

# Carbon Sequestration

# A T L A S

# of the United States and Canada



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## Foreword

The Department of Energy's (DOE's) National Energy Technology Laboratory (NETL) is proud to release the first *Carbon Sequestration Atlas of the United States and Canada*. Production of this Atlas is the result of cooperation and coordination among carbon sequestration experts from local, state, and government agencies, as well as industry and academia. This Atlas presents the first coordinated assessment of carbon capture and storage (CCS) potential across the majority of the U.S. and portions of western Canada. The Atlas also provides an introduction to the carbon storage (sequestration) process, summarizes the DOE's Carbon Sequestration Program, and gives information about the CCS contributions from each Regional Carbon Sequestration Partnership (RCSP) to date.

One of the key questions concerning CCS is: how much potential is there 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 address climate change while meeting the energy demands of an ever increasing global population. The Atlas includes the most current and best available estimates of potential carbon dioxide (CO<sub>2</sub>) sequestration capacities determined by a methodology applied consistently across all of the RCSPs. All data were collected before December 2006. In the course of developing these CO<sub>2</sub> sequestration capacity estimates, it became clear that some areas had yielded more and better quality data than others. Therefore, it is acknowledged that these data sets are not comprehensive; it is, however, anticipated that CO<sub>2</sub> sequestration capacity estimates as well as geologic formation maps will be updated annually as new data are acquired and methodologies for CO<sub>2</sub> sequestration capacity 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<sub>2</sub> sequestration capacity estimates.

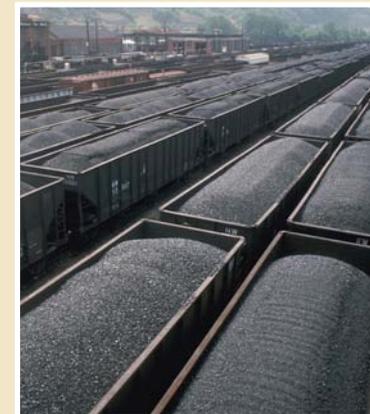
## About this Atlas

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 all CO<sub>2</sub> sources in the U.S. and portions of Canada, as well as the areal extent and capacity of geologic CO<sub>2</sub> sequestration sites evaluated within the RCSP Regions. The National Perspectives section also contains a summary of the methodologies and assumptions employed to calculate the estimated CO<sub>2</sub> sequestration capacities of various geologic formations. (Appendix A contains the complete "Methodology for Development of Carbon Sequestration Capacity Estimates" document.) The Regional Perspectives section includes a detailed presentation of CO<sub>2</sub> sequestration capacity assessments for each RCSP based on these methodologies and assumptions.

DOE thanks the many people who contributed to this Atlas.

# Contents

<b>2</b>	<b>Introduction</b>	
	– The Greenhouse Gas Effect. . . . .	2
	– A Technology Approach to Reduce GHG Emissions . . . . .	3
	– What is Carbon Sequestration?. . . . .	4
	– DOE’s Carbon Sequestration Program . . . . .	5
	– Regional Carbon Sequestration Partnerships . . . . .	6
	– National Carbon Sequestration Database and Geographical Information System . . . . .	8
<b>10</b>	<b>National Perspectives</b>	
	– Carbon Dioxide Sources . . . . .	10
	– Capacity Calculations for National Estimates . . . . .	12
	– Oil and Gas Reservoirs . . . . .	13
	– Unmineable Coal Seams. . . . .	14
	– Deep Saline Formations. . . . .	15
	– Future Geologic Sequestration Options . . . . .	16
	– Terrestrial Sequestration . . . . .	17
<b>18</b>	<b>Regional Carbon Sequestration Partnership Perspectives</b>	
	– Big Sky Carbon Sequestration Partnership . . . . .	19
	– Midwest Geological Sequestration Consortium . . . . .	26
	– Midwest Regional Carbon Sequestration Partnership . . . . .	34
	– The Plains CO <sub>2</sub> Reduction Partnership . . . . .	42
	– Southeast Regional Carbon Sequestration Partnership . . . . .	49
	– Southwest Regional Partnership on Carbon Sequestration . . . . .	56
	– West Coast Regional Carbon Sequestration Partnership . . . . .	63
<b>71</b>	<b>Appendix A: Methodology for Development of Carbon Sequestration Capacity Estimates</b>	





## 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 by various GHGs. One GHG of particular interest is carbon dioxide ( $\text{CO}_2$ ) because it accounts for over 80 percent of total United States GHG emissions.  $\text{CO}_2$  is a colorless, odorless, nonflammable gas. Atmospheric  $\text{CO}_2$  originates from both natural and man-made sources. There are multiple natural sources including volcanic out-gassing, the combustion of organic matter, and the respiration processes of living aerobic organisms: man-made, or anthropogenic, sources of  $\text{CO}_2$  are primarily the burning of various fossil fuels for power generation and transportation.

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. Emissions of  $\text{CO}_2$  from human activity have increased from an insignificant level two centuries ago to over 30 billion metric tons (33 billion tons) worldwide today. This increase of GHGs is considered by many scientists to contribute to the phenomenon of global warming and could cause unwelcome shifts in regional climates.

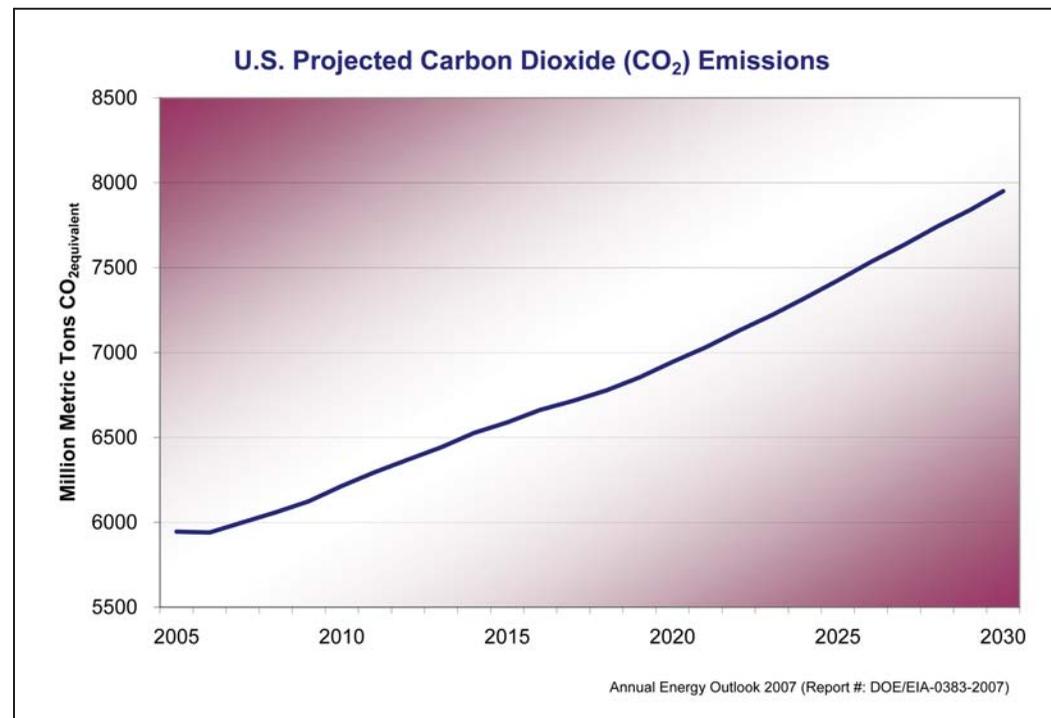
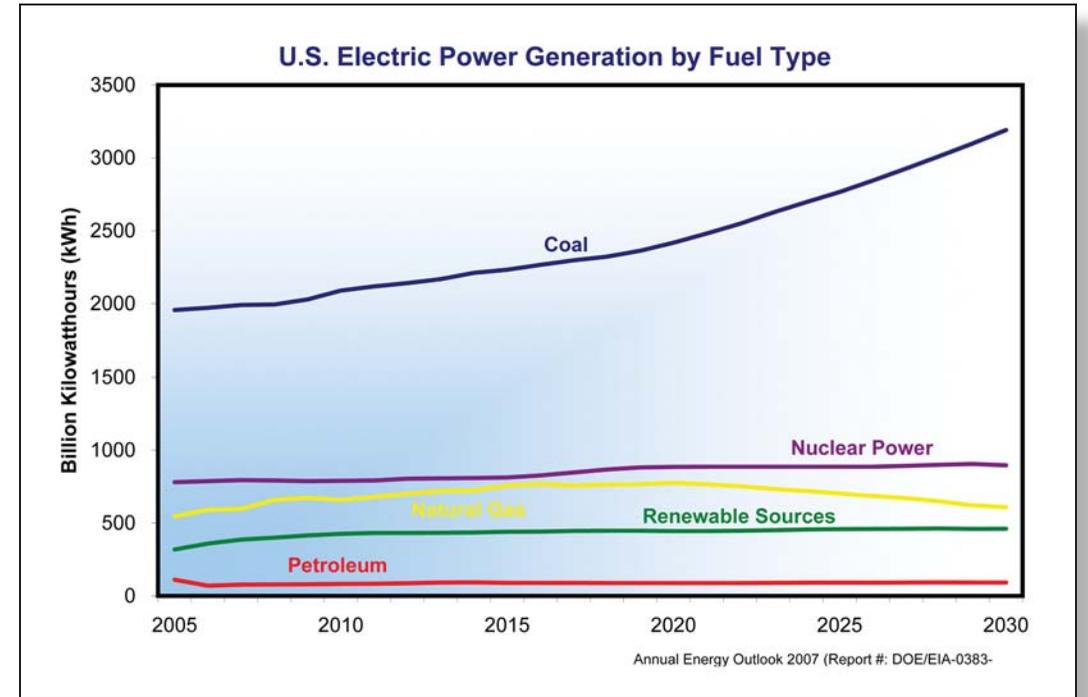
The U.S. is one of 189 countries which are signatories to the United Nations Framework Convention on Climate Change (UNFCCC), a treaty which calls for stabilization of atmospheric GHGs at a level that would prevent anthropogenic interference with the world's climate. Conservation, renewable energy, and improvements in the efficiency of power plants, automobiles, and other energy consumption devices are important first steps in any GHG emissions mitigation effort. But those approaches cannot deliver the level of emissions reduction needed to stabilize the concentrations of GHGs in the atmosphere—especially against a growing global demand for energy. Technological approaches are needed that are effective in reducing atmospheric GHG concentrations yet, at the same time, have little or no negative impacts on energy use and economic growth and prosperity. Carbon capture and storage (CCS) efforts hold great promise as such GHG reduction technologies.

## A Technology Approach to Reduce GHG Emissions

The U.S. Department of Energy’s (DOE’s) 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 controlling global climate change. The Program supports the UNFCCC efforts 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* 2007 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<sub>2</sub> emissions, making efforts to reduce these emissions a critical research need.

The Energy Information Administration’s graph “U.S. Projected Carbon Dioxide (CO<sub>2</sub>) Emissions”, shown at bottom right, illustrates the projected increase in CO<sub>2</sub> emissions over the next 25 years. Assuming no action is taken to reduce these emissions, the U.S. will emit approximately 8,000 million metric tons (8,800 million tons) of CO<sub>2</sub> by 2030, increasing 2005 emission levels by more than 33 percent. The U.S. can work toward reducing GHG emissions with the development and implementation of appropriate CCS technologies.



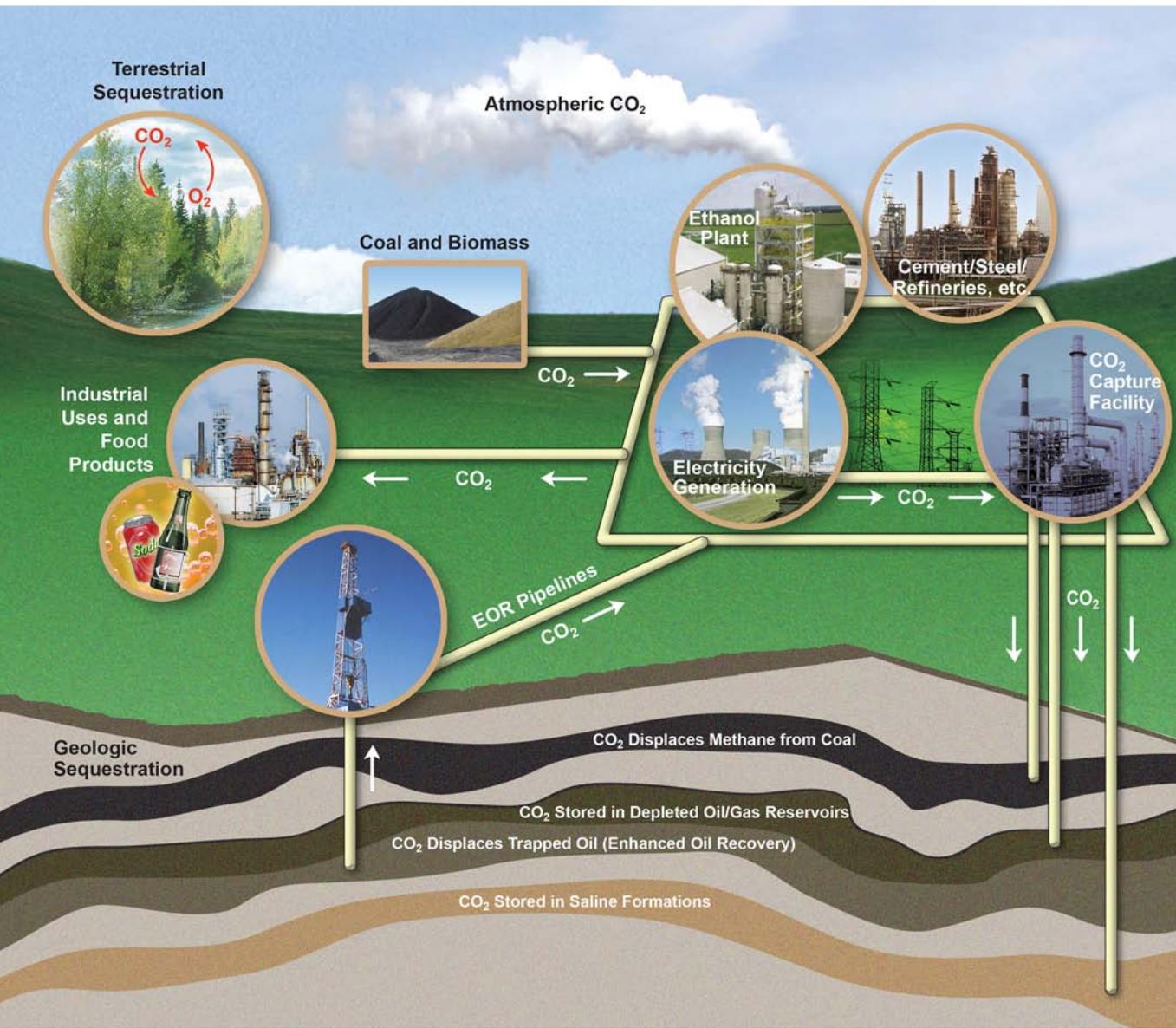
## What is Carbon Sequestration?

Carbon sequestration encompasses the processes of capture and storage of CO<sub>2</sub> that would otherwise reside in the atmosphere for long periods of time. DOE is investigating a variety of carbon sequestration options. Geologic sequestration involves the separation and capture of CO<sub>2</sub> at the point of emissions followed by storage in deep underground geologic formations. Terrestrial sequestration involves the net removal of CO<sub>2</sub> from the atmosphere by plants and microorganisms and its storage in vegetative biomass and in soils. There is significant opportunity to use terrestrial sequestration both to reduce CO<sub>2</sub> and to obtain the ancillary benefits such as habitat and water quality improvements that often result from such projects. The DOE is focusing its efforts for terrestrial sequestration on increasing carbon uptake through reforestation and amendment of minelands and other damaged soils. In addition, regional efforts are examining terrestrial sequestration through various land management techniques including no-till farming and wetland restoration.

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 for being appropriately retrofitted, will create ample opportunities for deploying efficient and cost effective CO<sub>2</sub> capture technologies. DOE's CO<sub>2</sub> capture efforts seek to cost effectively capture and purify CO<sub>2</sub> using post-combustion, pre-combustion, or oxy-combustion technologies for carbon capture.

Geologic sequestration is defined as the placement of CO<sub>2</sub> into an underground repository in such a way that it will remain permanently stored. DOE is investigating five types of underground formations for geologic sequestration, each with different challenges and opportunities for CO<sub>2</sub> sequestration: (1) mature 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 CO<sub>2</sub> sequestration includes monitoring, mitigation, and verification (MM&V) as well as risk assessment at the sequestration site. DOE's MM&V efforts focus on development and deployment of technologies that can provide an accurate accounting of stored CO<sub>2</sub> and a high level of confidence that the CO<sub>2</sub> will remain permanently sequestered. Effective application of these MM&V technologies will ensure the safety of sequestration projects with respect to both human health and the environment, and provide the basis for establishing carbon credit trading markets for sequestered CO<sub>2</sub>. Risk assessment research focuses on identifying and quantifying potential risks to humans and the environment associated with CO<sub>2</sub> sequestration and helping to ensure that these risks remain low.

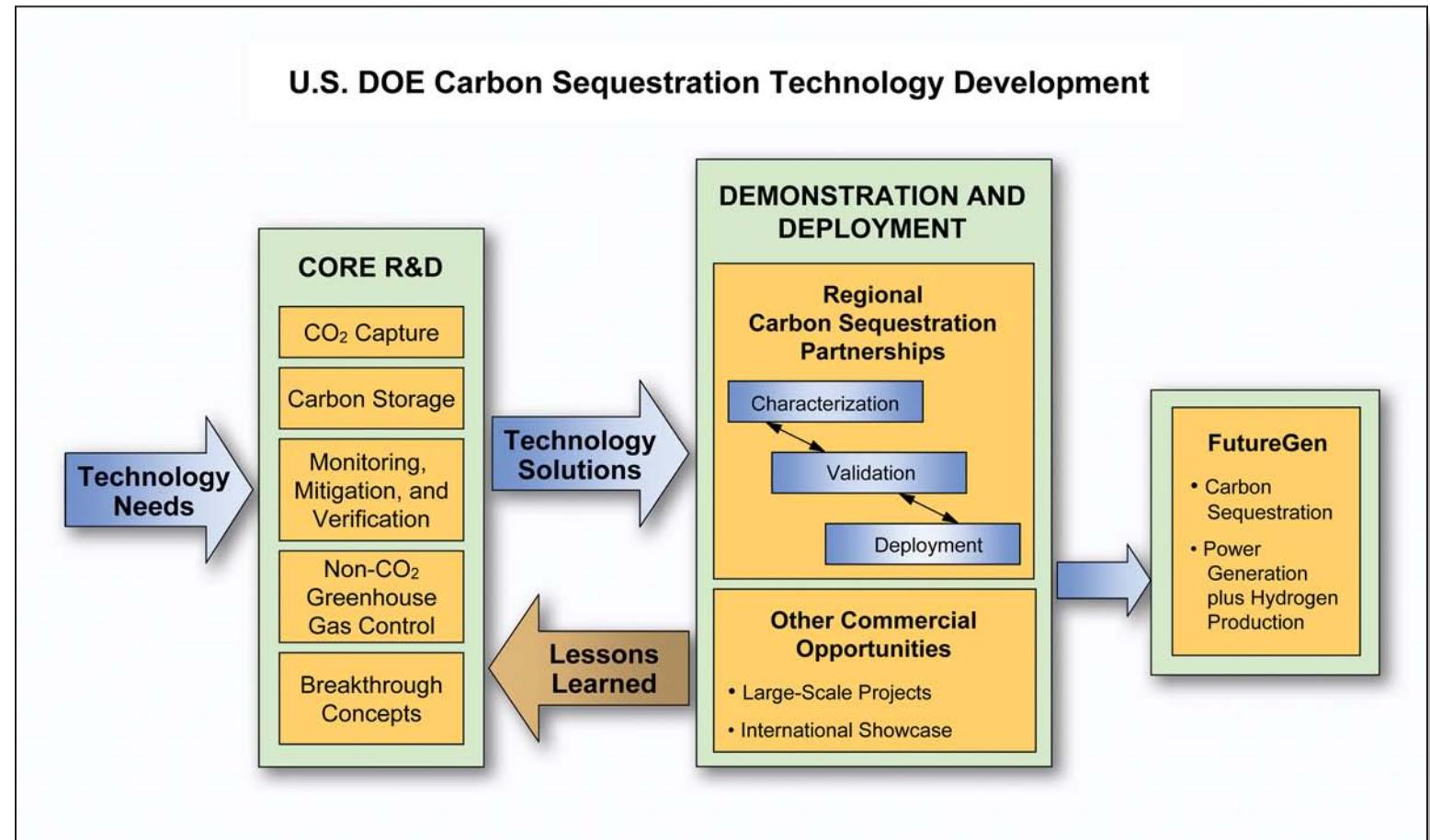


## DOE's Carbon Sequestration Program

DOE's Carbon Sequestration Program involves two key elements for technology development: (1) Core R&D and (2) Demonstration and Deployment. The Core R&D element contains five focal areas for carbon sequestration technology development: (1) CO<sub>2</sub> Capture, (2) Carbon Storage, (3) Monitoring, Mitigation, and Verification, (4) Non-CO<sub>2</sub> Greenhouse Gas Control, and (5) Breakthrough Concepts. Core R&D is driven by industry's technology needs and is accomplished through laboratory and pilot-scale research aimed at developing new technologies and new systems for GHG mitigation. Core R&D provides technology solutions which support Demonstration and Deployment in the areas of Regional Carbon Sequestration Partnerships, FutureGen, and other commercial opportunities. Experiences with Demonstration and Deployment provide "lessons learned" which are used by Core R&D in developing further technology solutions.

