrounding a single well CO_2 injector		
Areal displacement efficiency	E_A (0.5–0.8)	Fraction of immediate area surrounding an injection well that can be contacted by CO_2; most likely influenced by areal geologic heterogeneity such as faults or permeability anisotropy.
Vertical displacement efficiency	E_I (0.6–0.9)	Fraction of vertical cross section (thickness), with the volume defined by the area (A) that can be contacted by the CO_2 plume from a single well; most likely influenced by variations in porosity and permeability between sublayers in the same geologic unit. If one zone has higher permeability than others, the CO_2 will fill this zone quickly and leave the other zones with less CO_2 or no CO_2 in them.
Gravity	E_g (0.2–0.6)	Fraction of net thickness that is contacted by CO_2 as a consequence of the density difference between CO_2 and in-situ water. In other words, $1-E_g$ is that portion of the net thickness **not** contacted by CO_2 because the CO_2 rises within the geologic unit.
Microscopic displacement efficiency	E_d (0.5–0.8)	Portion of the CO_2-contacted, water-filled pore volume that can be replaced by CO_2. E_d is directly related to irreducible water saturation in the presence of CO_2.

The range of values for each parameter is an approximation to reflect various lithologies and geologic depositional systems that occur throughout the Nation. The maximum and minimum are meant to be reasonable high and low values for each parameter.

The table below gives results of six Monte Carlo simulations of the distribution of values described. (The fourth and fifth cases are run to assess sensitivity to the input parameters and are not considered valid for interpretation of E.) Selection of distributions was to see the effect of choice of distribution on the final answer. The P_{50} case seems less sensitive to choice of distribution. P_{15} and P_{85} cases are more sensitive to the distribution selection and parameters that describe the distribution. No rigor was given to selection of the distribution or the parameters that describe them. The intent of these Monte Carlo simulations was to give some basis or perspective for choice of the magnitude of total storage efficiency (E). In other words, this is an example of a combination of ranges of parameters and distributions that would yield a P_{50} E of approximately 1.8 to 2.2 percent.

Case	Parameter	Range	Distribution	P_{15}	P_{50}	P_{85}	Comment
Base-uniform	A_n/A_t h_n/h_g ϕ_e/ϕ_{tot} E_A E_I E_g E_d	0.2–0.8 0.25–0.75 0.6–0.95 0.5–0.8 0.6–0.9 0.2–0.6 0.5-0.8	Uniform Uniform Uniform Uniform Uniform Uniform Uniform	1.6	2.7	4.2	
Base-normal with variance 1.0 max-min difference	A_n/A_t h_n/h_g ϕ_e/ϕ_{tot} E_A E_I E_g E_d	0.2–0.8 0.25–0.75 0.6–0.95 0.5–0.8 0.6–0.9 0.2–0.6 0.5–0.8	Normal Normal Normal Normal Normal Normal Normal	0.44	1.8	4.1	Median given as midpoint of range; variance given as max less median (broad flat normal distribution).
Base-normal with variance ½ max-min difference	A_n/A_t h_n/h_g ϕ_e/ϕ_{tot} E_A E_I E_g E_d	0.2–0.8 0.25–0.75 0.6–0.95 0.5–0.8 0.6–0.9 0.2–0.6 0.5–0.8	Normal Normal Normal Normal Normal Normal Normal	1.2	2.2	3.7	Median given as midpoint of range; variance given as one-half max less median (narrow, spike normal distribution).
Base-normal with variance 2.0 max-min difference	A_n/A_t h_n/h_g ϕ_e/ϕ_{tot} E_A E_I E_g E_d	0.2–0.8 0.25–0.75 0.6–0.95 0.5–0.8 0.6–0.9 0.2–0.6 0.5–0.8	Normal Normal Normal Normal Normal Normal Normal	0.22	1.9	10	Median given as midpoint of range; variance given as twice max less median (very broad, flat normal distribution). P85 likely too high as wide distribution makes values of some components over 1.0.
Base-normal with variance 1.0 max-min difference with minimum imposed	A_n/A_t h_n/h_g ϕ_e/ϕ_{tot} E_A E_I E_g E_d	0.2–0.8 0.25–0.75 0.6–0.95 0.5–0.8 0.6–0.9 0.2–0.6 0.5–0.8	Normal Normal Normal Normal Normal Normal Normal	1.7	3.7	8.0	Median given as midpoint of range; variance given as max less median (broad flat normal distribution); minimum equals low of range.
Base-mixed distribution	A_n/A_t h_n/h_g ϕ_e/ϕ_{tot} E_A E_I E_g E_d	0.2–0.8 0.25–0.75 0.6–0.95 0.5–0.8 0.6–0.9 0.2–0.6 0.5–0.8	Uniform Normal Uniform Normal Log Normal Normal Normal	0.65	1.9	4.4	Change in distribution based on possible petrophysical distribution.