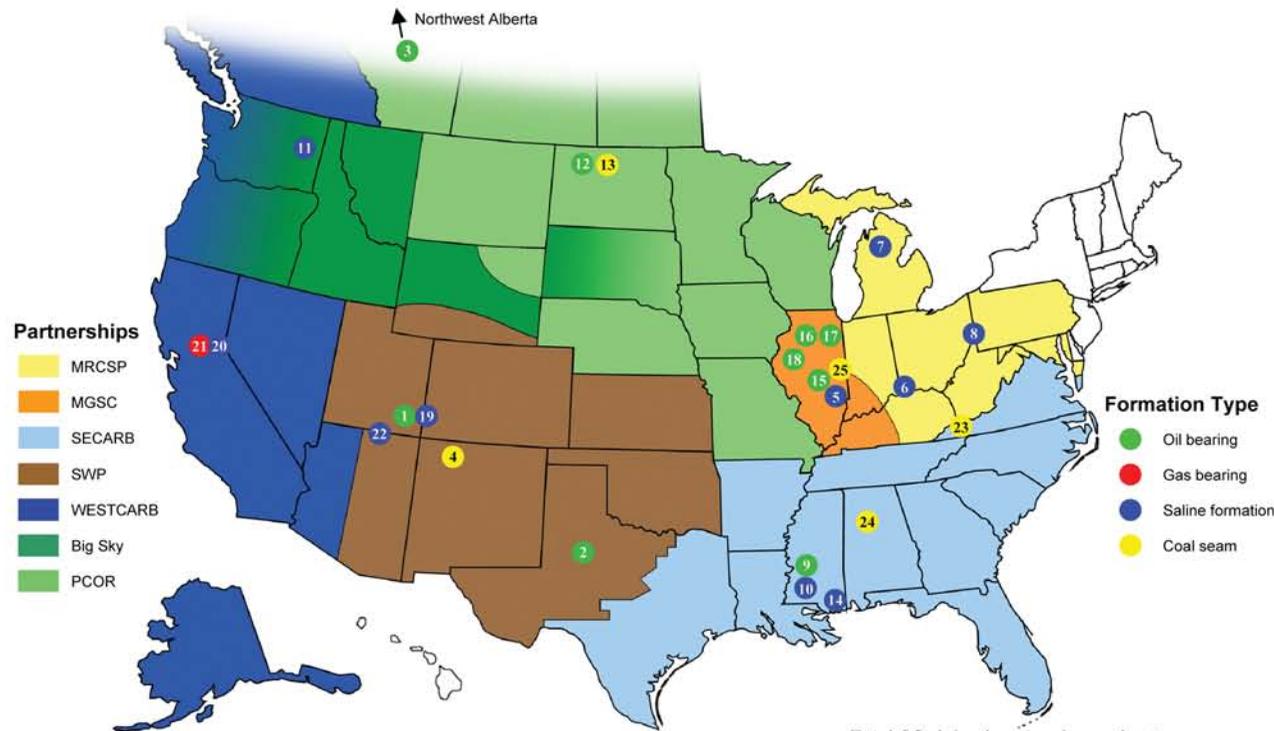
In addition, DOE is part of an international collaboration in the area of carbon sequestration, participating in the Carbon Sequestration Leadership Forum (CSLF). The CSLF is an international climate change initiative that is focused on the development of improved, cost-effective technologies for the separation and capture of CO<sub>2</sub> and for its transport and long-term safe storage. 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.

DOE's Carbon Sequestration Program is developing a portfolio of technologies with great potential to reduce GHG emissions. The Carbon Sequestration Program's primary concentration is on dramatically lowering the cost and energy requirements of pre- and post-combustion CO<sub>2</sub> capture. The 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. In the long-term, the Program is expected to contribute significantly to the President's goal of developing technologies to substantially reduce GHG emissions.



Artist rendition of FutureGen—a billion-dollar, 10-year project to create the world's first coal-based, near zero emission electricity plant with carbon capture and sequestration.

**Regional Carbon Sequestration Partnerships**  
Validation Phase Geologic Field Tests



Partnership	Geologic Province	Formation Type	Total CO <sub>2</sub> Injection (tons CO <sub>2</sub> )	Approximate Depth (feet)	
1	SWP	Paradox Basin, Aneth Field	Oil-bearing	450,000 – 750,000	5,600 – 5,800
2	SWP	Permian Basin	Oil-bearing	900,000	5,800
3	PCOR	Keg River Formation	Oil-bearing	250,000 tons CO <sub>2</sub> w/90,000 tons H <sub>2</sub> S	5,000
4	SWP	San Juan Basin	Coal seam	75,000	3,000
5	MGSC	Illinois Basin	Saline formation	10,000	7,000 – 8,600
6	MRCSP	Cincinnati Arch	Saline formation	1,000 – 3,000	3,200 – 3,500
7	MRCSP	Michigan Basin	Saline formation	3,000 – 20,000	3,200 – 3,500
8	MRCSP	Appalachian Basin	Saline formation	1,000 – 3,000	5,900 – 8,300
9	SECARB	Gulf Coast	Oil-bearing	>800,000/yr	10,066
10	SECARB	Gulf Coast	Saline formation	30,000	10,300
11	Big Sky	Columbia Basin	Saline formation (basalt/mafic)	3,000	3,255 – 3,335 & 3,600 – 3,755
12	PCOR	Duperow Formation	Oil-bearing	5,000	10,000 – 10,500
13	PCOR	Williston Basin	Coal seam	<1,000	1,600 – 1,800
14	SECARB	Mississippi Salt Basin	Saline formation	3,000	8,600
15	MGSC	Illinois Basin	Oil-bearing – Heavy	300	1,550
16	MGSC	Illinois Basin	Oil-bearing – Well Conversion	300	1,549
17	MGSC	Illinois Basin	Oil-bearing – Pattern Flood I	300	1,548
18	MGSC	Illinois Basin	Oil-bearing – Pattern Flood II	300	1,551
19	SWP	Paradox Basin, Aneth Field	Saline formation	20,000	6,900
20	WESTCARB	Thorton Gas Field	Saline formation	1,000	3,400 – 3,500
21	WESTCARB	Thorton Gas Field	Gas-bearing	500	3,050
22	WESTCARB	Colorado Plateau	Saline formation	2,000	5,000
23	SECARB	Central Appalachian	Coal seam	1,000	1,600 – 2,300
24	SECARB	Black Warrior Basin	Coal seam	1,000	1,500 – 2,500
25	MGSC	Illinois Basin	Coal seam	750	1,000

## Regional Carbon Sequestration Partnerships

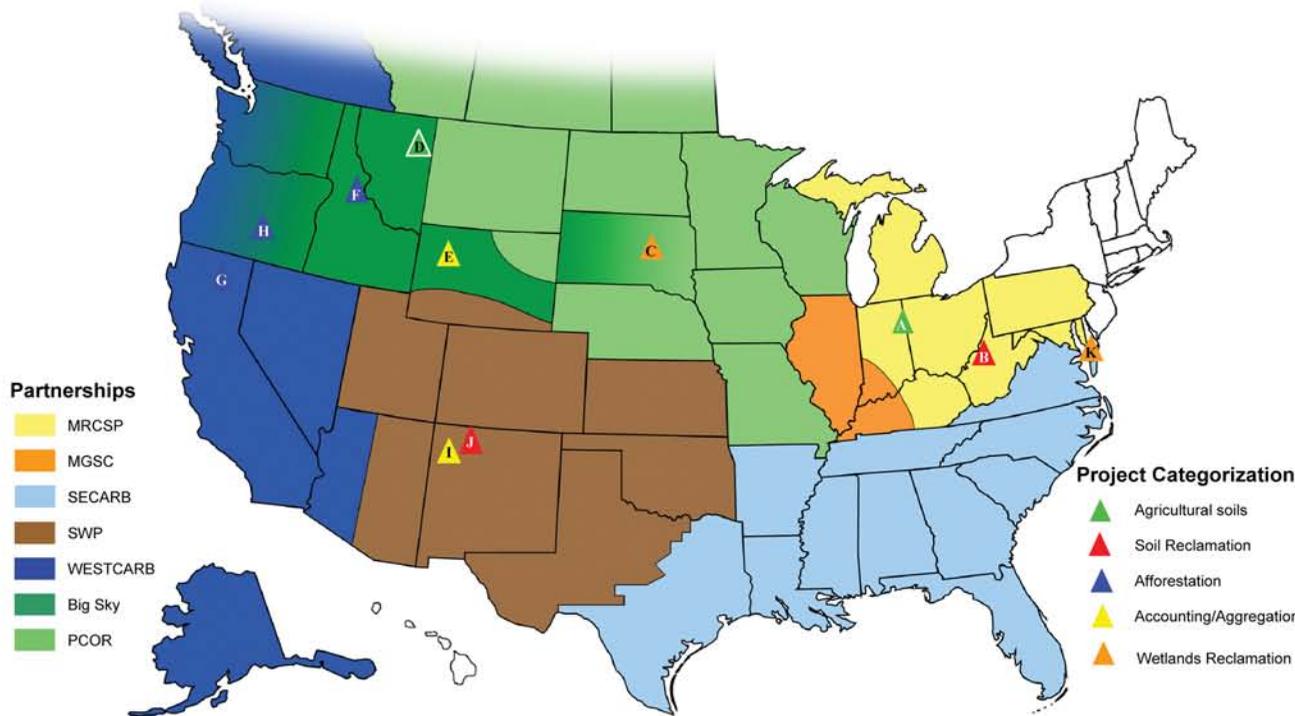
Formed by DOE, the Regional Carbon Sequestration Partnerships (RCSPs) are a government/industry effort tasked with determining the most suitable technologies, regulations, and infrastructure needs for carbon capture and sequestration in different regions of the U.S. and Canada. The energy sectors of both countries are very closely related. Geographical differences in fossil fuel use and sequestration potential across the U.S. and Canada dictate regional approaches to sequestration of CO<sub>2</sub> and other GHGs. The seven RCSPs that form this network currently include more than 350 state agencies, universities, and private companies, spanning 40 states, three Indian nations, and four Canadian provinces. In addition, agencies from six member countries of the CSLF are participating.

The RCSPs' effort has three distinct phases: (1) Characterization Phase (2003-2005); (2) Validation Phase (2005-2009); and (3) Deployment Phase (2008-2017). The Characterization Phase began in September 2003 with seven RCSPs working to develop the necessary framework to validate and potentially deploy carbon sequestration technologies. At the end of the Characterization Phase, the RCSPs had succeeded in establishing a national network of companies and professionals working to support sequestration deployments, creating a National Carbon Sequestration Database and Geographic Information System (NATCARB), and raising awareness and support for carbon sequestration as a GHG mitigation option.

The Validation Phase focuses on validating the most promising regional opportunities to deploy sequestration technologies by building upon the Characterization Phase accomplishments. Two different sequestration approaches are being pursued in this phase: geologic and terrestrial sequestration. Efforts are being made to validate and refine current reservoir simulation for CO<sub>2</sub> injection; collect physical data to confirm capacity and injectivity estimates; demonstrate the effectiveness of MM&V technologies; develop guidelines for well completion, operations, and abandonment; and develop strategies to optimize the storage capacity of various sink types.

The Deployment Phase will consist of several large-volume sequestration tests. These tests are designed to demonstrate that sequestration sites have the potential to store hundreds of years of regional CO<sub>2</sub> emissions. The large-volume sequestration tests in this phase will be conducted to address issues such as sustainable injectivity, well design for both integrity and increased capacity, and formation behavior with respect to prolonged injection.

**Regional Carbon Sequestration Partnerships**  
Validation Phase Terrestrial Field Tests



Partnership	Project Location	Land Categorization	Project Summary	Estimated CO <sub>2</sub> Capacity
MRCSP	Region-wide	Agricultural	Demonstrating carbon sequestration on existing farm lands. Determine rate of sequestration and potential for different tillage practices to increase storage.	250 Mt over 20 years
MRCSP	Region-wide	Mineland	Demonstrating carbon sequestration in reclaimed mine soils. Determine reclamation and land management practices that increase storage.	100 Mt over 20 years
PCOR	Great Plains wetlands complex (PPR)	Wetlands	Sequestration demonstration in wetlands/grasslands that will provide carbon offsets, develop protocols and standards, and provide a market-based carbon sequestration strategy.	14.4 Mt
Big Sky	North Central MT	Agricultural	Objectives are to (1) quantify and determine cropland management practices that optimize carbon sequestration and (2) develop MMV protocols to evaluate carbon sequestration for enrolled farms.	60 Mt over 20 years
Big Sky	Eastern WY	Rangeland	To determine the sequestration effects of (1) grazing intensity and seasonality of grazing on native northern mixed grass prairie and (2) improvement practices on degraded northern mixed-grass prairie.	30 Mt over 10 years
Big Sky	Region-wide	Forest	Identify strategies for maintaining or increasing sequestration in forests through understanding the effects of forest management on different carbon pools in forests.	640-1,040 Mt over 80 years
WESTCARB	Shasta County, CA	Forest and Rangelands	Validation of forest growth potential for rangelands; Change in forest management; Fuels management to reduce risk of uncharacteristically severe wildfire and prevent emissions	4,600 Mt over 80 years (CA)
WESTCARB	Lake County, OR	Forest and Rangelands	Afforestation using fast-growing tree species Fuels management to reduce risk of uncharacteristically severe wildfire and prevent emissions	900 Mt over 80 years (OR)
SWP	Region-wide	Multiple	Develop a carbon reporting and monitoring system that functions consistently across hierarchical scales and is compatible with the existing technology underlying the 1605b reporting system. Project will develop improved technologies and systems for direct measurement.	TBD
SWP	San Juan Basin Coal Fairway (Navajo City, NM)	Rangeland/ Riparian	Desalinate produced water from the ECBM pilot and use the water for irrigating a riparian restoration project. Reintroducing woody plant species along riparian areas and reestablishing native grasses and shrubs in upland areas. Project represents a combined ECBM-terrestrial sequestration project.	TBD
MRCSP	Cambridge, MD	Wetlands	Develop estimates of carbon sequestration rates in marshes over time. Understand influences of carbon management practices on sequestration rates. Develop sampling protocol for sequestration validation.	TBD

**Regional Carbon Sequestration Partnerships**

	Montana State University <a href="http://www.bigskyco2.org/">http://www.bigskyco2.org/</a>
	Illinois State Geological Survey <a href="http://www.sequestration.org/">http://www.sequestration.org/</a>
	Battelle Memorial Institute <a href="http://www.mrcsp.org">http://www.mrcsp.org</a>
	University of North Dakota, Energy & Environmental Research Center <a href="http://www.undeerc.org/pcor/">http://www.undeerc.org/pcor/</a>
	Southern States Energy Board <a href="http://www.secarbon.org/">http://www.secarbon.org/</a>
	New Mexico Institute of Mining and Technology <a href="http://www.southwestcarbonpartnership.org/">http://www.southwestcarbonpartnership.org/</a>
	California Energy Commission <a href="http://www.westcarb.org/">http://www.westcarb.org/</a>

# National Carbon Sequestration Database and Geographical Information System



## *A National Look at Carbon Sequestration*

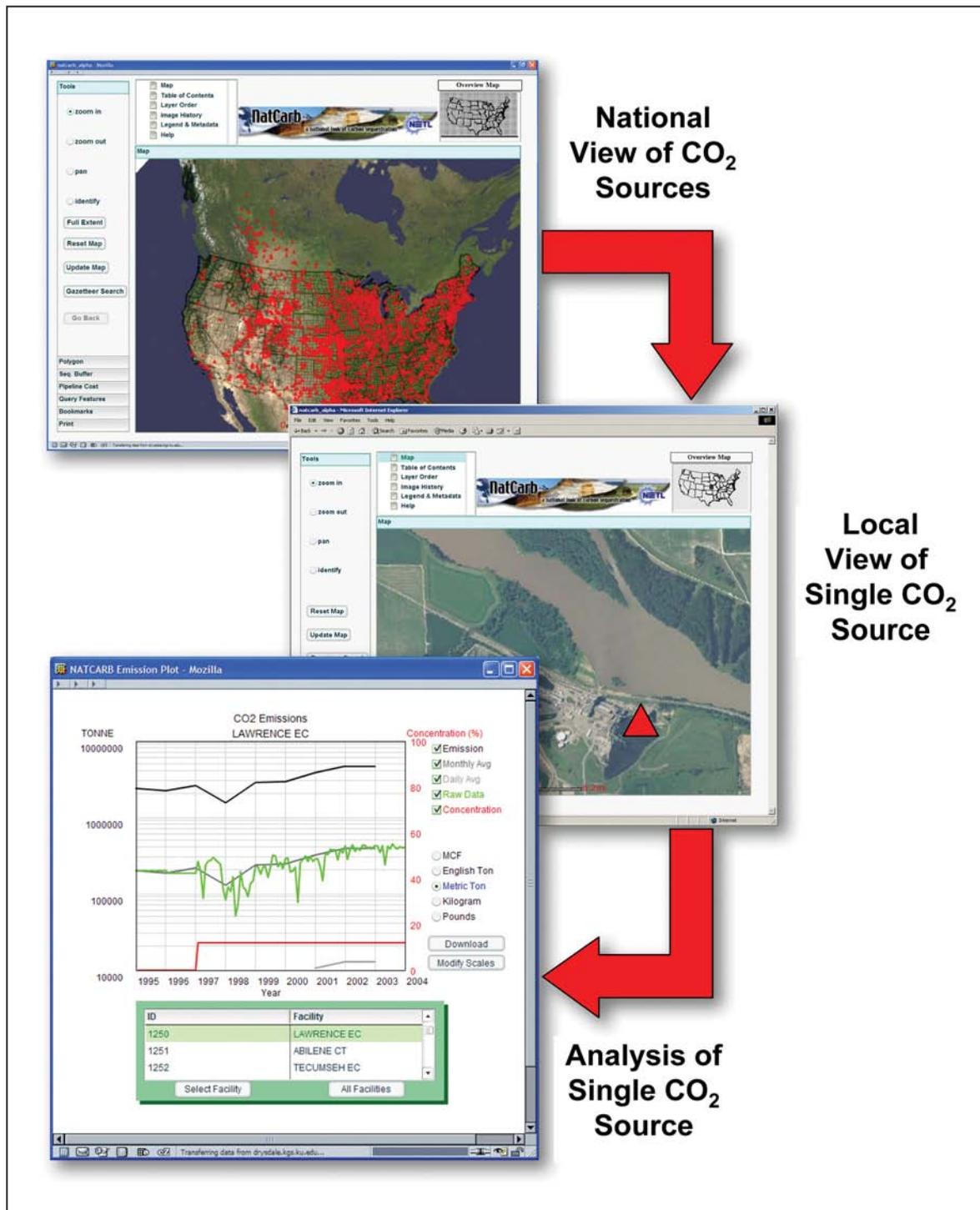
The DOE's Regional Carbon Sequestration Partnerships generated data for this *Atlas*. These key geospatial data (carbon sources, potential sequestration sites, transportation, land use, etc.) are required for efficient implementation of carbon sequestration on a broad scale. NATCARB is a relational database and 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 carbon sequestration potential in the U.S. and Canada. The digital spatial database allows users to estimate the amount of CO<sub>2</sub> emitted by sources (such as power plants, refineries and other fossil-fuel-consuming industries) in relation to geologic formations that can provide safe, secure sequestration sites over long periods of time. The NATCARB project will provide stakeholders with improved online tools for the display and analysis of CO<sub>2</sub> sequestration data.

NATCARB is organizing and enhancing the critical information about CO<sub>2</sub> sources and developing the technology needed to access, query, model, analyze, display, and distribute natural resource data related to carbon management. These data are maintained and enhanced locally at the RCSP level, or at specialized data warehouses, and assembled, accessed, and analyzed 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 national carbon cyber infrastructure. NATCARB can provide access to the necessary information regarding the costs, economic potential, and societal issues of CO<sub>2</sub> capture and storage, including public perception and regulatory aspects.

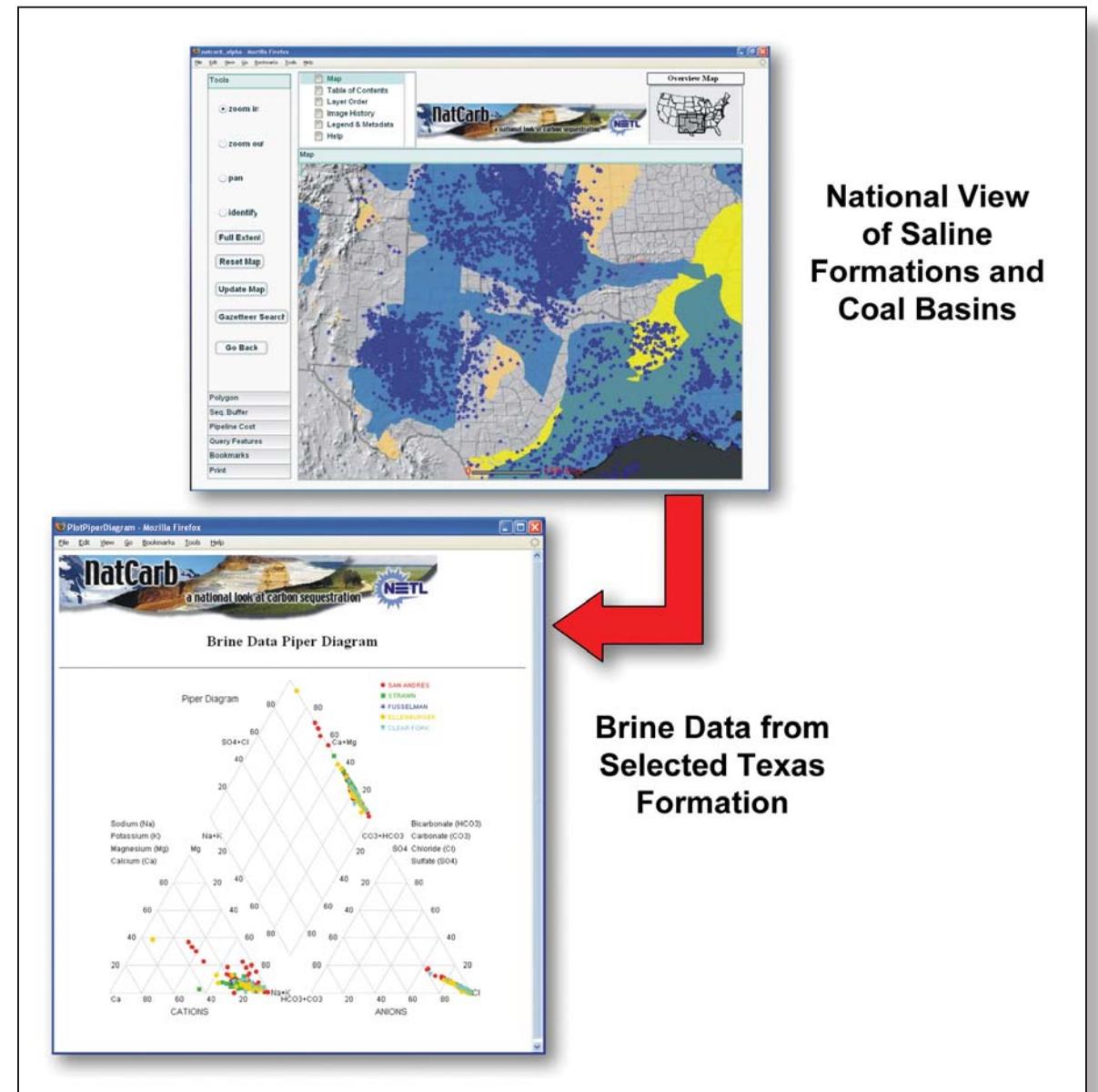
Not only is NATCARB connected to all the RCSPs, but data are also pulled from public servers including the U.S. Geological Survey-EROS Data Center and from the Geography Network. Data for major CO<sub>2</sub> sources have been obtained from U.S. Environmental Protection Agency (EPA) databases, and data on major coal basins and coalbed methane wells were obtained from the Energy Information Administration (EIA).

# Introduction

NATCARB ([www.natcarb.org](http://www.natcarb.org)) is a digital mapping site that allows users to display and analyze CO<sub>2</sub> sources and potential sequestration sites. As seen in these images, this analysis can be done at the national, regional, and local level. The CO<sub>2</sub> Source example shows all the large stationary sources of CO<sub>2</sub> across the RCSPs Regions and detailed image and display of CO<sub>2</sub> emissions from a single source. The CO<sub>2</sub> sequestration site example shows saline formations and coal basins from a national view to detailed analysis.

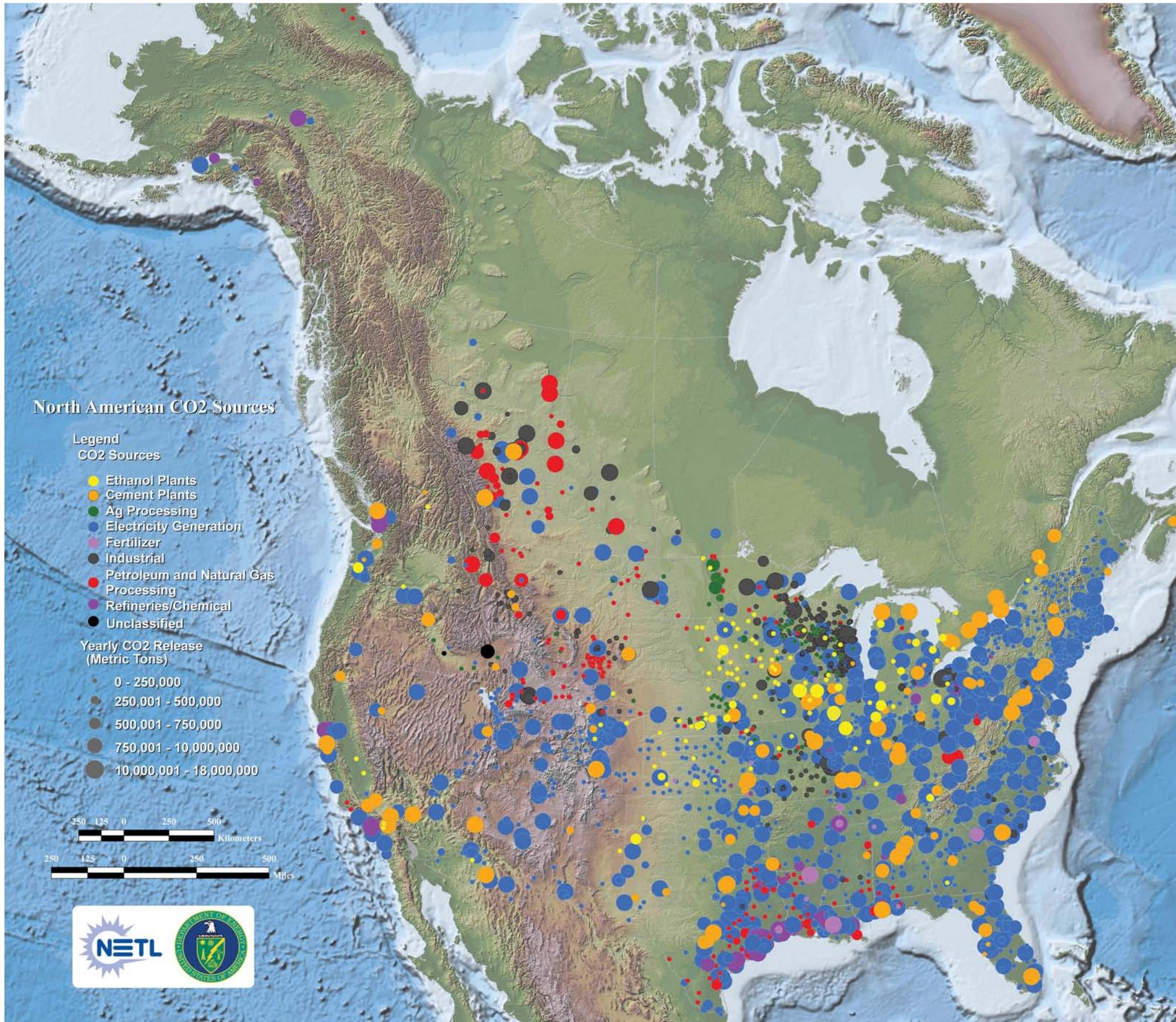


CO<sub>2</sub> Sources



CO<sub>2</sub> Sequestration Site

# National Perspectives



*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<sub>2</sub> released (see map legend).*

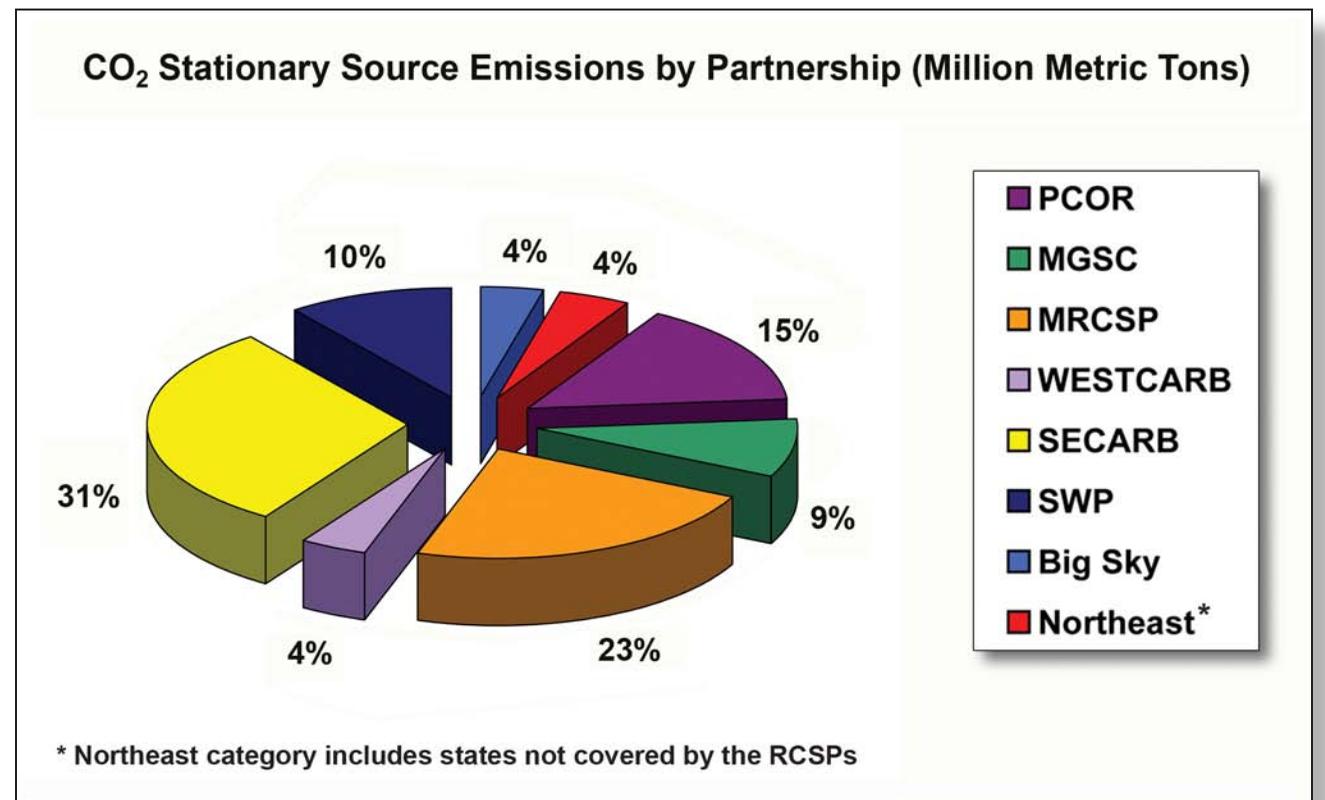
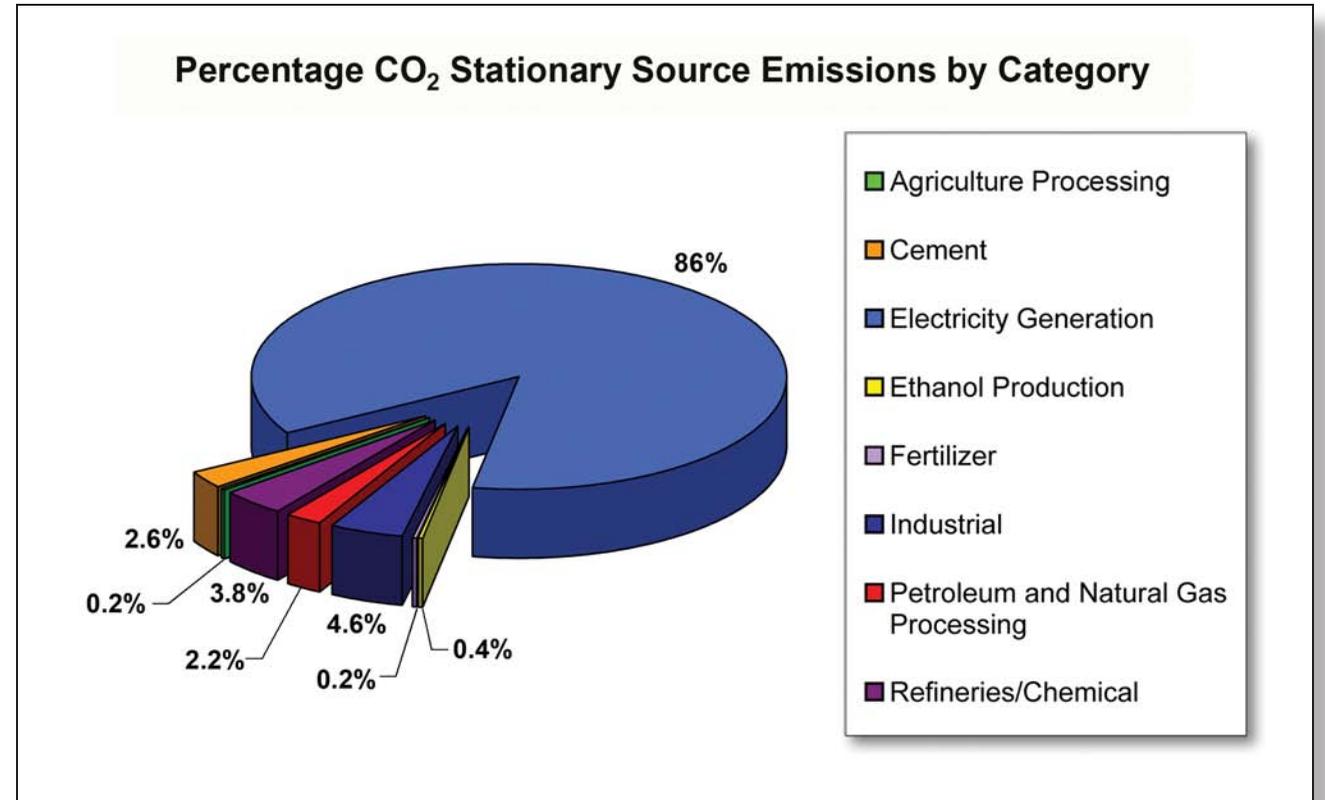
## Carbon Dioxide Sources

There are two types of CO<sub>2</sub> emission sources: stationary sources and non-stationary sources. Stationary source emissions come from a particular, identifiable, localized source, such as a power plant. CO<sub>2</sub> from stationary sources can be separated from stack gas emissions and subsequently transported to a geologic sequestration injection site for subsurface storage. The “North American CO<sub>2</sub> Sources” map displays the location and relative magnitude of a variety of CO<sub>2</sub> stationary sources.

Non-stationary source emissions include CO<sub>2</sub> emissions from the transportation sector. The evolving terrestrial sequestration technologies are one way to address these emissions.

According to the EPA, in 2004, total U.S. GHG emissions were estimated at 7,074.4 million metric tons (7,798 million tons) CO<sub>2</sub> equivalent. This estimate included CO<sub>2</sub> emissions as well as other GHGs such as methane (CH<sub>4</sub>), nitrous oxide (N<sub>2</sub>O), and hydrofluorocarbons (HFCs).

The “Percentage CO<sub>2</sub> Stationary Source Emissions by Category” pie chart contains values, gathered by the RCSPs and NATCARB (illustrated on the “North American CO<sub>2</sub> Sources” map), showing that CO<sub>2</sub> stationary source emissions result largely from energy use and industrial processes. While not all potential GHG sources have been examined, NETL’s RCSPs have documented the location of more than 4,365 stationary sources with total emissions of 3,809 million metric tons of CO<sub>2</sub>. The “CO<sub>2</sub> Stationary Source Emission by Partnership” pie chart displays the amount of CO<sub>2</sub> stationary source emissions identified by each RCSP.



## Capacity Calculations for National Estimates

DOE's NETL, NATCARB, and the RCSPs worked together to establish some common assumptions and methodologies for determining CO<sub>2</sub> capacity estimates for various geologic formations. Results of this collaboration, detailed in the *Methodology for Development of Carbon Sequestration Capacity Estimates* document (available in Appendix A), are presented in this *Atlas*. The methodologies used were designed to integrate results of assessments completed by the seven RCSPs for three types of geologic formations: oil and gas formations, unmineable coal seams, and saline formations. These methodologies were developed to be consistent across North America for a wide range of data. Storage capacity methodologies are still being developed for basalt formations and organic-rich shales.

The approach used included quantification of the storage resources available at a subregional scale and application of an estimate of the efficiency at which these resources can be used for storage of CO<sub>2</sub>. Storage efficiency represents a percentage of the storage resources that can be used for storage in all formations throughout the U.S. and Canada. Monte Carlo (statistical) simulations, including ranges of uncertainty, were used to generate a low- and high-efficiency estimate, which results in estimation of a low and a high value of capacity. Capacity estimates produced using these methodologies are based on technically available capacities that have not been reduced by economic constraints, land use, or regulatory constraints. This assessment 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<sub>2</sub> injection to estimate capacity.