Averaging and rounding these values results in a **low value of E of 0.01 and a high value of 0.04**; these values provide a 15 to 85 percent confidence range.

Appendix 5: Estimation of Storage Efficiency Factor for Unmineable Coal Formations - *by Scott Frailey*

Efficiency is the multiplicative combination of volumetric parameters that reflect the portion of a basin's or region's coal bulk volume that CO_2 is expected to actually contact.

The terms that describe this volume can be grouped into one term that defines the entire basin's or region's coal bulk volume and the local formation effects in the injection area of a specific injection well. Assuming that CO_2 injection wells can be placed regularly throughout the basin or region to maximize the basin's coal storage, this group of terms is applied to the entire basin or region. The capacity estimate is therefore the maximum storage available because there is no restriction in the number of wells that could be used for the entire basin or region area. Because formation heterogeneity terms are included, however, this estimate could be considered a "reasonable" maximum storage estimate.

All of the terms are the same conceptually as with saline, except that the "effective porosity to total porosity" term was dropped. It is not in the coal volumetric equation; it is replaced by "concentration" from the Langmuir isotherm. Definitions in the table at right are modified for coal. Because of the lack of extensive enhanced coalbed methane (ECBM) field experience, ranges are based loosely on coalbed methane (CBM) production and computer modeling observations.

The adsorptiveness of coal compared to storage in porous media causes the range of parameters for displacement efficiency terms to be much higher than similar terms for porous media. Although geologic heterogeneity is expected in coal, the permeability reduction expected in coal due to CO_2 swelling will most likely have a "correcting" mechanism, which reduces the velocity of CO_2 as the coal swells and redirects CO_2 to lesser-swept parts of the coal seam. Since coal is thinner than saline formations, gravity effects will likely be very slight, so this term was erased also. The bulk coal terms (A/A and h/h) are increased because most basin coals would be better defined compared with saline formations.

The following equation was used to estimate the CO_2 storage efficiency factor (E) for coal seams:

$$E_{coal} = (A_n/A_t)\ (h_n/h_g)\ E_A\ E_I\ E_g\ E_d$$

The following terms are included in the CO_2 storage efficiency factor for coal:

Term	Symbol (range)	Description
Terms used to define the entire basin or region bulk coal volume		
Net to total area	A_n/A_t (0.6–0.8)	Fraction of total basin or region area that has bulk coal present; used if known or suspected locations are within a basin or region outline where a coal seam may be discontinuous. For example, in the Illinois Basin there are subregions within the basin where sand channels have incised and replaced coal. This situation can be handled through this term.
Net to gross thickness	h_n/h_g (0.75–0.90)	Fraction of total coal seam thickness that has adsorptive capability.
Terms used to define the coal volume immediately surrounding a single well CO_2 injector		
Areal displacement efficiency	E_A (0.7–0.95)	Fraction of the immediate area surrounding an injection well that can be contacted by CO_2; most likely influenced by areal geologic heterogeneity such as faults or permeability anisotropy.
Vertical displacement efficiency	E_I (0.8–0.95)	Fraction of the vertical cross section (thickness), with the volume defined by the area (A) that can be contacted by a single well; most likely influenced by variations in the cleat system within the coal. If one zone has higher permeability than others, the CO_2 will fill it quickly and leave the other zones with less CO_2 or no CO_2 in them.
Gravity	E_g (0.9–1.0)	Fraction of the net thickness that is contacted by CO_2 as a consequence of the density difference between CO_2 and the in-situ water in the cleats. In other words, $1\text{-}E_g$ is the portion of the net thickness **not** contacted by CO_2 because the CO_2 rises within the coal seam.
Microscopic displacement efficiency	E_d (0.75–0.95)	Reflects the degree of saturation achievable for in-situ coal compared with the theoretical maximum predicted by the CO_2 Langmuir Isotherm.

The range of values for each parameter is an approximation to reflect various coals. The maximum and minimum are meant to be reasonable high and low values for each parameter.

The following table gives results of five Monte Carlo simulations of the distribution of points that are given in the previous table. The selection of distributions was to see the effect of choice of distribution on the final answer. The P_{50} case seems less sensitive to choice of distribution. P_{15} and P_{85} cases are more sensitive to distribution selection and parameters that describe the distribution. No rigor was given to the selection of the distribution or the parameters that describe them. The intent of these Monte Carlo simulations was to give some basis or perspective for the choice of magnitude of total efficiency (E). In other words, this is an example of a combination of ranges of parameters and distributions that would yield a P_{50} E of 33 percent.

Case	Parameter	Range	Distribution	P_{15}	P_{50}	P_{85}	Comment
Base-uniform	A_n/A_t h_n/h_g E_A E_I E_g E_d	0.6–0.8 0.75–0.90 0.7–0.95 0.8–0.95 0.9–1.0 0.75–0.95	Uniform Uniform Uniform Uniform Uniform Uniform	28	33	40	
Base-normal with variance 1.0 max-min difference	A_n/A_t h_n/h_g E_A E_I E_g E_d	0.6–0.8 0.75–0.90 0.7–0.95 0.8–0.95 0.9–1.0 0.75–0.95	Normal Normal Normal Normal Normal Normal	25	33	43	Median given as midpoint of range; variance given as max less median (broad flat normal distribution).
Base-normal with variance ½ max-min difference	A_n/A_t h_n/h_g E_A E_I E_g E_d	0.6–0.8 0.75–0.90 0.7–0.95 0.8–0.95 0.9–1.0 0.75–0.95	Normal Normal Normal Normal Normal Normal	29	33	38	Median given as midpoint of range; variance given as one-half max less median (narrow, spike normal distribution).
Base-normal with variance 2.0 max-min difference	A_n/A_t h_n/h_g E_A E_I E_g E_d	0.6–0.8 0.75–0.90 0.7–0.95 0.8–0.95 0.9–1.0 0.75–0.95	Normal Normal Normal Normal Normal Normal	16	29	53	Median given as midpoint of range; variance given as twice max less median (very broad, flat normal distribution) P85 likely too high as wide distribution makes values of some components over 1.0.
Base-normal with variance 1.0 max-min difference with minimum imposed	A_n/A_t h_n/h_g E_A E_I E_g E_d	0.6–0.8 0.75–0.90 0.7–0.95 0.8–0.95 0.9–1.0 0.75–0.95	Normal Normal Normal Normal Normal Normal	32	39	49	Median given as midpoint of range; variance given as max less median (broad flat normal distribution); minimum equals low of range.

Depending on how mapping was conducted, the value for E could reflect the volumetric difference between bulk volume and coal volume, or it could reflect coal-quality factors such as ash content, amount of moisture, heating value, vitrinite reflectance, maceral composition, and total organic content.

Compared with that of coalbed methane recovery, the value of storage efficiency of 33 percent is relatively low. The difference is that 50 to 75 percent storage efficiency may be more likely in a well field where coal is present in 100 percent of the area studied. When applying this efficiency to a basin, two factors (A/A and h/h) reduce this value to account for the volumes of the basin that actually have coal present with adsorptive coal capacity. If these terms are removed or if the volume of coal was known with 100 percent certainty, a storage factor of 57 percent would be predicted with this range of values. This storage factor is in agreement with coalbed methane recovery.

For the National Resource Estimate, Monte Carlo simulations estimate a **range of E of 0.28 to 0.40**; these values provide a 15 to 85 percent confidence range.

Appendix 6: Comparison of Pore Volume Occupied by CO_2 Dissolution in Saline and Free Phase CO_2 - *by Scott Frailey*

Because some RCSPs used dissolution of CO_2 in water and other RCSPs used free-phase CO_2 to estimate their respective basin's/region's storage resource, the total storage efficiency (E) derived for use in one technique is not equivalent or applicable to the other.

The dominant mechanism of CO_2 storage may change from storage of an immiscible free-phase to CO_2 dissolved in water over time, causing the proportion of dissolved CO_2 to a basin's/region's pore volume to be larger than the proportion contacted by free phase CO_2. Several RCSPs focused on dissolved storage for capacity calculation. To avoid requiring any RCSPs to repeat a rigorous calculation of capacity with new methodology, a method of converting E for free-phase CO_2 to the equivalent E for dissolved CO_2 is desirable. The example below shows how it can be done.

Example calculation for a formation at 8,000 feet, with temperature of 140 °F and 3,500 pounds per square inch absolute (psia) saturated with 100,000 parts per million (ppm) water. The density of CO_2 is 48.55 pound mass per cubic foot (lbm/ft^3), and dissolution in this saline is 118 standard cubic feet/stock tank barrel (scf/stb). (MIDCARB, 2004, Midcontinent Interactive Digital Carbon Atlas and Relational database [MIDCARB], http://www.midcarb.org/calculators.shtml accessed February 14, 2007; Practical Aspects of CO_2 Flooding, 2002, Perry M. Jarrell, Charles E. Fox, Michael H. Stein and Steve L. Webb Society of Petroleum Engineers [SPE] Monograph 22, 220p.)

Using a common basis of 1 ft^3 of pore volume, the 48.55 lbm of free-phase CO_2 occupies 1 ft^3 of pore space.

For dissolution of CO_2 into water, 1 ft^3 of pore space is occupied by water; 118 scf of CO_2 100% saturates a stb of 100,000 ppm water at 140 °F and 3500 psia. Converting to lbm/ft^3

$$\left(\frac{118\,\text{scf} - CO_2}{\text{stb} - \text{water}}\right)\left(\frac{1\,\text{bbl}}{5.615\,\text{ft}^3}\right)\left(\frac{1\,\text{ton} - CO_2}{17{,}140\,\text{scf} - CO_2}\right)\left(\frac{2000\,\text{lbm}}{\text{ton}}\right) = \frac{2.452\,\text{lbm} - CO_2}{\text{ft}^3 - \text{pore volume}}$$

There is a slight difference, usually less than 1%, between a stock tank barrel of water and a formation barrel of water; for this example it was assumed that they were equal. Any increase or decrease in the 1 ft^3 of water volume due to dissolution of CO_2 was not included in this example.