### Oil and Gas Reservoirs

Oil and gas reservoir storage capacity was defined as volumes of the subsurface that have hosted natural accumulations of oil and/or gas and that could, in the future, be used to store CO<sub>2</sub>. Mapping of the seal to oil and gas reservoirs is not required because the entrapment of hydrocarbons is considered evidence that a CO<sub>2</sub> containment seal is present and the associated water is assumed to be nonpotable. Minimum depth is assigned by each RCSP.

Two methods were used to estimate the CO<sub>2</sub> storage volume: (1) a volumetrics-based CO<sub>2</sub> storage estimate and (2) a production-based CO<sub>2</sub> storage estimate. The method selected by each RCSP was based on available data. No range of capacity values is proposed for oil and gas reservoirs, reflecting a relatively good understanding of volumetrics of this system. No distinction is made between reservoirs that are in production and those that are or will soon become mature or abandoned.

### Unmineable Coal Seams

The absorptive nature of coal compared with that of porous media was expected to cause the range of parameters for displacement efficiency terms to be much higher than for porous media. Gas concentration from the Langmuir isotherm was substituted for the porosity that was used in other capacity calculations. It is assumed that delineation of most coals via mapping is better than quantification of porosity distribution in saline formations; however, some unmapped heterogeneity at a basin scale was included within the estimated value of the efficiency factor. The definition of unmineable coal varies from region to region due to depth distribution of the total resource relative to the rate and cost of mining.

The CO<sub>2</sub> storage efficiency factor has several components that reflect different physical barriers that inhibit CO<sub>2</sub> from contacting 100 percent of the coal bulk volume of a given basin or region. Depending on the definitions of area, thickness, and CO<sub>2</sub> concentration, the CO<sub>2</sub> storage efficiency factor may also reflect the volumetric difference between bulk volume and coal volume.

\* Monte Carlo (statistical) simulations estimate a range for the efficiency factor between 28 and 40 percent; these values provide a 15–85 percent confidence range.

### Saline Formations

A brine (saline) formation assessed for storage was defined as a porous and permeable body of rock containing water with total dissolved solids (TDS) greater than 10,000 mg/L, which has the capacity to store large volumes of CO<sub>2</sub>. Capacities were determined for all saline formations below 2,500 ft where adequate data was available.

Assumptions used in the capacity estimate for saline formations include (1) saline formations are heterogeneous, (2) CO<sub>2</sub> storage will be under multiphase conditions, (3) only 20–80 percent of the area inventoried and 25–75 percent of the formation thickness assessed will be occupied by CO<sub>2</sub>, and (4) the efficiency factor accounts for net to effective porosity, areal displacement efficiency, vertical displacement efficiency, gravity effects, and microscopic displacement efficiency.

Saline formations assessed for storage are restricted to those where the following basic criteria for the storage are met: (1) pressure and temperature conditions in the saline formation are adequate to keep the CO<sub>2</sub> in dense phase (supercritical) or liquid phase, (2) a suitable seal is present to limit vertical flow of the CO<sub>2</sub> to the surface, and (3) salinity in the saline formation is >10,000 ppm TDS. For this capacity estimate, a depth of 2,500 feet below surface is accepted as a reasonable proxy for these criteria to be met.

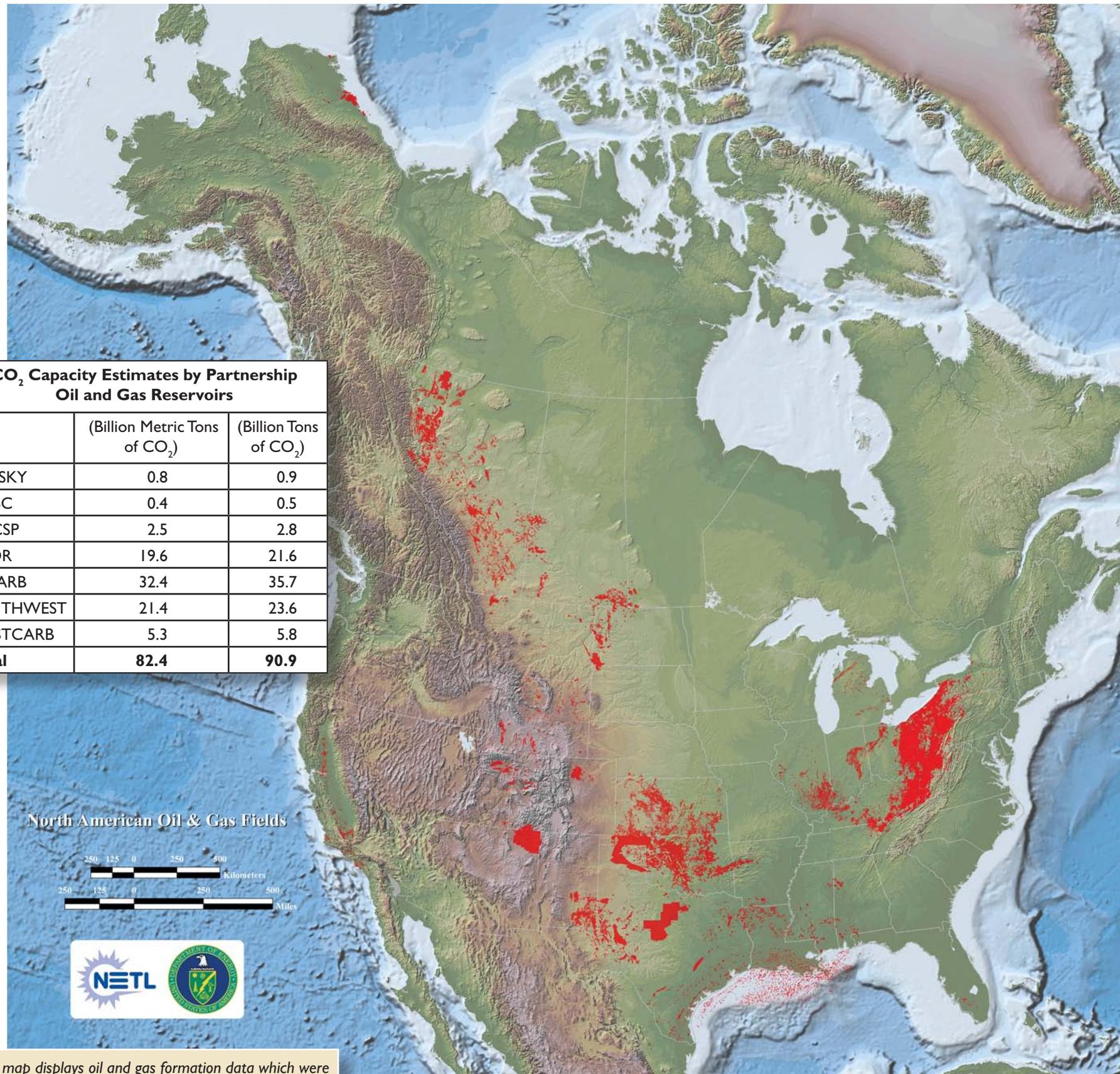
\* Monte Carlo (statistical) simulations estimate a range for the efficiency factor between 1 and 4 percent of the bulk volume of saline formations for a 15–85 percent confidence range.

## Oil and Gas Reservoirs

Mature oil and gas reservoirs 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 hydrocarbons in place. Oil and gas fields have many characteristics that make them excellent target locations for geologic storage of CO<sub>2</sub>. The geologic conditions that trap oil and gas are also the conditions that are conducive to CO<sub>2</sub> sequestration.

As a value-added benefit, CO<sub>2</sub> injected into a mature oil reservoir can enable incremental oil to be recovered. A small amount of CO<sub>2</sub> will dissolve in the oil, increasing the bulk volume and decreasing the 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). A CO<sub>2</sub> flood allows recovery of an additional 10-15 percent of the OOIP. NETL's work in this area is focused on increasing the amount of CO<sub>2</sub> that remains in the ground as part of CO<sub>2</sub> EOR injection.

While not all potential mature oil and gas reservoirs have been examined, the RCSPs have documented the location of more than 82.4 billion metric tons (90.8 billion tons) of sequestration potential in mature oil and gas reservoirs.



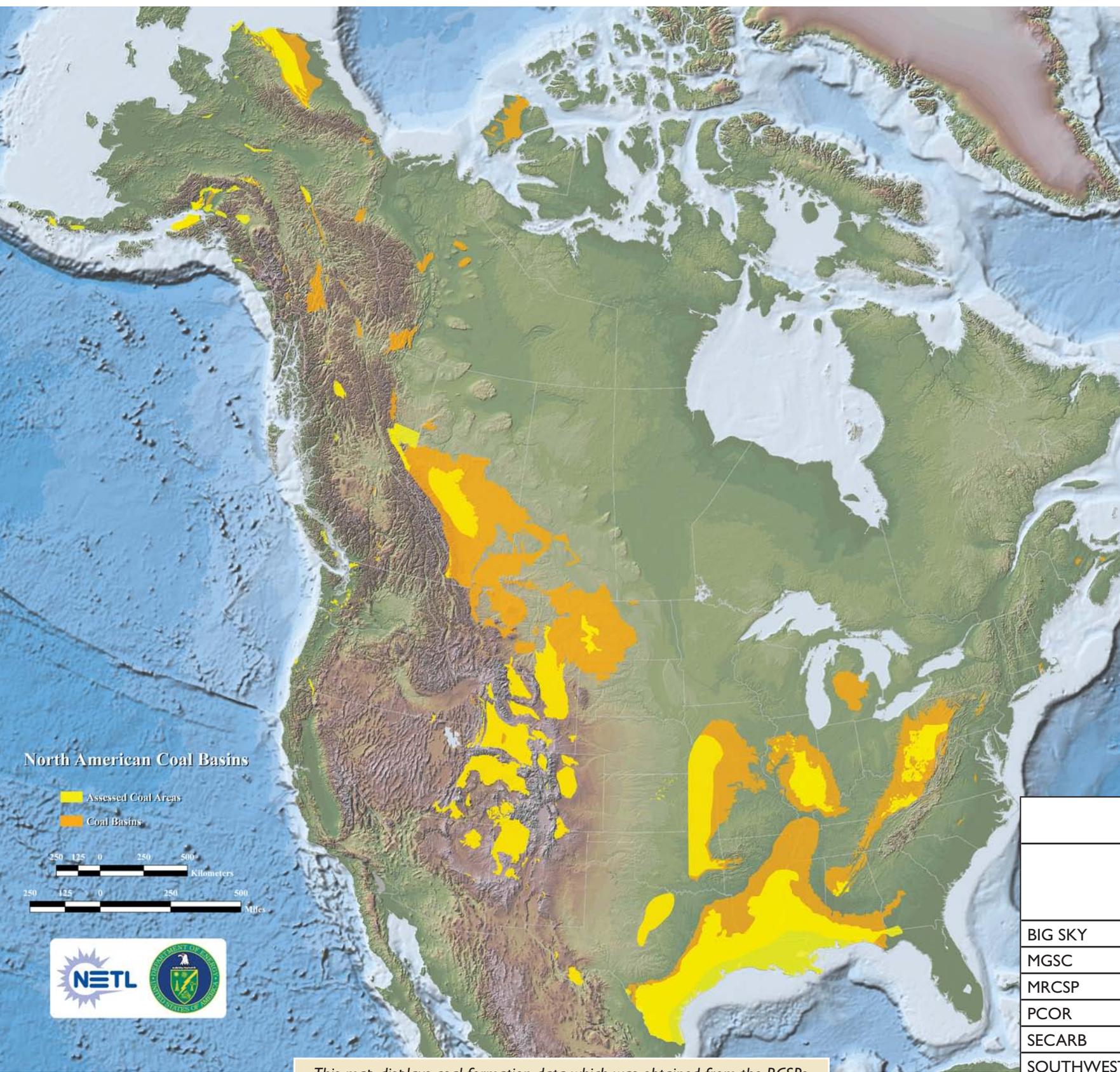
CO <sub>2</sub> Capacity Estimates by Partnership Oil and Gas Reservoirs		
	(Billion Metric Tons of CO <sub>2</sub> )	(Billion Tons of CO <sub>2</sub> )
BIG SKY	0.8	0.9
MGSC	0.4	0.5
MRCSP	2.5	2.8
PCOR	19.6	21.6
SECARB	32.4	35.7
SOUTHWEST	21.4	23.6
WESTCARB	5.3	5.8
<b>Total</b>	<b>82.4</b>	<b>90.9</b>

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

## 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<sub>2</sub>. Depending on coal rank three to thirteen molecules of CO<sub>2</sub> are adsorbed for each molecule of methane released, thereby providing an excellent storage site for CO<sub>2</sub> along with the additional benefit of enhanced coalbed methane (ECBM) recovery. Similar to maturing oil reservoirs, unmineable coalbeds are good candidates for CO<sub>2</sub> storage.

While not all potential areas of unmineable coal have been examined, the RCSPs have documented the location of 156–183 billion metric tons (172–202 billion tons) of CO<sub>2</sub> sequestration potential in unmineable coal seams.



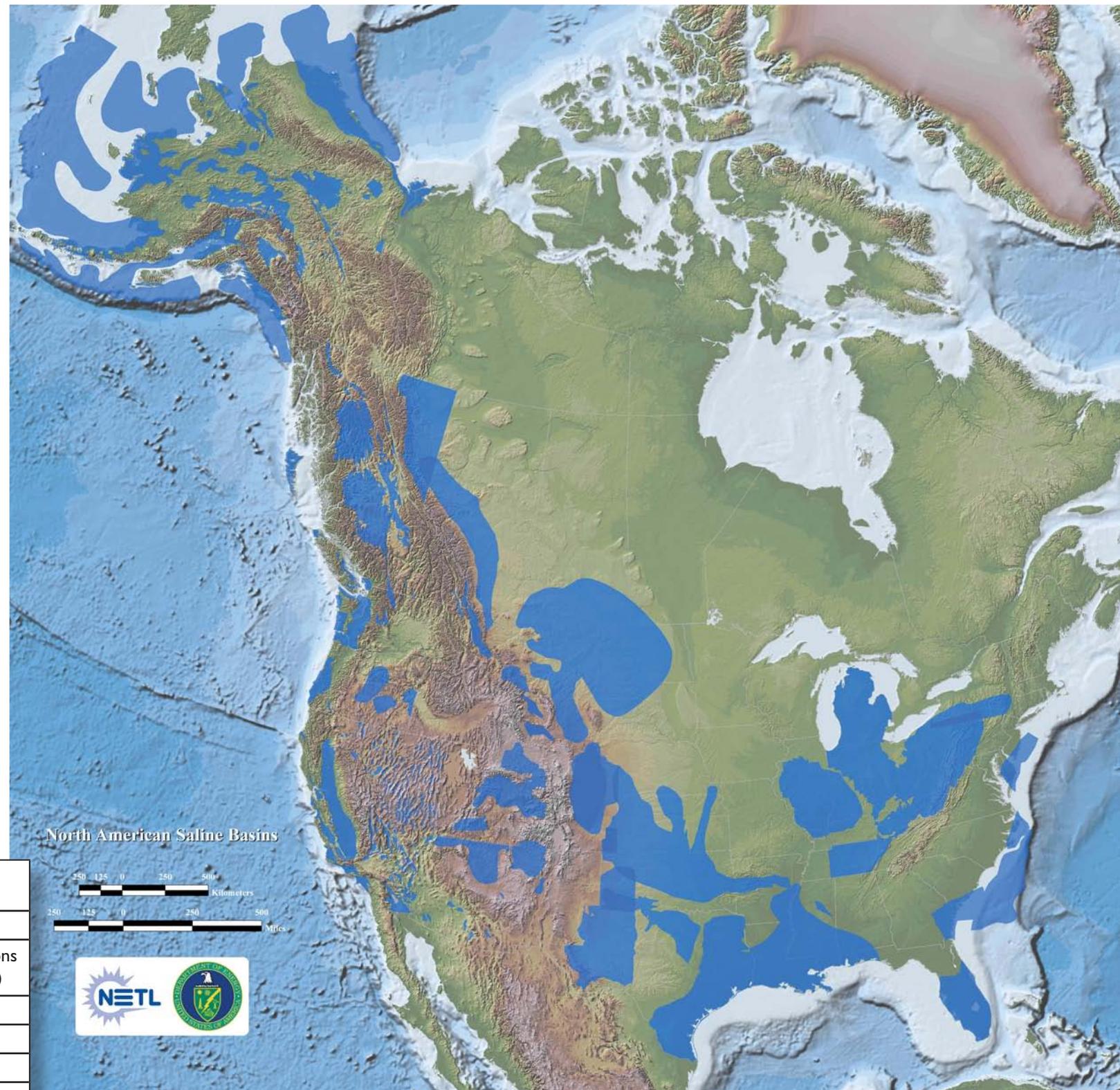
This map displays coal formation data which was obtained from the RCSPs and other external sources and compiled by NATCARB.

CO <sub>2</sub> Capacity Estimates by Partnership Unmineable Coal Seams				
	Low		High	
	(Billion Metric Tons of CO <sub>2</sub> )	(Billion Tons of CO <sub>2</sub> )	(Billion Metric Tons of CO <sub>2</sub> )	(Billion Tons of CO <sub>2</sub> )
BIG SKY	0.0	0.0	0.0	0.0
MGSC	2.3	2.5	3.3	3.6
MRCSP	0.7	0.8	1.0	1.1
PCOR	8.0	9.0	8.0	9.0
SECARB	57.4	63.3	82.1	90.5
SOUTHWEST	0.9	0.9	2.3	2.5
WESTCARB	86.8	96.1	86.8	96.1
<b>Total</b>	<b>156.1</b>	<b>172.6</b>	<b>183.5</b>	<b>202.8</b>

## 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<sub>2</sub> 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<sub>2</sub> storage.

While not all saline formations in the U.S have been examined, the RCSPs have documented the locations of such formations with an estimated sequestration potential ranging from 919 to more than 3,300 billion metric tons (from 1,014 to more than 3,700 billion tons) of CO<sub>2</sub>.