The ratio of 48.55 to 2.452 is used to convert from the E derived for free phase to the E for dissolution, which is 19.8 in this example. If the E for free-phase CO_2 is 2%, the equivalent E for dissolution is 2 × 19.8, or 39.6%. Interestingly if the E-free phase was 5%, the equivalent E-dissolution for this example, is 99%. So at the assumed salinity, if 5% of a basin's pore volume is free-phase CO_2, the equivalent mass distributed via dissolution in water would require 99% of the basin's pore volume.

Because of variation of pressure, temperature, and salinity as a function of depth across a basin or region, an average value should be used to calculate the conversion factor from free phase to dissolution for the entire region; otherwise a rigorous GIS study would be required to make the conversion at different values of pressure, salinity, and temperature.

Stationary Source and Geologic Storage Estimates for Carbon Dioxide by State/Province

APPENDIX C

Prepared for

U.S. Department of Energy
National Energy Technology Laboratory
Carbon Sequestration Program

Prepared by

DOE Regional Carbon Sequestration Partnerships and the National Carbon Sequestration Database and Geographical Information System

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Stationary Source Emissions Estimates by State/Province for CO_2

The Table ("Identified Stationary CO_2 Sources") displays stationary source data by state/province which were obtained from the RCSPs and compiled by NATCARB. As described on page 17, a total of more than 4,600 stationary sources with total annual emissions exceeding 3,200 million metric tons (3,500 million tons) of CO_2 have been documented by the RCSPs.

Information on the methods used in estimating stationary source emissions can be found in the "CO_2 Stationary Source Emission Estimation Methodologies Summary" in Appendix A. Emissions data specific to each RCSP can be found within each RCSP's section of this document.

States with the greatest stationary source emissions include Texas, Indiana, Florida, Ohio, Pennsylvania, Illinois, New York, Kentucky, California, and West Virginia. The 332 stationary sources identified in Texas are estimated to emit 365 million metric tons/year (402 million tons/year) of CO_2. The 82 stationary sources identified in Indiana are estimated to emit 164 million metric tons/year (181 million tons/year). The 108 stationary sources identified in Florida are estimated to emit 143 million metric tons/year (157 million tons/year).

Identified Stationary CO_2 Sources

State/Province	CO_2 Emissions Million Metric Ton/Year	Number of Sources
Alabama	79.6	59
Alaska	6.0	20
Alberta	95.5	101
Arizona	59.5	24
Arkansas	34.5	30
British Columbia	3.4	6
California	103.7	159
Colorado	46.7	56
Connecticut	9.7	63
Delaware	6.2	16
District of Columbia	0.2	5
Florida	142.7	108
Georgia	89.9	64
Hawaii	8.3	40
Idaho	2.5	16
Illinois	121.1	150
Indiana	164.1	82
Iowa	50.3	178
Kansas	43.9	102
Kentucky	106.8	50
Louisiana	98.7	129
Maine	5.3	106
Manitoba	1.7	9
Maryland	38.1	22
Massachusetts	24.6	137
Michigan	95.7	54
Minnesota	65.6	168
Mississippi	33.8	48
Missouri	89.8	217
Montana	45.5	71
Nebraska	30.6	94
Nevada	26.9	19
New Hampshire	8.3	66
New Jersey	15.4	103
New Mexico	31.7	32
New York	111.4	412
North Carolina	76.8	55
North Dakota	41.6	58
Ohio	139.1	53
Oklahoma	51.6	45
Ontario	3.3	2
Oregon	12.6	14
Pennsylvania	131.0	74
Rhode Island	2.2	18
Saskatchewan	19.0	18
South Carolina	40.3	48
South Dakota	18.0	38
Tennessee	65.6	29
Texas	364.8	332
Utah	39.1	27
Vermont	0.4	73
Virginia	46.4	56
Washington	25.4	21
West Virginia	102.1	30
Wisconsin	81.6	580
Wyoming	53.7	87
TOTAL	3,212	4,674

Total CO_2 Storage Resource Estimates by State/Province

The Table ("Total CO_2 Storage Resource") displays the total CO_2 resource estimates by state/province which were obtained from the RCSPs and compiled by NATCARB. The total CO_2 resource is the sum of oil and gas reservoir, unmineable coal seam, and deep saline formation CO_2 resource estimates. The current total CO_2 storage resource identified by the RCSPs is approximately 3,600 to 12,900 billion metric tons (3,900 to 14,200 billion tons).