CO <sub>2</sub> Capacity Estimates by Partnership Saline Formations				
	Low		High	
	(Billion Metric Tons of CO <sub>2</sub> )	(Billion Tons of CO <sub>2</sub> )	(Billion Metric Tons of CO <sub>2</sub> )	(Billion Tons of CO <sub>2</sub> )
BIG SKY	271	299	1,085	1,196
MGSC	29	32	115	127
MRCSP	47	52	189	208
PCOR	97	107	97	107
SECARB	360	397	1,440	1,587
SOUTHWEST	18	20	64	71
WESTCARB	97	107	388	428
<b>Total</b>	<b>919</b>	<b>1,014</b>	<b>3,378</b>	<b>3,724</b>

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

## Future Geologic Sequestration Options

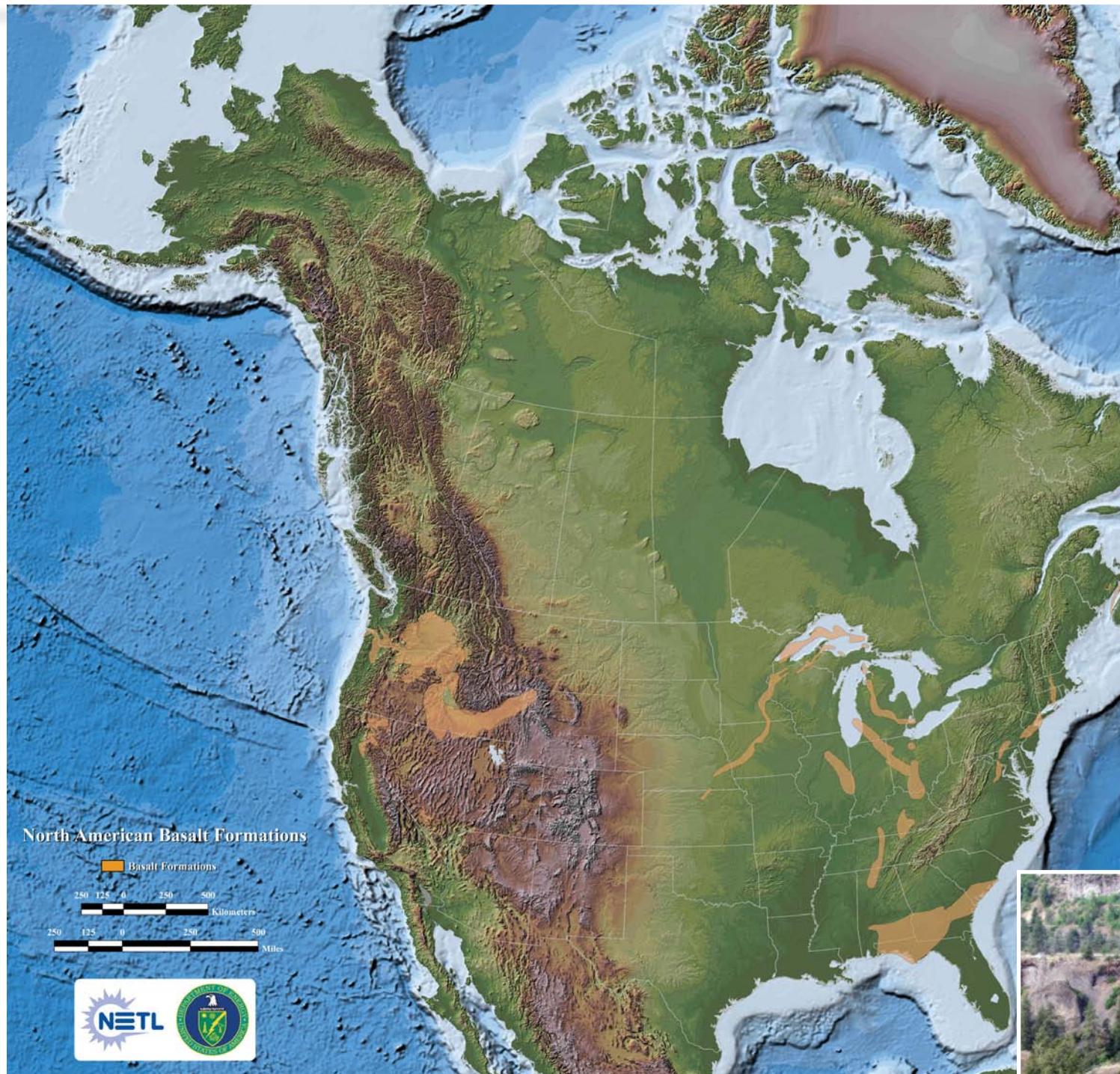
Other possible geologic sequestration options include basalts and shale formations.

### Basalt Formations

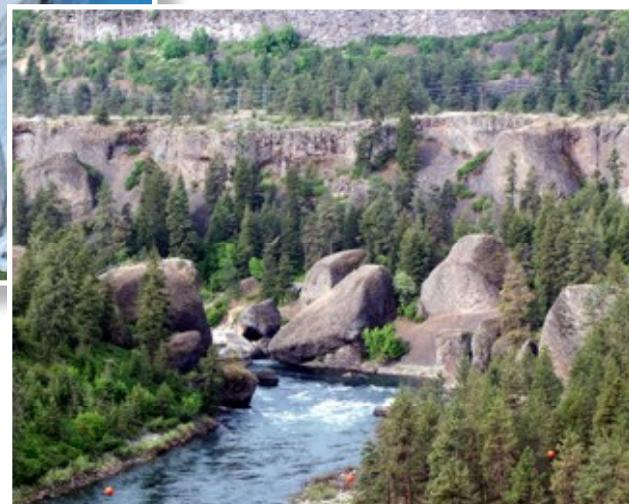
Basalt formations are geologic formations of solidified lava. Basalt formations have a unique chemical makeup that could potentially convert all of the injected CO<sub>2</sub> to a solid mineral form, thus isolating it from the atmosphere permanently. Research is focused on enhancing and utilizing the mineralization reactions and increasing CO<sub>2</sub> flow within a basalt formation.

### Organic Rich Shales

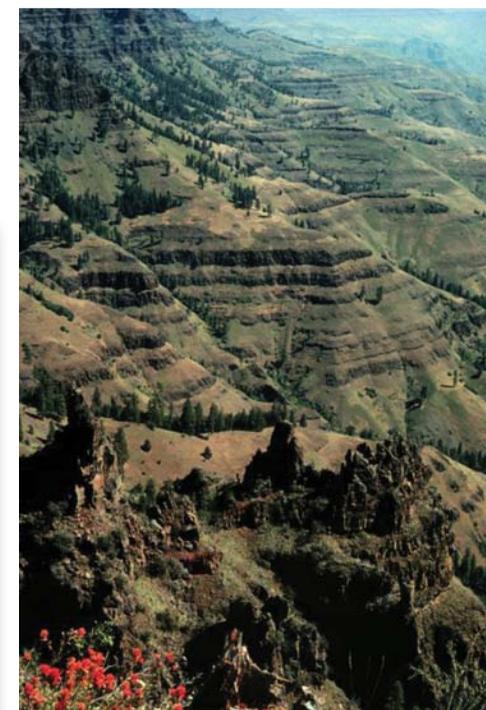
Shale, the most common type of sedimentary rock, is characterized by thin horizontal layers of rock with very low permeability in the vertical direction. Many shales contain 1–2 percent organic material in the form of hydrocarbons, which provides an adsorption substrate for CO<sub>2</sub> storage similar to CO<sub>2</sub> storage in coal seams. Research is focused on achieving economically viable CO<sub>2</sub> 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.*



*Basalt Formation*



*Columbia River Basalt*

### Terrestrial Sequestration

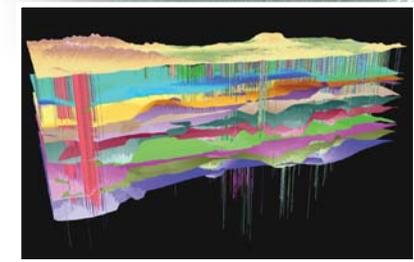
Terrestrial sequestration is CO<sub>2</sub> uptake by soils and plants, both on land and in aquatic environments such as wetlands and tidal marshes. Terrestrial sequestration provides an opportunity for low-cost CO<sub>2</sub> emissions offsets and usually offers additional benefits such as habitat or water quality improvements. Terrestrial 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. 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, U.S. EPA, and the Department of the Interior are also involved in terrestrial sequestration in supporting and complementary roles.

Afforestation on minelands provides more carbon sequestration per acre of land compared to grass planting. Tilling and soil amendment approaches provide a layer of loose earth that enables trees to take root. In some cases the tilled mineland is amended with coal combustion by-products to reduce its acidity. A layer of compacted earth is maintained under the loose earth to prevent rainwater from draining through the mine slag. These approaches can be applied to both closure practices at currently operating mines and reclamation of the nearly 6,070 km<sup>2</sup> (2,344 mi<sup>2</sup>) of lands in the U.S. damaged by past mining practices.



# Regional Carbon Sequestration Partnerships Perspectives

Information contained in the following Regional Carbon Sequestration Partnership (RSCP) Sections was obtained from each RCSP. This information was collected and analyzed as part of the Characterization and Validation Phase efforts of the RCSPs, and is not intended to be a comprehensive assessment. For additional information, please visit the RCSP websites (listed on page 7).



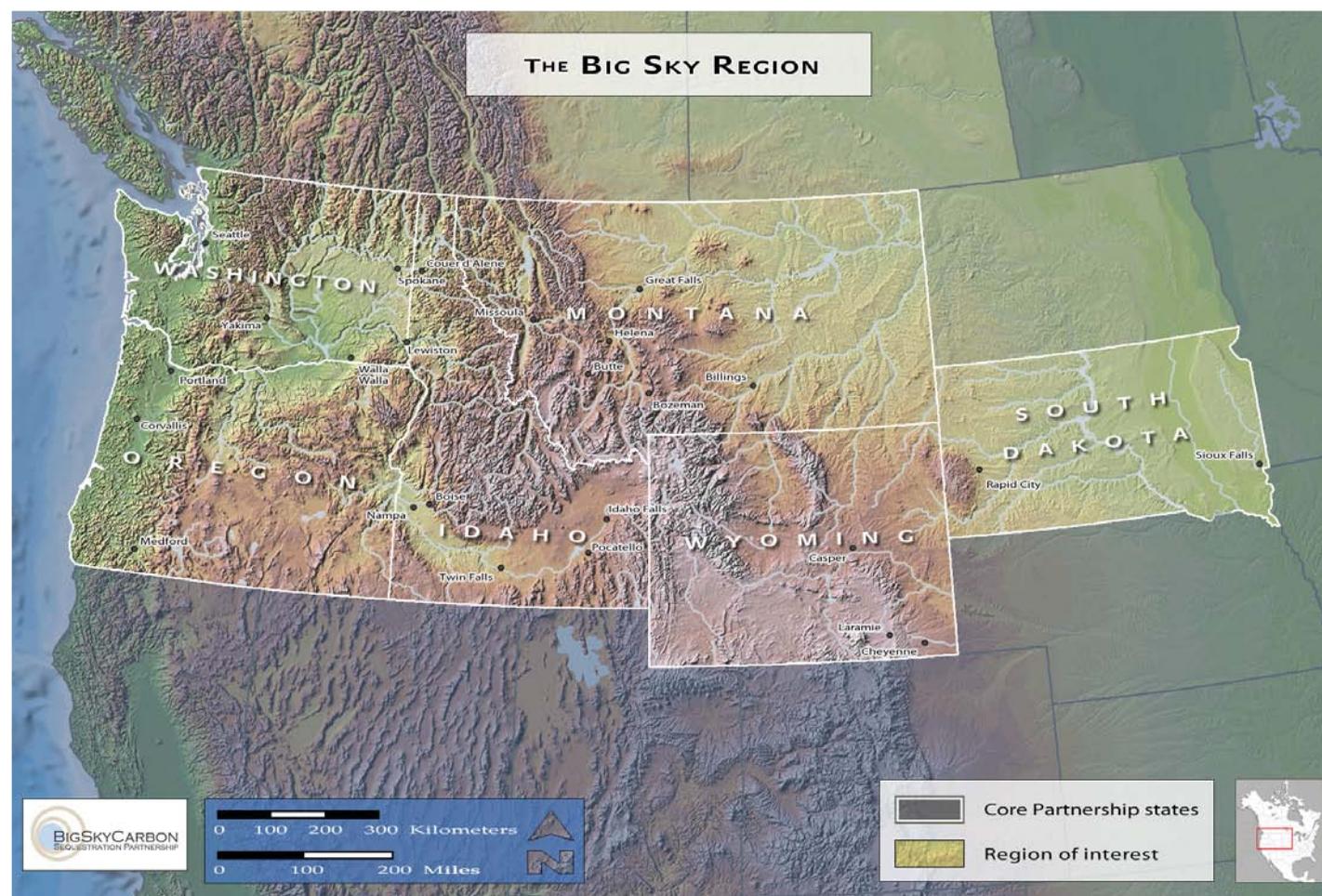
Credit: U.S. Fish and Wildlife Service

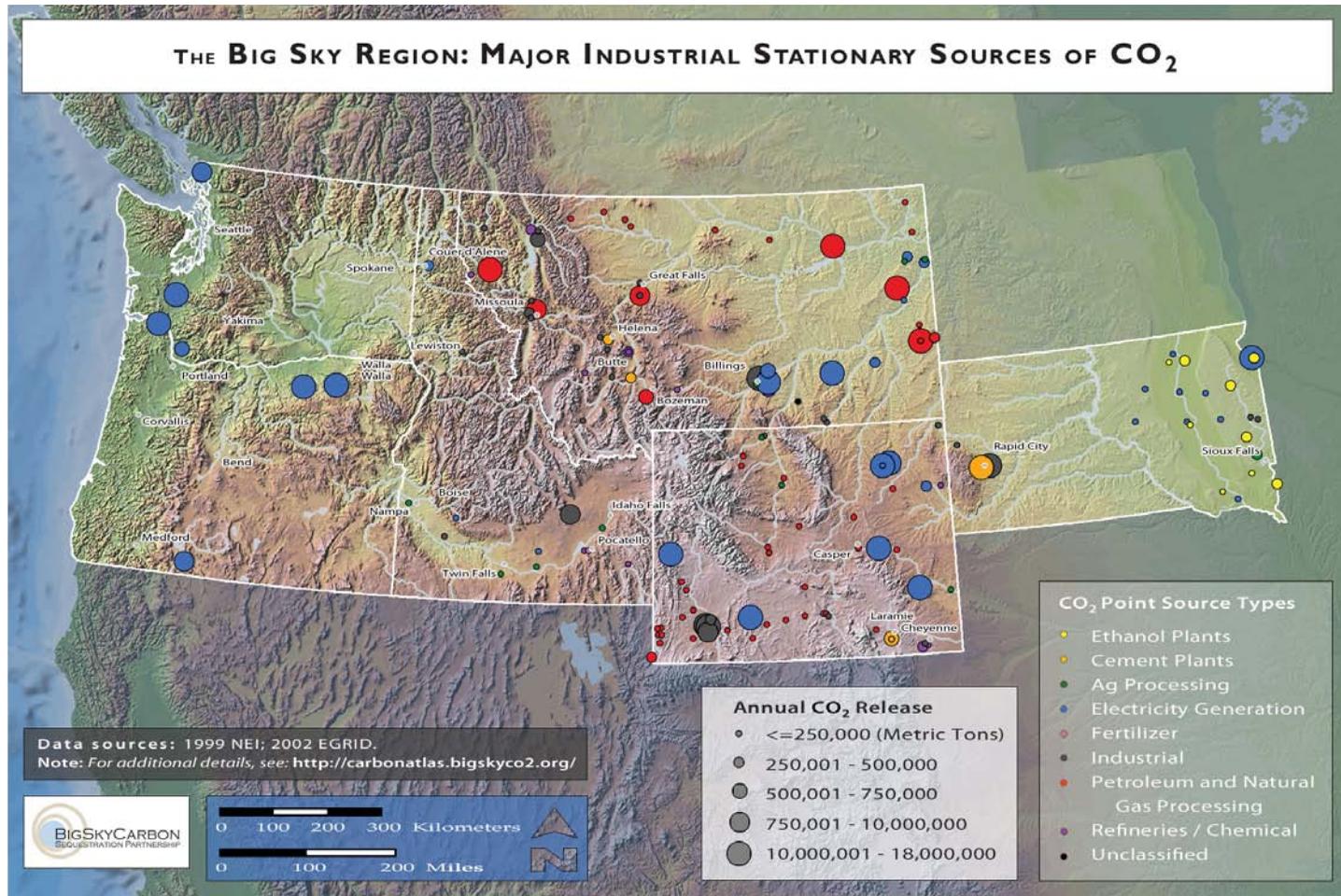
# Big Sky Carbon Sequestration Partnership

The Big Sky Carbon Sequestration Partnership (BSCSP) is building a new energy future for Montana, Idaho, South Dakota, Wyoming, eastern Oregon and Washington, and adjacent areas in British Columbia and Alberta. BSCSP is developing a framework to address CO<sub>2</sub> emissions and working with a diverse array of stakeholders to create the vision for a new, sustainable energy future that cleanly meets the Region's energy needs. BSCSP has the goal of developing an infrastructure to support and enable future carbon sequestration field tests and deployment throughout the BSCSP Region.

BSCSP represents a coalition of more than 60 organizations including universities and other research institutions, state and federal agencies, industry members including major power producers, carbon trading entities, state governments, outreach education partners, Tribal Nations and Councils, and international collaborators. Based at Montana State University, the BSCSP also benefits from the direct involvement of its partner institutions in Idaho.

The BSCSP Region has a diverse range of CO<sub>2</sub> sources and represents a wealth of potential carbon sequestration sites and future energy resources. Sequestration sites include large areas of mafic volcanic rocks (flood basalts), reactive carbonate reservoirs (e.g., the Madison formation), and Powder River basin coals. Potential energy resources include biomass and bioenergy alternatives, ethanol, natural gas reserves, the potential for nuclear power, and nearly 40 percent of total U.S. coal reserves.



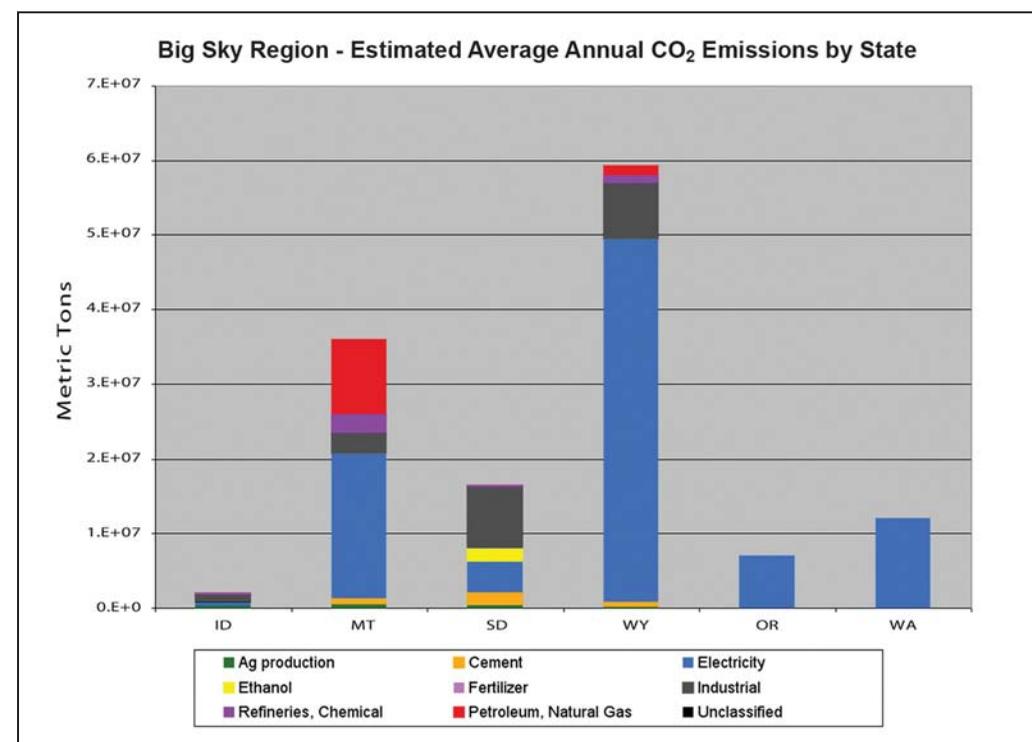


## BSCSP Stationary Sources

The BSCSP has identified and characterized major industrial stationary sources of CO<sub>2</sub> within the Region, including ethanol plants, cement plants, agriculture processing, electricity generation, fertilizer production, industrial sources, petroleum and natural gas processing, refineries/chemical sources, and other unclassified sources.

Throughout the BSCSP Region, it is estimated that an average of 134 million metric tons (147 million tons) of CO<sub>2</sub> are emitted annually.

As part of ongoing activities related to construction of this *Atlas*, work continues to adequately characterize potential geological sequestration sites in the vicinity of stationary sources. This information, in conjunction with available infrastructure (pipelines, EOR sites, etc.) will provide an interactive mapping portfolio to allow siting of future plants in proximity to appropriate geological formations and infrastructure for sequestration purposes.



Stationary source GHG emissions.