Information on the methods used in estimating CO_2 storage resource can be found in the "Methodology for Development of Geologic Storage Estimates for Carbon Dioxide" in Appendix B. It is important to note that the data in the table is a high-level overview and is not intended as a substitute for site-specific assessment and testing. Individual projects will require development of detailed geologic models and simulation of CO_2 injection to estimate site-specific storage potential.

*Total CO_2 Storage Resource**

State/Province	Million Metric Tons		Million Tons	
	Low Estimate	High Estimate	Low Estimate	High Estimate
Alabama	31,260	117,765	34,458	129,813
Alaska	84,000	84,000	92,594	92,594
Alberta	87,625	87,625	96,590	96,590
Arizona	254	810	280	893
Arkansas	11,929	41,778	13,150	46,052
British Columbia	749	749	826	826
California	83,567	311,194	92,117	343,032
Colorado	36,312	125,781	40,028	138,650
Connecticut	11	46	13	51
Delaware	1	5	1	5
District of Columbia	14	57	16	63
Florida	43,828	170,078	48,313	187,479
Georgia	3,313	13,252	3,652	14,608
Hawaii	0	0	0	0
Idaho	0	0	0	0
Illinois	20,693	78,226	22,810	86,229
Indiana	13,440	53,313	14,815	58,768
Iowa	3	10	3	11
Kansas	4,326	12,232	4,769	13,484
Kentucky	7,175	27,583	7,909	30,405
Louisiana	420,944	1,633,040	464,011	1,800,116
Maine	0	0	0	0
Manitoba	618	618	681	681
Maryland	1,315	5,266	1,450	5,804
Massachusetts	6	25	7	27
Michigan	20,651	81,487	22,764	89,824
Minnesota	0	0	0	0
Mississippi	118,744	454,150	130,893	500,614
Missouri	152	606	167	669

State/Province	Million Metric Tons		Million Tons	
	Low Estimate	High Estimate	Low Estimate	High Estimate
Montana	266,962	990,386	294,275	1,091,712
Nebraska	13,434	13,524	14,808	14,908
Nevada	0	0	0	0
New Hampshire	0	0	0	0
New Jersey	49	198	54	218
New Mexico	40,510	137,301	44,654	151,348
New York	2,969	10,869	3,273	11,981
North Carolina	3,679	14,714	4,055	16,220
North Dakota	30,478	35,498	33,597	39,130
Ohio	10,790	32,336	11,894	35,644
Oklahoma	11,165	14,033	12,307	15,469
Ontario	1	3	1	3
Oregon	16,727	66,909	18,438	73,754
Pennsylvania	8,247	24,263	9,091	26,746
Rhode Island	0	0	0	0
Saskatchewan	29,666	29,666	32,701	32,701
South Carolina	1,373	5,491	1,513	6,053
South Dakota	28,210	65,219	31,096	71,892
Tennessee	1,249	4,998	1,376	5,509
Texas	599,899	2,207,530	661,275	2,433,382
Utah	34,005	130,519	37,484	143,873
Vermont	0	0	0	0
Virginia	496	1,161	547	1,280
Washington	93,045	363,779	102,564	400,997
West Virginia	4,873	14,994	5,372	16,528
Wisconsin	0	0	0	0
Wyoming	217,820	784,329	240,105	864,574
Offshore	1,184,928	4,686,453	1,306,158	5,165,924
TOTAL	3,591,506	12,933,868	3,958,953	14,257,132

* States/Provinces with a "zero" value represent estimates of minimal CO_2 storage resource.

CO_2 Storage Resource Estimates for Oil and Gas Reservoirs by State/Province

The Table ("CO_2 Storage Resource Estimates for Oil and Gas Reservoirs") displays oil and gas reservoir CO_2 resource estimates by state/province. As described on page 18, the RCSPs have documented the location of 138 billion metric tons (152 billion tons) of CO_2 storage potential in oil and gas reservoirs distributed over 27 states and 3 provinces. In the Table, states/provinces with a "zero" value represent estimates of minimal oil and gas reservoir CO_2 storage resource while states/provinces with a blank represent areas that have not yet been assessed by the RCSPs. Carbon dioxide storage resource data for oil and gas reservoirs specific to each RCSP can be found within each RCSP's section of this document. Additional details can be obtained from the NATCARB website (http://www.natcarb.org/).

Areas with the greatest oil and gas reservoir storage potential identified include Texas, offshore, Oklahoma, Alberta, New Mexico, California, and Louisiana. These CO_2 storage resources are significant, with an estimated 130 years of storage available in Texas oil and gas reservoirs at Texas's current emission rate. Oklahoma's oil and gas reservoirs are estimated to have CO_2 resource for 194 years worth of emissions from the state.

It is important to note that the data in the table is a high-level overview and is not intended as a substitute for site-specific assessment and testing. Individual projects will require development of detailed geologic models and simulation of CO_2 injection to estimate site-specific storage potential.

*CO_2 Storage Resource Estimates for Oil & Gas Reservoirs by State**

State/Province	Million Metric Tons	Million Tons
Alabama	427	471
Alaska		
Alberta	9,328	10,282
Arizona	70	77
Arkansas	313	345
British Columbia		
California	7,692	8,479
Colorado	1,723	1,899
Connecticut	0	0
Delaware	0	0
District of Columbia	0	0
Florida	197	217
Georgia	0	0
Hawaii	0	0
Idaho	0	0
Illinois	338	373
Indiana	68	75
Iowa	0	0
Kansas	1,624	1,791
Kentucky	104	114
Louisiana	6,990	7,705
Maine	0	0
Manitoba	618	681
Maryland	0	0
Massachusetts	0	0
Michigan	457	504
Minnesota	0	0
Mississippi	699	771
Missouri		

State/Province	Million Metric Tons	Million Tons
Montana	1,262	1,391
Nebraska	23	26
Nevada		
New Hampshire	0	0
New Jersey	0	0
New Mexico	8,246	9,090
New York	240	264
North Carolina		
North Dakota	4,589	5,059
Ohio	3,481	3,838
Oklahoma	10,012	11,036
Ontario		
Oregon		
Pennsylvania	2,759	3,041
Rhode Island	0	0
Saskatchewan	6,245	6,884
South Carolina	0	0
South Dakota	232	255
Tennessee		
Texas	47,761	52,648
Utah	1,410	1,544
Vermont	0	0
Virginia	81	89
Washington	0	0
West Virginia	1,353	1,492
Wisconsin	0	0
Wyoming	2,100	2,315
Offshore	17,628	19,432
TOTAL	138,070	152,198

* States/Provinces with a "zero" value represent estimates of minimal oil and gas reservoir CO_2 storage resource while states/provinces with a blank represent areas that have not yet be assessed by the RCSPs.

CO_2 Storage Resource Estimates for Unmineable Coal Seams by State/Province

The Table ("CO_2 Storage Resource Estimates for Unmineable Coal Seams") displays unmineable coal seam storage resource estimates by state/province. As described on page 19, the RCSPs have documented the location of 157 to 178 billion metric tons (173 to 196 billion tons) of CO_2 geologic storage potential in unmineable coal seams distributed over 24 states and 3 provinces. In the Table, states/provinces with a zero represent estimates of minimal unmineable coal seam CO_2 storage resource while states/provinces with a blank represent areas that have not yet be assessed by the RCSPs. Unmineable coal seam CO_2 storage resource data specific to each RCSP can be found within each RCSP's section of this document. Additional details can be obtained from the NATCARB website (http://www.natcarb.org/).

Areas with the greatest unmineable coal seam CO_2 storage resource identified include Alaska, Wyoming, Texas, Louisiana, Mississippi, Alberta, Washington, Alabama, and Arkansas. These CO_2 storage resources are significant, with an estimated 14,000 years of CO_2 storage resource available in Alaska unmineable coal seams for Alaska's current emission rate. Wyoming's unmineable coal seams alone are estimated to have storage resource for 350 to 356 years worth of emissions from the state.

It is important to note that the data in the table is a high-level overview and is not intended as a substitute for site-specific assessment and testing. Individual projects will require development of detailed geologic models and simulation of CO_2 injection to estimate site-specific storage potential.

CO_2 Storage Resource Estimates for Unmineable Coal Seams*

State/Province	Million Metric Tons		Million Tons	
	Low Estimate	High Estimate	Low Estimate	High Estimate
Alabama	2,333	3,308	2,572	3,646
Alaska	84,000	84,000	92,594	92,594
Alberta	3,197	3,197	3,524	3,524
Arizona	0	0	0	0
Arkansas	2,000	3,001	2,205	3,308
British Columbia				
California				
Colorado	489	858	540	946
Connecticut	0	0	0	0
Delaware	0	0	0	0
District of Columbia	0	0	0	0
Florida	1,795	2,534	1,978	2,793
Georgia	0	0	0	0
Hawaii				
Idaho	0	0	0	0
Illinois	1,371	1,953	1,511	2,153
Indiana	172	245	190	271
Iowa	3	10	3	11
Kansas	2	8	2	9
Kentucky	276	385	304	424
Louisiana	11,554	16,448	12,736	18,131
Maine	0	0	0	0
Manitoba	0	0	0	0
Maryland	5	5	6	6
Massachusetts				
Michigan				
Minnesota	0	0	0	0
Mississippi	7,289	10,424	8,034	11,491
Missouri	3	12	3	13
Montana	293	293	322	322
Nebraska	0	1	0	1
Nevada	0	0	0	0
New Hampshire	0	0	0	0
New Jersey	0	0	0	0
New Mexico	78	310	86	342
New York	129	129	142	142
North Carolina				
North Dakota	599	599	660	660
Ohio	192	192	212	212
Oklahoma	4	10	4	11
Ontario	0	0	0	0
Oregon				
Pennsylvania	198	198	219	219
Rhode Island	0	0	0	0
Saskatchewan				
South Carolina	0	0	0	0
South Dakota				
Tennessee	1	1	1	1
Texas	18,538	26,469	20,435	29,177
Utah	30	120	33	132
Vermont	0	0	0	0
Virginia	279	730	307	805
Washington	2,800	2,800	3,086	3,086
West Virginia	177	177	195	195
Wisconsin	0	0	0	0
Wyoming	18,788	19,109	20,710	21,064
Offshore	0	0	0	0
TOTAL	156,595	177,526	172,616	195,689

* States/Provinces with a "zero" value represent estimates of minimal unmineable coal seam CO_2 storage resource while states/provinces with a blank represent areas that have not yet be assessed by the RCSPs.