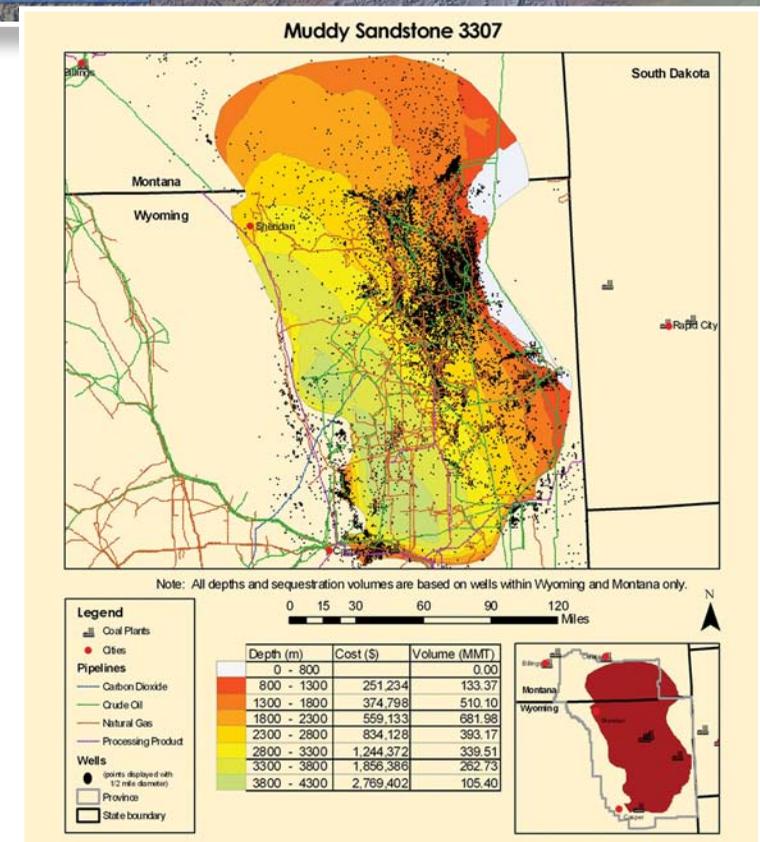
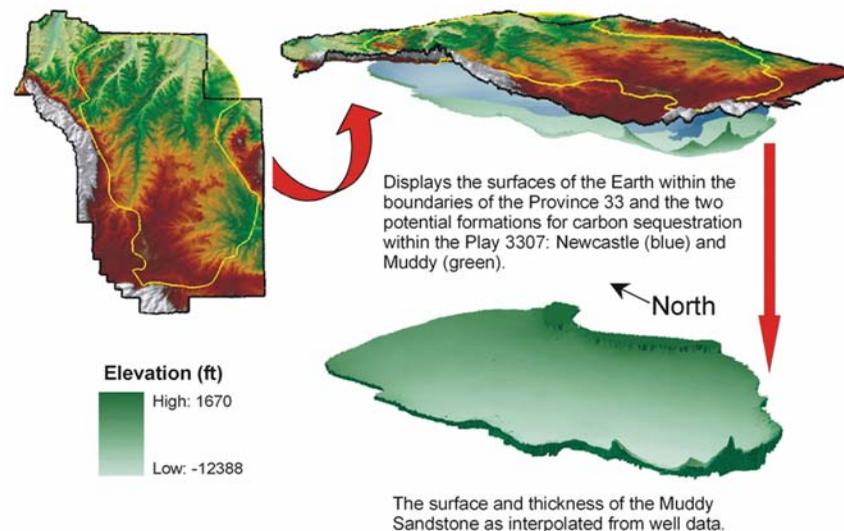
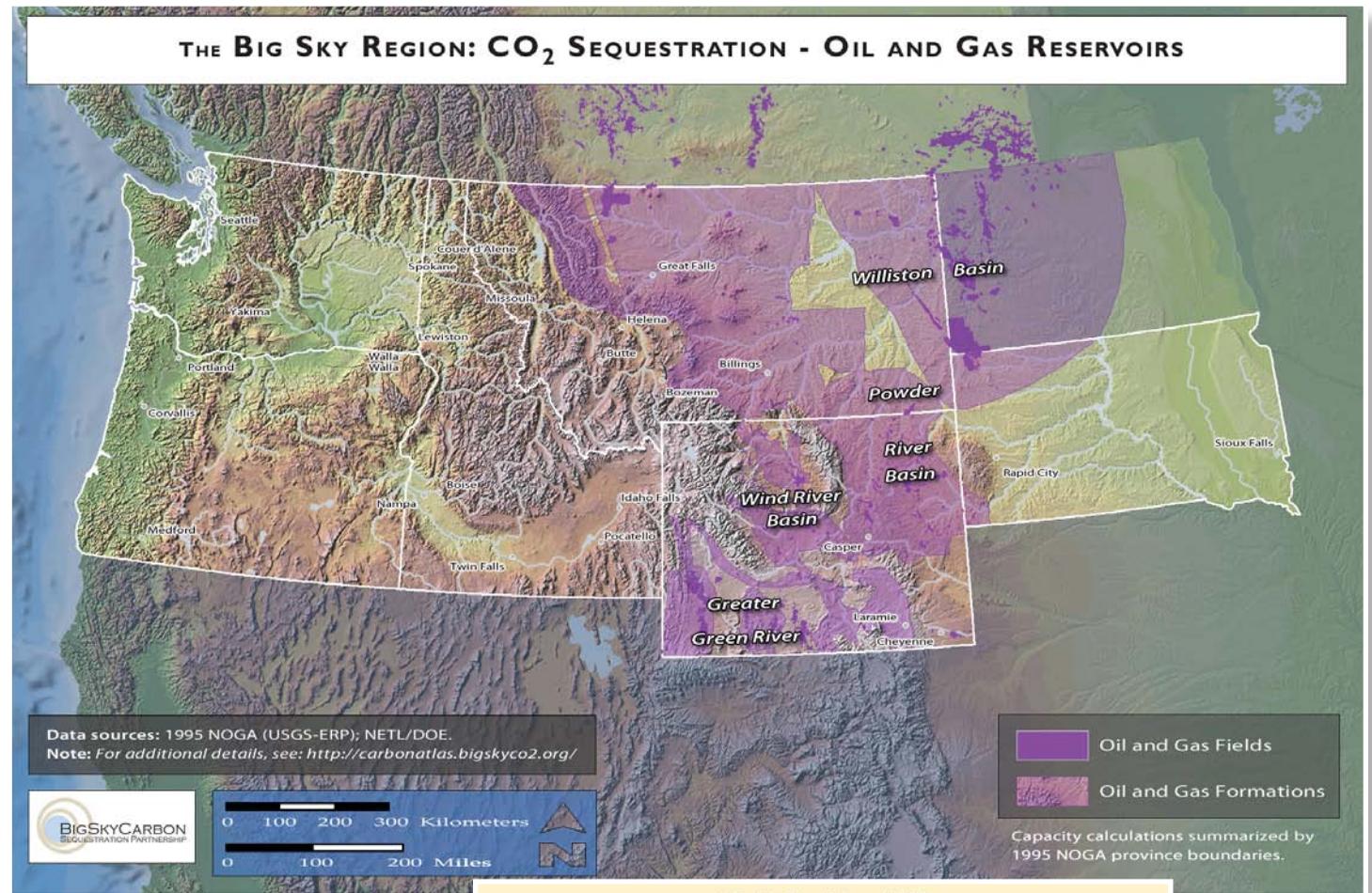
## BSCSP Oil and Gas Reservoirs

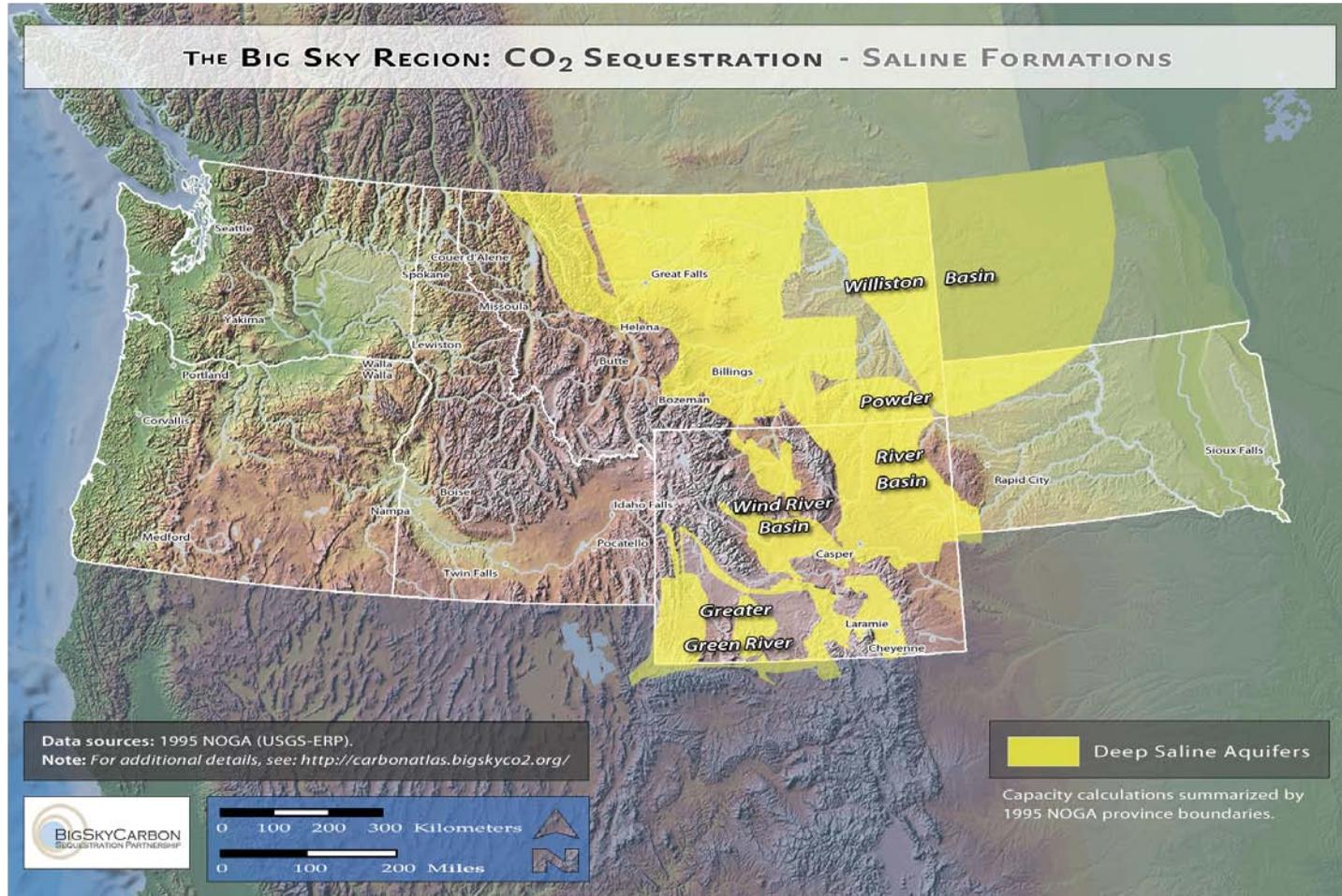
Mature oil and gas reservoirs that held crude oil and natural gas over millions of years, within the BSCSP Region, are found mostly in Wyoming and Montana and a small portion of South Dakota.

The major oil- and gas-producing basins within the Region are the Williston basin that covers the eastern edge of Montana and parts of South and North Dakota, the Wind River basin that sits completely inside Wyoming, the Powder River basin that overlaps the southeastern corner of Montana and the northwestern corner of Wyoming, and finally, the Greater Green River basin in southern Wyoming.

Three EOR operations are currently active in the Green River, Wind River and Powder River Basins utilizing CO<sub>2</sub> produced from a helium and methane gasification plant in the Green River Basin. Plans are in progress to expand the delivery of this CO<sub>2</sub> to many other fields including the Big Horn Basin, Williston Basin and Laramie Basin. The presence of large, naturally occurring CO<sub>2</sub> reservoirs in this Region further demonstrates the efficacy of use of these basins for long-term storage of CO<sub>2</sub>.

Potential carbon sequestration volumes have been developed using information from a variety of sources including existing oil and gas wells and geographic extents of oil provinces and plays. The potential volumes total just under 1 billion metric tons (1.1 billion tons) of storage space for CO<sub>2</sub>.

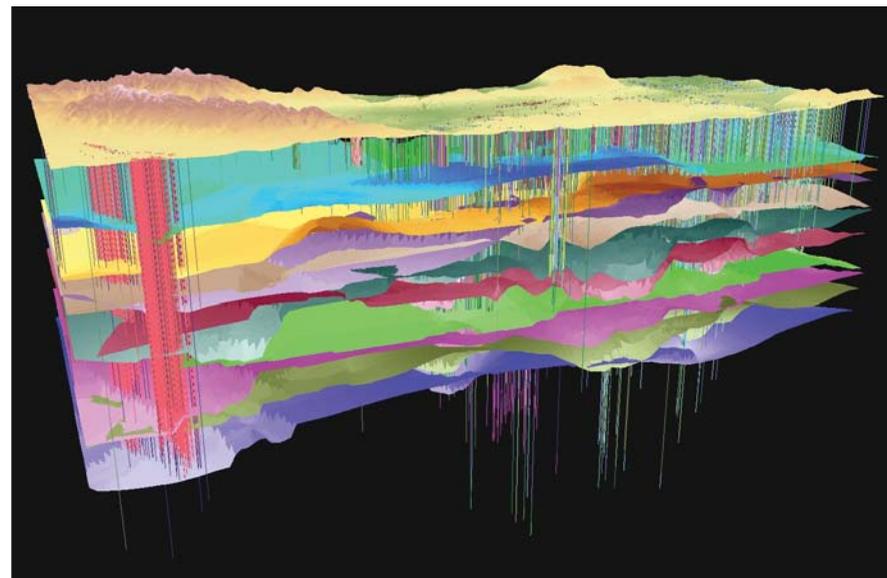




## BSCSP Saline Formations

The extent of saline formations throughout the BSCSP Region offers great potential for future sequestration activities. Many of these formations currently host vast, naturally occurring CO<sub>2</sub> reservoirs that demonstrate the potential of these areas to hold anthropogenic CO<sub>2</sub> for millions of years.

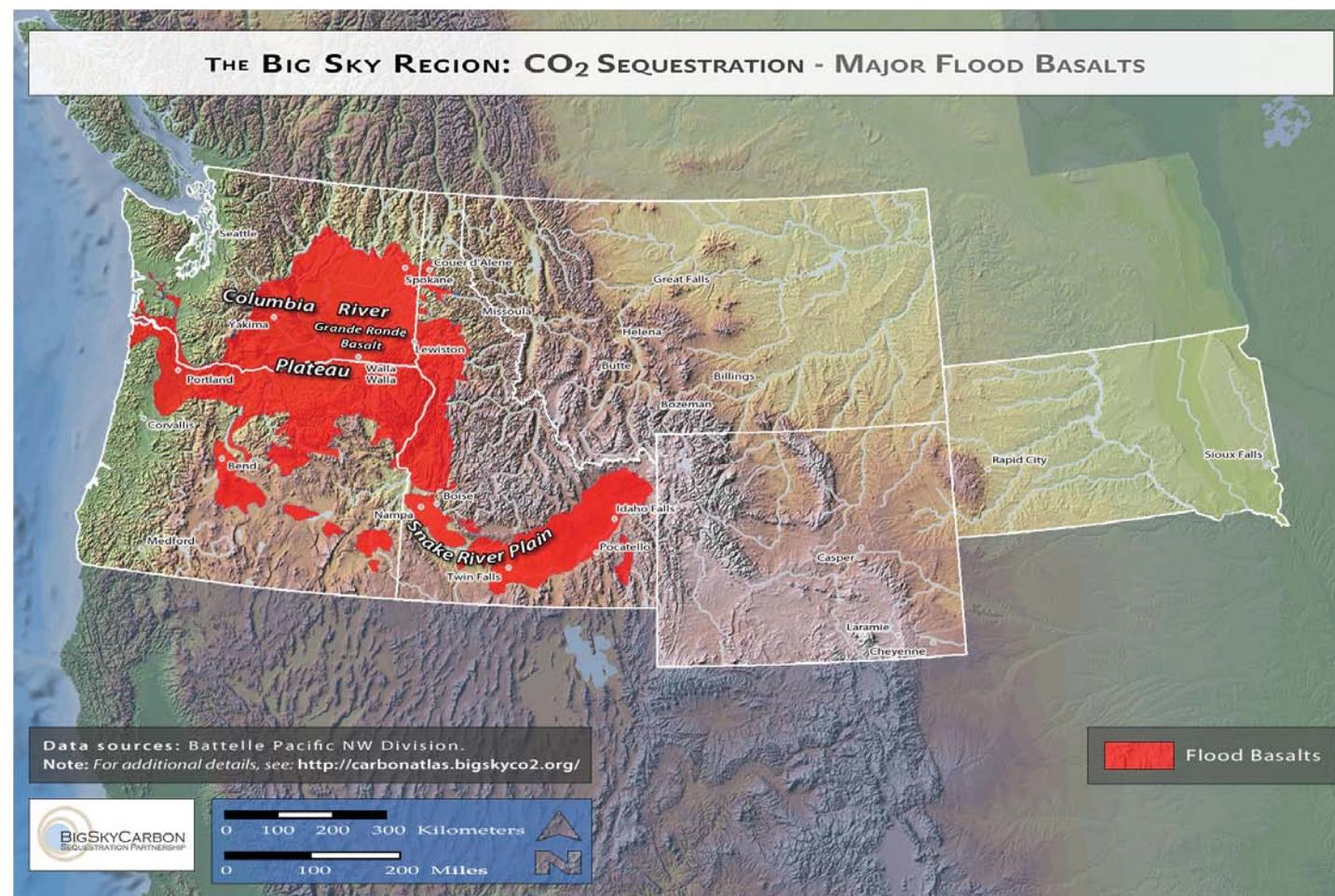
Many of these formations consist of reactive carbonate rocks that react with CO<sub>2</sub> to form calcium carbonate through various chemical and mineralization processes. The CO<sub>2</sub> is thereby converted to compounds that in effect, becomes part of the rock in the host formation. BSCSP is conducting work in the Lost Soldier oil and gas field in Wyoming to evaluate this process. The Lost Soldier field produces oil and gas from a reactive carbonate reservoir that has been undergoing CO<sub>2</sub> EOR for more than twenty years, facilitating the study of the consequences of long-term exposure of carbonate rocks to CO<sub>2</sub>-rich fluids. Specifically, the BSCSP will be extracting cores from the formations that have been exposed to CO<sub>2</sub> over this period and determining mineralization rates to construct models to apply this information to other areas for future sequestration efforts. Rather than evaluating CO<sub>2</sub> EOR in this effort, BSCSP will determine the rate and extent of mineralization that occurs when reactive carbonate formations are injected with CO<sub>2</sub>.



## BSCSP Major Flood Basalts

Mafic volcanic (basalt) formations are a distinguishing feature of the region's geology. For example, the region's Columbia River Basalt Group covers approximately 164,000 km<sup>2</sup> (63,300 mi<sup>2</sup>). Basalt formations offer significant long-term storage potential in the region, with conservative estimates of CO<sub>2</sub> storage capacity in the range of 33–134 billion metric tons (36–148 billion tons). Large basalt formations are globally distributed, with estimates that the 5 largest basalt provinces could sequester 10,000 years of world CO<sub>2</sub> emissions. Basalt formations have a number of characteristics favorable for storage of CO<sub>2</sub> including

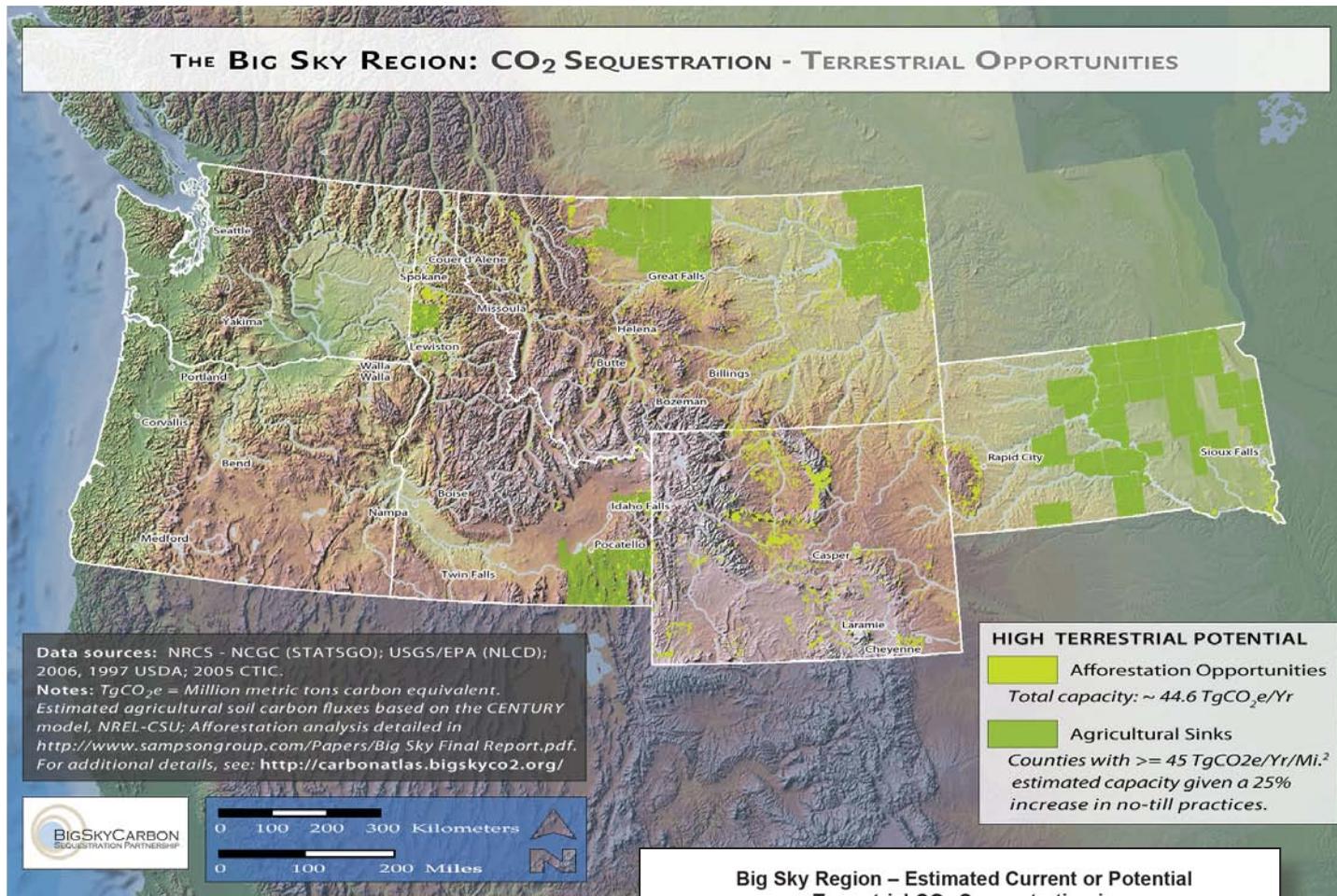
- Chemical makeup favorable for mineralization reactions
- Economic opportunity costs of using basalts are minimal
- Conducive mineralogy for sequestration
- Rapid conversion of CO<sub>2</sub> to carbonate
- High porosity and permeability



Basalt core samples



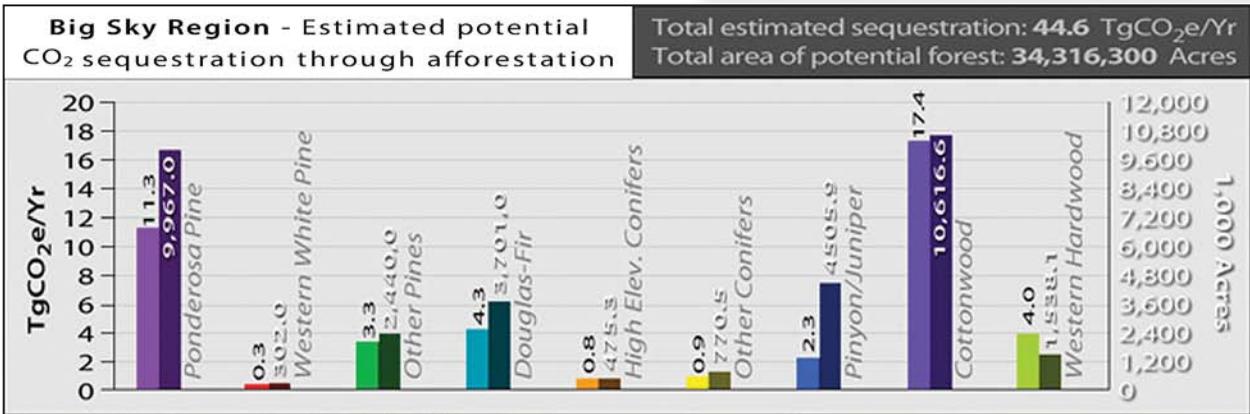
Magnified view of basalt core sample



**Big Sky Region – Estimated Current or Potential Terrestrial CO<sub>2</sub> Sequestration in Metric Tons Carbon Equivalent (MTCE)**

Agricultural:	Scenario 1	6691344
	Scenario 2	7572104
	Scenario 3	7062243
Afforestation Opportunities		44600000

Agricultural Scenarios: (1) Continuation of existing land use practices on currently associated areas; (2) 25% increase in area under no-till practices, at expense of areas under conventional tillage; (3) 25% increase in area under Conservation Reserve Program, at expense of areas under conventional tillage.



## BSCSP Terrestrial Opportunities

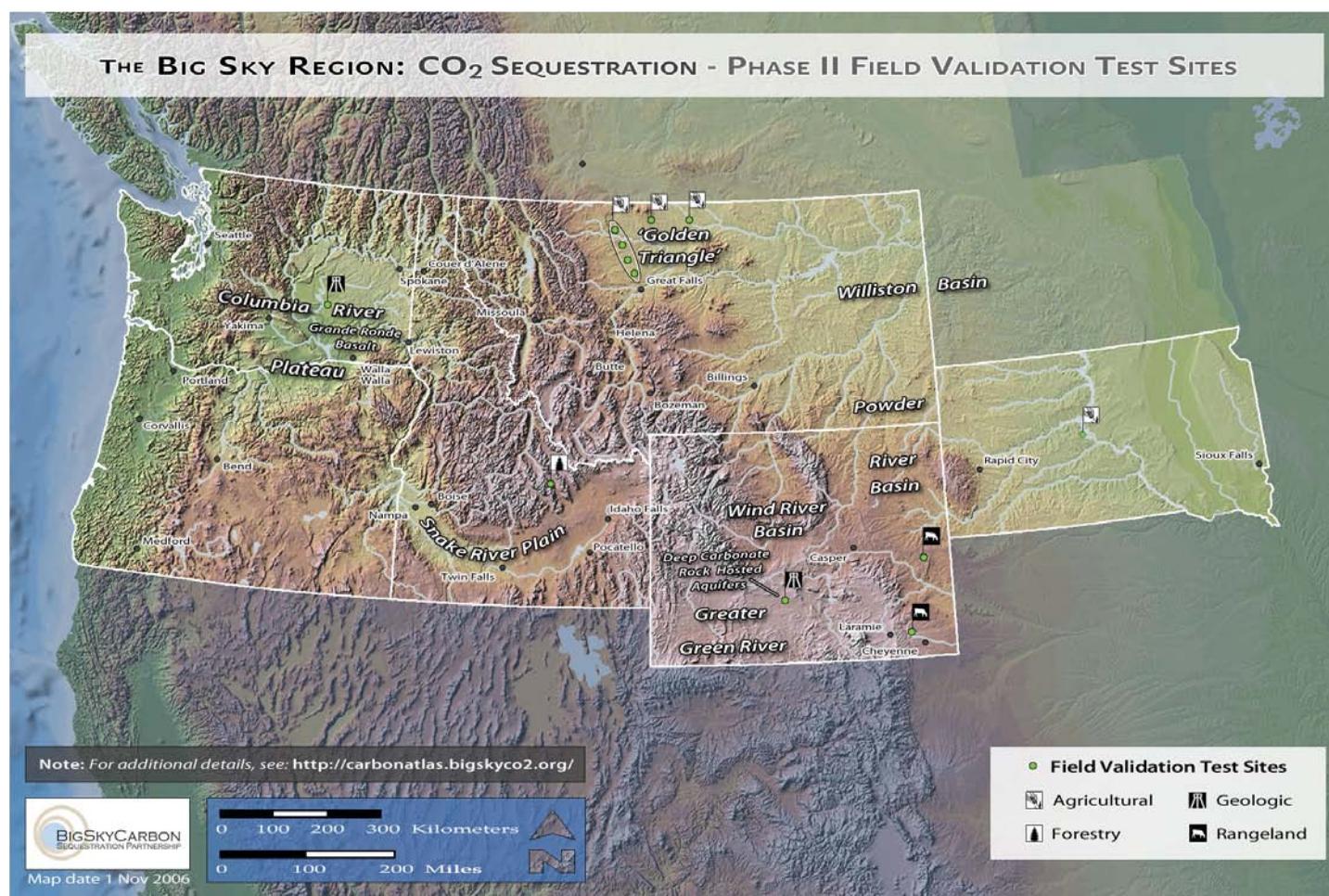
The BSCSP Region has extensive land area with land uses that provide tremendous potential for greenhouse gas (GHG) offsets through terrestrial carbon sequestration in forests, rangelands, and agricultural croplands. The Partnership has developed a market-based approach to carbon storage and verification protocols; established terrestrial pilots in cropland, forestland, and rangeland; designed carbon portfolios in conjunction with industry, tribal members, and landowners; and conducted 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 via 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 at the South Dakota School of Mines and Technology [SDSMT]).

To date, the Chicago Climate Exchange (CCX) has accepted 5,388 CO<sub>2</sub>-eq metric tons (5,939 CO<sub>2</sub>-eq tons) of forestry-based carbon credits in the pilot tribal portfolio. The projects are now undergoing third-party verification in preparation for listing on the CCX. An additional 2,000 CO<sub>2</sub>-eq metric tons (2,200 CO<sub>2</sub>-eq tons) is now under development with the Navajo nation. For the private/state lands portfolio, NCOC has obtained listing agreements for 19 cropland sequestration projects in north-central Montana with a total of 7,587 CO<sub>2</sub>-eq metric tons (8,363 CO<sub>2</sub>-eq tons).

## BSCSP Field Tests

The BSCSP plans to conduct two geologic field tests in prominent geological formations located throughout the Region (basalt formations and sedimentary rock hosted saline formations) and a preliminary study related to a potential, future enhanced coal bed sequestration field test. The BSCSP's primary geologic effort is to demonstrate carbon storage in basalt rock formations. This field test will assess the mineralogical, geochemical, and hydrologic impact of injected CO<sub>2</sub> within a basalt formation, and it will incorporate site monitoring and verification activities. Core samples will be obtained to verify laboratory and computer simulation studies showing rapid onset of carbonate mineralization in basalts.



In a secondary effort, the BSCSP is conducting a Reactive Carbonate Reservoir Assessment examining long-term CO<sub>2</sub> mineralization rates in carbonate rocks in conjunction with ongoing, long-term EOR operations at the Lost Soldier and Wertz oil fields in south-central Wyoming. The assessment will focus on the consequences of long-term exposure of carbonate rocks to CO<sub>2</sub> rich fluids using pre-and post-injection core comparisons.

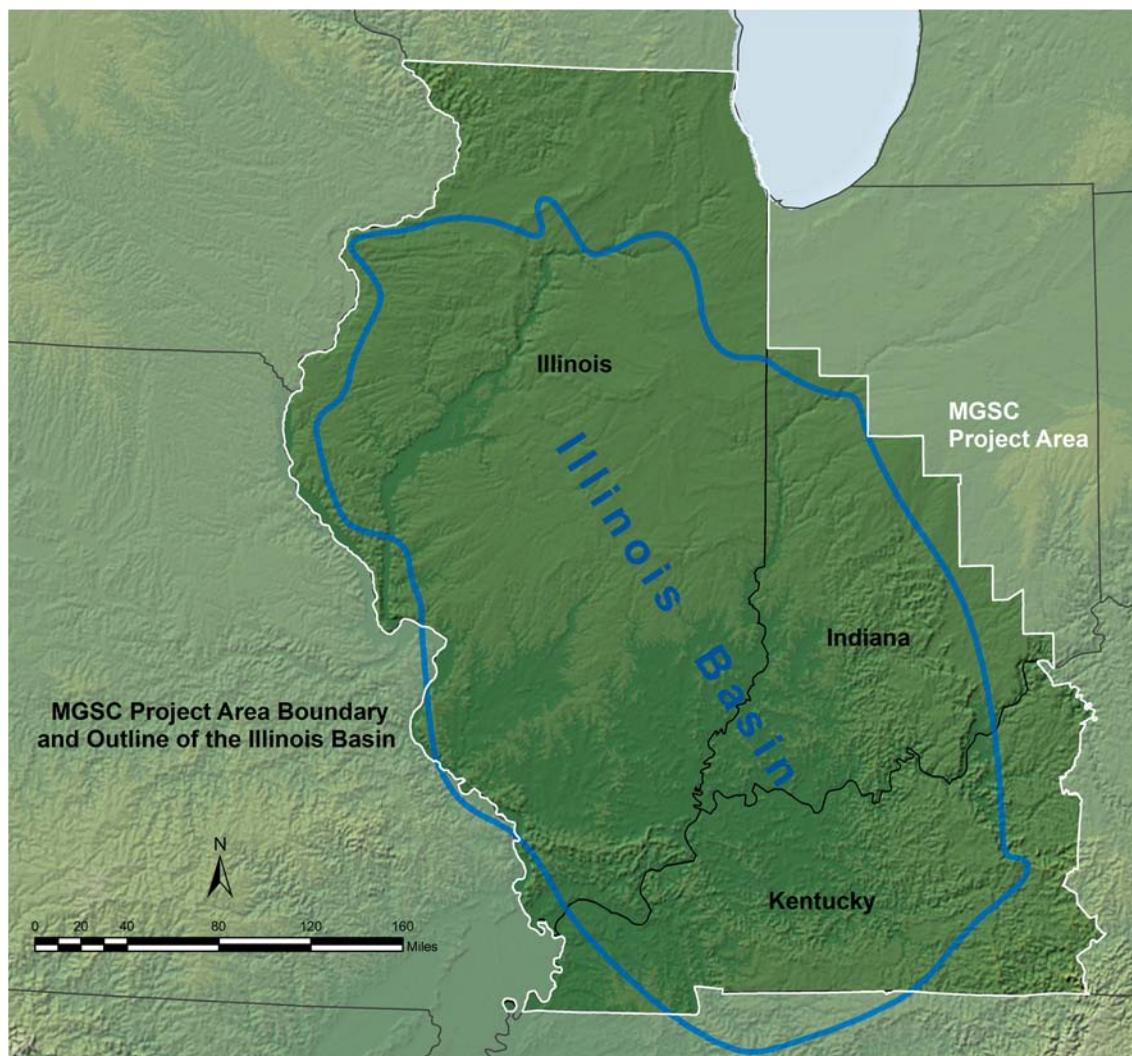
Finally, a limited amount of effort is being directed toward technical and economic issues associated with injecting a pure CO<sub>2</sub> stream into a coal seam and coal swelling effects on permeability changes. Work to date has focused on the design study that includes a technical evaluation to determine the advantages and disadvantages of injecting the flue gas versus a separated, relatively pure CO<sub>2</sub> gas stream.

The BSCSP will also determine each test site's operational needs, permitting, regulatory and monitoring requirements, and quantify economic offset opportunities such as EOR and CBM production.

Several terrestrial field tests are being performed. Cropland field tests are being conducted in the "golden triangle" region of north central Montana to (1) quantify and determine cropland management practices that optimize carbon sequestration and (2) develop MM&V protocols to evaluate carbon sequestration for enrolled farms. Rangeland field tests are being conducted to determine the effects of (1) grazing intensity and seasonality of grazing on native northern mixed-grass prairie near Cheyenne, Wyoming and (2) improvement practices on degraded northern mixed-grass prairie near Lusk, Wyoming. A field test is also planned to quantify sequestration potential in forests through understanding the effects of forest management on different carbon pools in forests.

# Midwest Geological Sequestration Consortium

The Midwest Geological Sequestration Consortium (MGSC) is a consortium of the geologic 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 covers all of Illinois, southern Indiana, and western Kentucky.



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

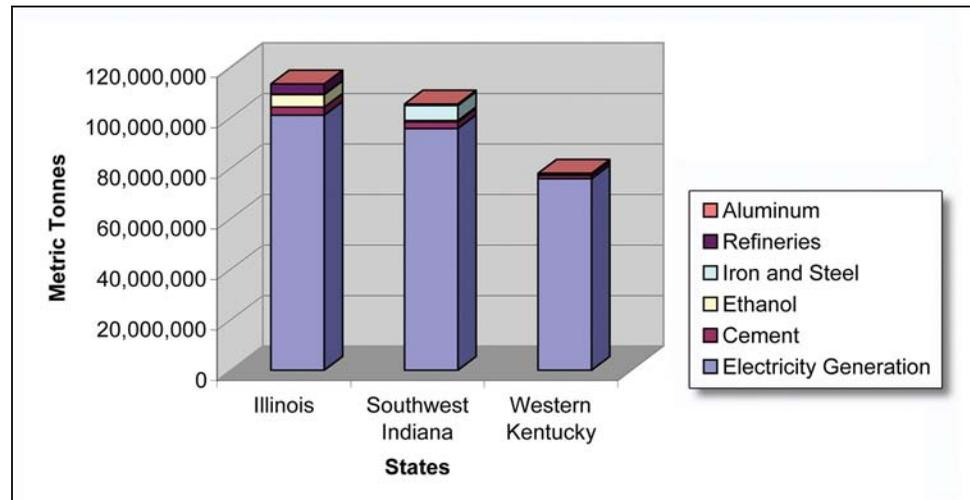
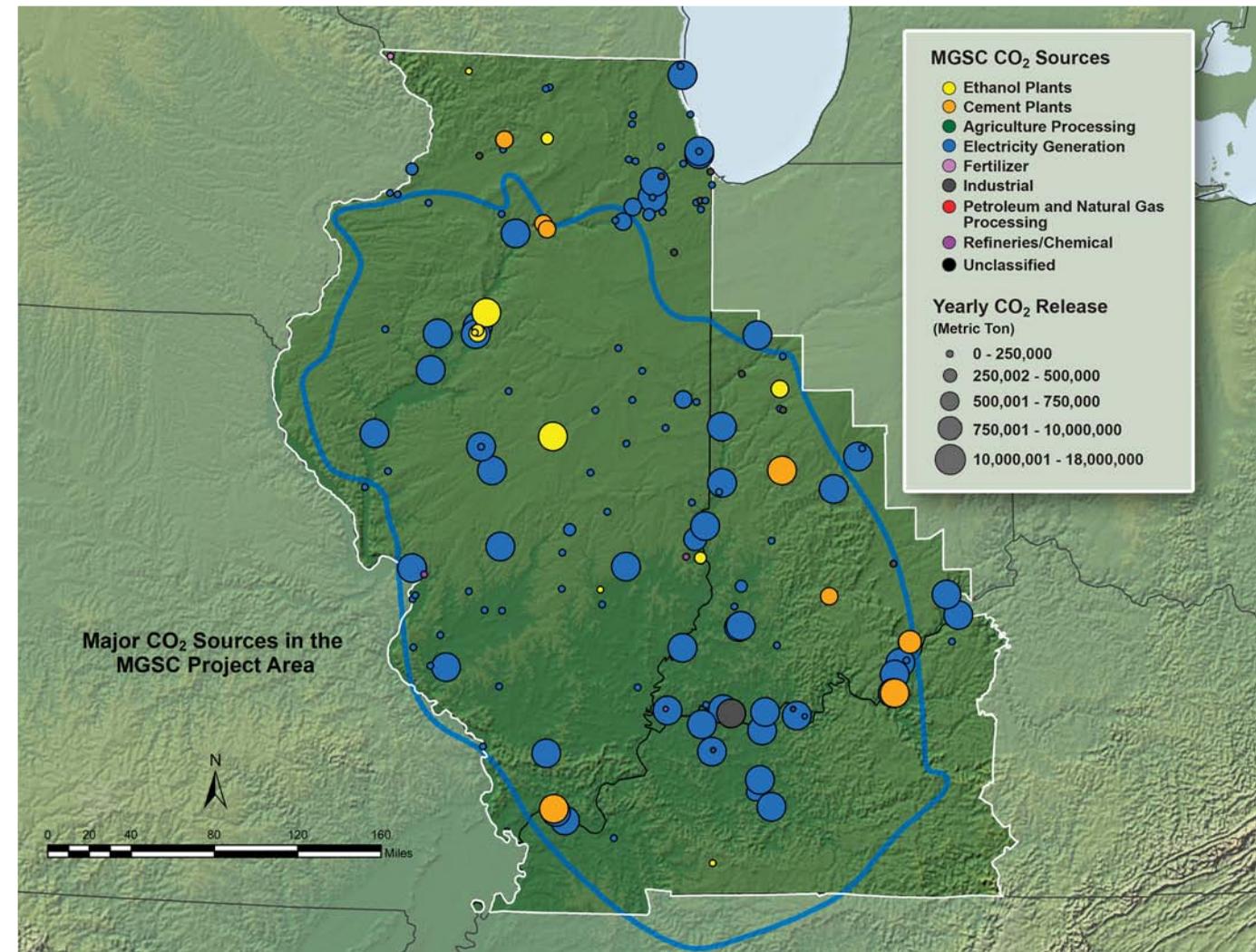
The Illinois Basin is geologically unique because all three potential geologic storage opportunities exist in close proximity to substantial CO<sub>2</sub> sources and in some cases may be accessed from one site.