Deep Saline Formation Storage Resource Estimates by State/Province

The table displays deep saline formation storage resource estimates by state/province. As described on page 20, the RCSPs have documented the location of deep saline formations with an estimated storage potential from 3,300 to more than 12,200 billion metric tons (from 3,600 to more than 13,500 billion tons). In the table, states/provinces with a zero represent estimates of deep saline formation storage resource while states/provinces with a blank represent areas that have not yet be assessed by the RCSPs. Deep saline formation storage resource data specific to each RCSP can be found within each RCSP's section of this document. Additional details can be obtained from the NATCARB website (http://www.natcarb.org/).

Areas with the greatest deep saline formation storage resource identified include offshore, Texas, Louisiana, Montana, Wyoming, Mississippi, Washington, California, Alberta, and Florida. These storage resources are significant, with an estimated 1,466 to 5,860 years of storage resource available in Texas deep saline formations for Texas's current emission rate.

It is important to note that the data in the table is a high-level overview and is not intended as a substitute for site-specific assessment and testing. Individual projects will require development of detailed geologic models and simulation of CO_2 injection to estimate site-specific storage potential.

CO_2 Storage Resource Estimates for Deep Saline Formations*

State/ Province	Million Metric Tons		Million Tons	
	Low Estimate	High Estimate	Low Estimate	High Estimate
Alabama	28,500	114,030	31,416	125,696
Alaska				
Alberta	75,100	75,100	82,783	82,783
Arizona	184	740	203	816
Arkansas	9,616	38,465	10,600	42,400
British Columbia	749	749	826	826
California	75,875	303,502	83,638	334,553
Colorado	34,100	123,200	37,589	135,805
Connecticut	11	46	13	51
Delaware	1	5	1	5
District of Columbia	14	57	16	63
Florida	41,837	167,348	46,118	184,469
Georgia	3,313	13,252	3,652	14,608
Hawaii				
Idaho				
Illinois	18,984	75.935	20,926	83,704
Indiana	13,200	53.000	14,550	58,422
Iowa				
Kansas	2,700	10,600	2,976	11,684
Kentucky	6,796	27,094	7,491	29,866
Louisiana	402,401	1,609,602	443,570	1,774,280
Maine				
Manitoba				
Maryland	1,309	5,260	1,443	5,798
Massachusetts	6	25	7	27
Michigan	20,194	81,030	22,260	89,320
Minnesota				
Mississippi	110,757	443,026	122,088	488,352
Missouri	149	595	164	655
Montana	265,407	988,831	292,561	1,089,998
Nebraska	13,410	13,500	14,782	14,881
Nevada				
New Hampshire				
New Jersey	49	198	54	218
New Mexico	32,186	128,744	35,479	141,916
New York	2,600	10,500	2,866	11,574
North Carolina	3,679	14,714	4,055	16,220
North Dakota	25,290	30,310	27,877	33,411
Ohio	7,117	28,663	7,845	31,595
Oklahoma	1,149	4,011	1,267	4,421
Ontario	1	3	1	3
Oregon	16,727	66,909	18,438	73,754
Pennsylvania	5,290	21,306	5,831	23,486
Rhode Island				
Saskatchewan	23,420	23,420	25,817	25,817
South Carolina	1,373	5,491	1,513	6,053
South Dakota	27,979	64,987	30,841	71,636
Tennessee	1,248	4,997	1,376	5,508
Texas	533,600	2,133,300	588,193	2,351,558
Utah	32,565	128,990	35,897	142,187
Vermont				
Virginia	137	350	151	386
Washington	90,245	360,979	99,478	397,911
West Virginia	3,343	13,463	3,685	14,840
Wisconsin				
Wyoming	196,932	763,120	217,080	841,195
Offshore	1,167,300	4,668,825	1,286,726	5,146,493
TOTAL	3,296,843	12,618,271	3,634,143	13,909,246

* States/Provinces with a "zero" value represent estimates of minimal deep saline formation CO_2 storage resource while states/provinces with a blank represent areas that have not yet be assessed by the RCSPs.

CO_2 Stationary Source Emissions and CO_2 Storage Resource Estimates Summary by State/Province

This table is a compilation of all data provided in this Appendix. State/Provinces with the "zero" represents estimates of the minimal CO_2 storage resource while States/Provinces with a blank represent areas that have not yet been accessed by the RCSPs.

CO_2 Emissions			Oil and Gas Reservoir Storage Resource	Unmineable Coal Seams Storage Resource		Deep Saline Formation Storage Resource		Total Storage Resource	
				Million Metric Tons		Million Metric Tons		Million Metric Tons	
State/ Province	Million Metric Ton/ Year	No. Sources	Million Metric Tons	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
Alabama	79.6	59	427	2,333	3,308	28,500	114,030	31,260	117,765
Alaska	6.0	20		84,000	84,000			84,000	84,000
Alberta	95.5	101	9,328	3,197	3,197	75,100	75,100	87,625	87,625
Arizona	59.5	24	70	0	0	184	740	254	810
Arkansas	34.5	30	313	2,000	3,001	9,616	38,465	11,929	41,778
British Columbia	3.4	6				749	749	749	749
California	103.7	159	7,692			75,875	303,502	83,567	311,194
Colorado	46.7	56	1,723	489	858	34,100	123,200	36,312	125,781
Connecticut	9.7	63	0	0	0	11	46	11	46
Delaware	6.2	16	0	0	0	1	5	1	5
District of Columbia	0.2	5	0	0	0	14	57	14	57
Florida	142.7	108	197	1,795	2,534	41,837	167,348	43,828	170,078
Georgia	89.9	64	0	0	0	3,313	13,252	3,313	13,252
Hawaii	8.3	40	0					0	0
Idaho	2.5	16	0	0	0			0	0
Illinois	121.1	150	338	1,371	1,953	18,984	75.935	20,693	78,226
Indiana	164.1	82	68	172	245	13,200	53	13,440	53,313
Iowa	50.3	178	0	3	10			3	10
Kansas	43.9	102	1,624	2	8	2,700	10,600	4,326	12,232
Kentucky	106.8	50	104	276	385	6,796	27,094	7,175	27,583
Louisiana	98.7	129	6,990	11,554	16,448	402,401	1,609,602	420,944	1,633,040
Maine	5.3	106	0	0	0			0	0
Manitoba	1.7	9	618	0	0			618	618
Maryland	38.1	22	0	5	5	1,309	5,260	1,315	5,266
Massachusetts	24.6	137	0			6	25	6	25
Michigan	95.7	54	457			20,194	81,030	20,651	81,487
Minnesota	65.6	168	0	0	0			0	0
Mississippi	33.8	48	699	7,289	10,424	110,757	443,026	118,744	454,150
Missouri	89.8	217		3	12	149	595	152	606
Montana	45.5	71	1,262	293	293	265,407	988,831	266,962	990,386
Nebraska	30.6	94	23	0	1	13,410	13,500	13,434	13,524
Nevada	26.9	19		0	0			0	0
New Hampshire	8.3	66	0	0	0			0	0
New Jersey	15.4	103	0	0	0	49	198	49	198
New Mexico	31.7	32	8,246	78	310	32,186	128,744	40,510	137,301
New York	111.4	412	240	129	129	2,600	10,500	2,969	10,869
North Carolina	76.8	55				3,679	14,714	3,679	14,714
North Dakota	41.6	58	4,589	599	599	25,290	30,310	30,478	35,498
Ohio	139.1	53	3,481	192	192	7,117	28,663	10,790	32,336
Oklahoma	51.6	45	10,012	4	10	1,149	4,011	11,165	14,033
Ontario	3.3	2		0	0	1	3	1	3
Oregon	12.6	14				16,727	66,909	16,727	66,909
Pennsylvania	131.0	74	2,759	198	198	5,290	21,306	8,247	24,263
Rhode Island	2.2	18	0	0	0			0	0
Saskatchewan	19.0	18	6,245			23,420	23,420	29,666	29,666
South Carolina	40.3	48	0	0	0	1,373	5,491	1,373	5,491
South Dakota	18.0	38	232			27,979	64,987	28,210	65,219
Tennessee	65.6	29		1	1	1,248	4,997	1,249	4,998
Texas	364.8	332	47,761	18,538	26,469	533,600	2,133,300	599,899	2,207,530
Utah	39.1	27	1,410	30	120	32,565	128,990	34,005	130,519
Vermont	0.4	73	0	0	0			0	0
Virginia	46.4	56	81	279	730	137	350	496	1,161
Washington	25.4	21	0	2,800	2,800	90,245	360,979	93,045	363,779
West Virginia	102.1	30	1,353	177	177	3,343	13,463	4,873	14,994
Wisconsin	81.6	580	0	0	0			0	0
Wyoming	53.7	87	2,100	18,788	19,109	196,932	763,120	217,820	784,329
Offshore	Not Applicable	Not Applicable	17,628	0	0	1,167,300	4,668,825	1,184,928	4,686,453
TOTAL	3,212	4,674	138,070	156,595	177,526	3,296,843	12,618,271	3,591,506	12,933,868

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