Typical central Illinois Basin landscape.

## MGSC Sources

The Illinois Basin region has annual emissions exceeding 296 million metric tons (326 million tons) of CO<sub>2</sub> (>80 million metric tons [88 million tons] carbon equivalent) from fixed sources, primarily from 126 mostly coal-fired, electric generation facilities which emit >10,000 metric tons (11,000 tons), 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<sub>2</sub> emissions; the 13 largest plants emit >50 percent of total CO<sub>2</sub> emissions; and the 30 largest plants emit >80 percent of total CO<sub>2</sub> emissions. The Illinois Basin contributes about 11.4 percent of the total U.S. CO<sub>2</sub> emissions from electric power generation plants. Coal is the dominant fossil fuel for electric power plants and contributes 98 percent of the Illinois Basin CO<sub>2</sub> emissions from fixed sources. CO<sub>2</sub> emissions from manufacturing industries in the Illinois Basin vary from industry to industry.



Illinois Basin (MGSC) CO <sub>2</sub> Emissions (metric tons), by State and CO <sub>2</sub> Source Type				
Source Type	Illinois Basin Annual CO <sub>2</sub> Emissions			
	Illinois	Southwest Indiana	Western Kentucky	TOTAL
Electricity Generation	100,911,055	95,688,706	75,786,443	272,386,203
Cement	3,255,000	2,565,000	1,256,000	7,076,000
Ethanol	4,933,541	556,100	199,454	5,689,095
Iron and Steel	139,361	5,967,475	0	6,106,836
Refineries	4,109,702	94,676	0	4,204,378
Aluminum	0	475,860	677,600	1,153,460

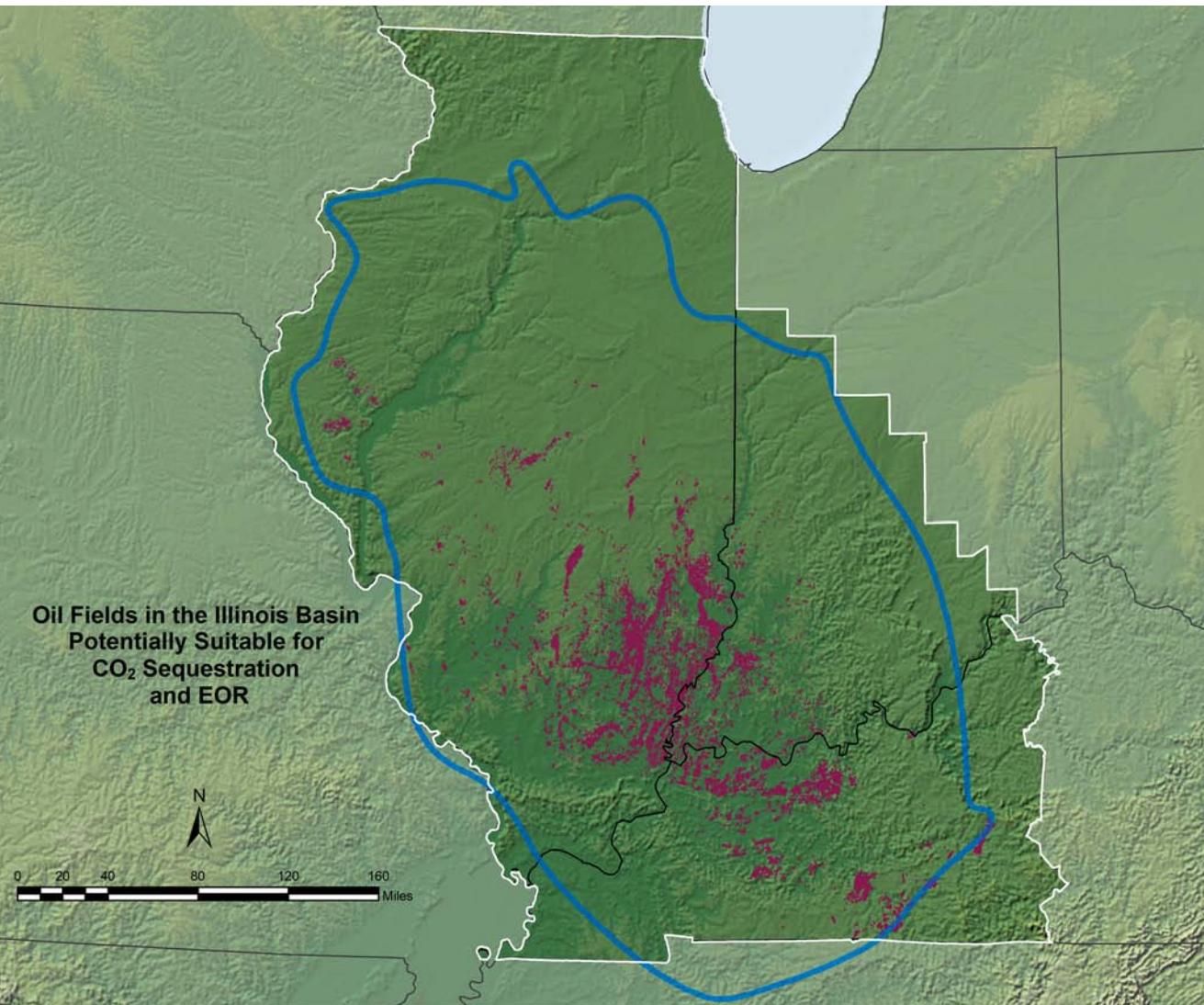


The Illinois Basin hosts significant oil refining capacity.

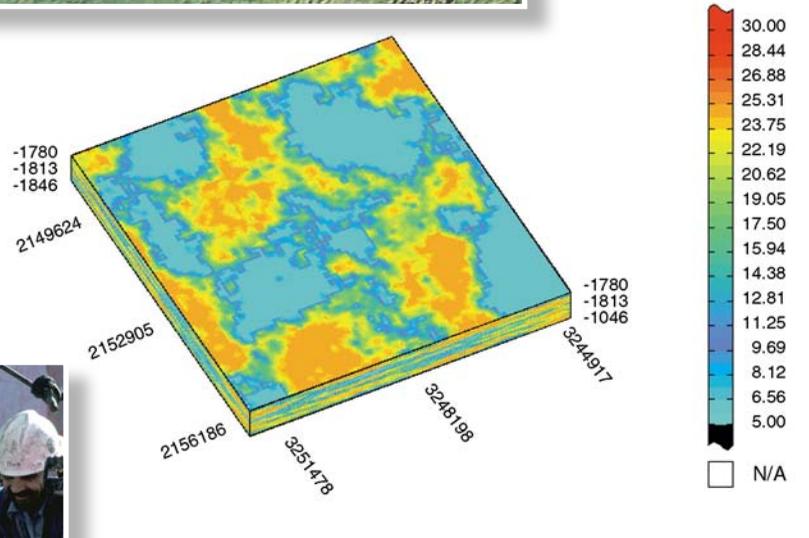
## MGSC: Illinois Basin Oil and Gas Reservoirs

Because of the established effectiveness of CO<sub>2</sub> 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 a new understanding of the OOIP in the Basin, the CO<sub>2</sub> stored volume, the assessed EOR resource, the geographical distribution of EOR potential, and the type of recovery mechanism (miscible vs. immiscible). The resource target for EOR is 137–207 million cubic meters (m<sup>3</sup>)—860–1,300 million barrels (bbls)—recoverable with consequent sequestered volume of 140–440 million metric tons (154–485 million tons) of CO<sub>2</sub>.

With cumulative oil production for the Basin of about 0.67 billion m<sup>3</sup> (4.2 billion bbls), nearly 1.5 billion m<sup>3</sup> (10 billion bbls) of resources remain, primarily as unrecovered resources in known fields. To assess the recovery potential of a part of this resource and the concurrent stored CO<sub>2</sub> volumes, reservoir modeling and compositional reservoir simulation were carried out. Parts of nine fields were used to create generic geologic models for the most prolific reservoirs in the Basin, the Aux Vases and Cypress Sandstones and the Ste. 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 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<sub>2</sub> injection.



Well drilling in the Illinois Basin.



Model showing porosity in the Aux Vases Sandstone.

Potential CO <sub>2</sub> Capacity	Estimated EOR*
140–440 million metric tons (154–485 million tons)	137 million–200 million m <sup>3</sup> (860 million–1,300 million barrels)

\* The EOR volume was estimated based on a series of oil recovery factors for specific geologic units and miscibility type 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 Powder River Basin, and Illinois coal production has declined by half since 1990. The opportunity to sequester CO<sub>2</sub> in coals currently considered to be unmineable is based on both technical and economic considerations and could be supported by production of coalbed methane (CH<sub>4</sub>) displaced from these coals.

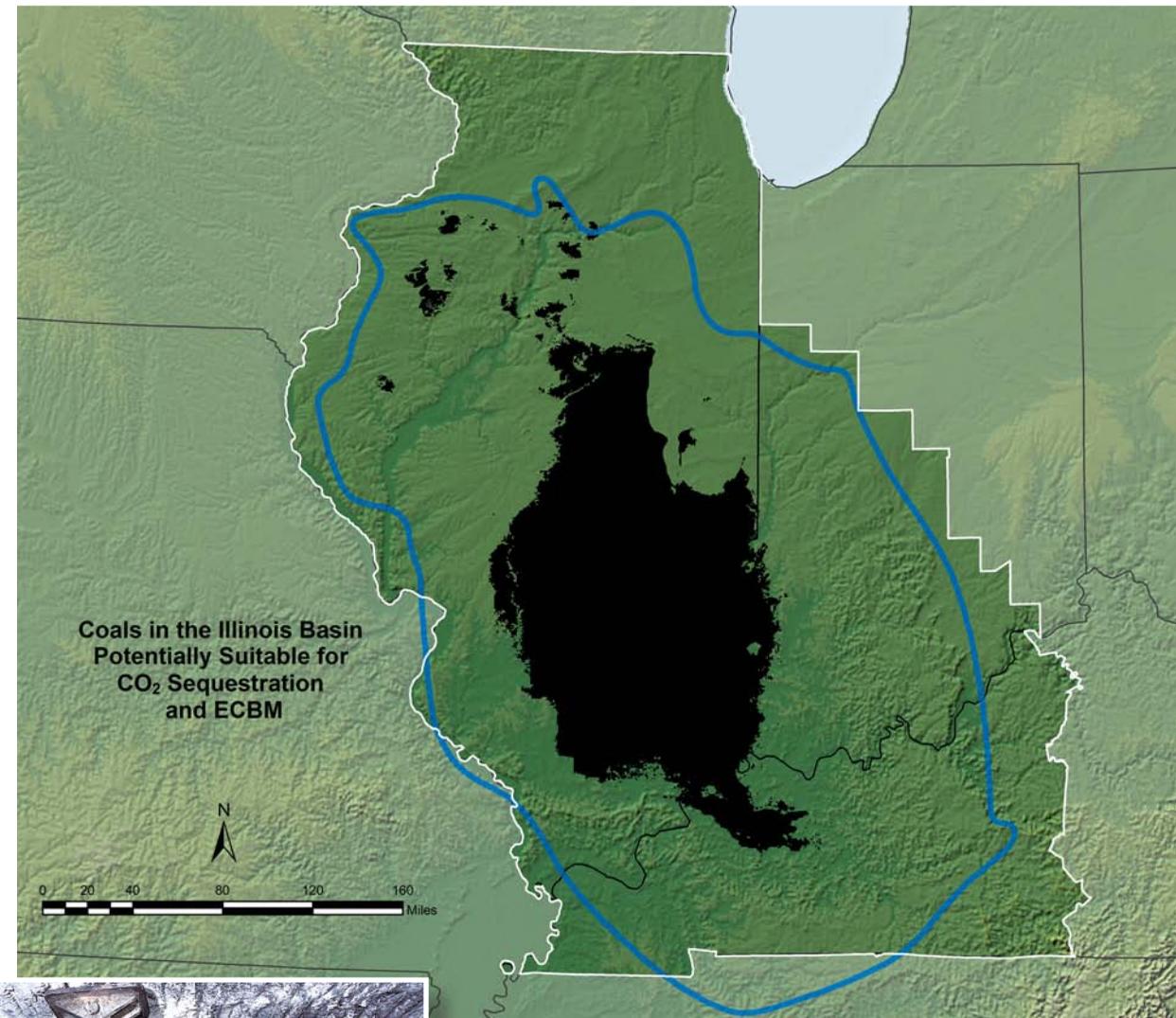
With respect to defining unmineable coal, no consideration is given to coals at depths <152 m (<500 ft). Coals from 152–305 m (500–1,000 ft) in depth and from 0.48–1.1 m (1.5–3.5 ft) thickness are considered sequestration targets. A seam <1.1 m (<3.5 ft) in thickness is currently not mineable with existing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

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 3.12–4.68 m<sup>3</sup>/metric ton (100–150 standard cubic feet [scf]/ton) for the better samples; CO<sub>2</sub> adsorption capacity can range from 14.1–21.9 m<sup>3</sup>/metric ton (450–700 scf/ton) at 2,068 kilopascals (300 psi).

**Potential CO<sub>2</sub> Capacity**  
**2.3–3.3 billion metric tons**  
**(2.5–3.6 billion tons)**

**Estimated ECBM\***  
**0.08–0.31 trillion m<sup>3</sup>**  
**(3.0–10.9 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.



Coal mining in the Illinois Basin.

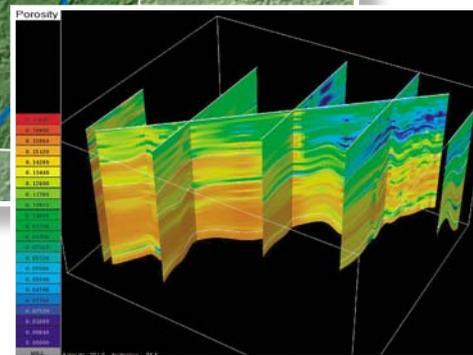
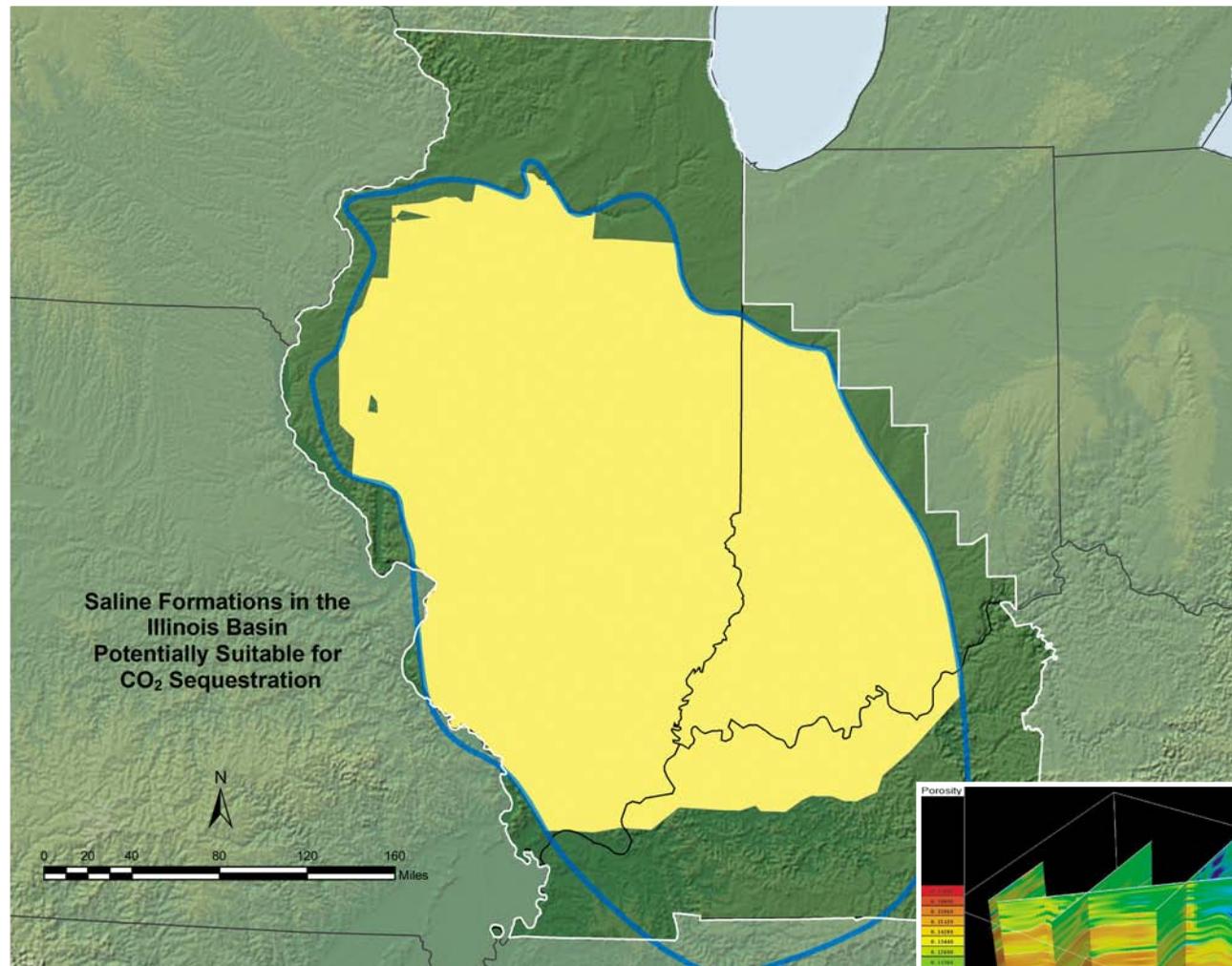


## MGSC: Illinois Basin Deep Saline Formations

Two major saltwater-filled, or saline, reservoirs in the Illinois Basin were studied for CO<sub>2</sub> storage potential: the Ordovician St. Peter Sandstone and the Cambrian Mt. Simon 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 include several hundred feet of dense limestone and dolostone overlain by 45.7–76.2 m (150–250 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. The major seal for the Mt. Simon is the Eau Claire Formation which averages 102–305 m (400–1,000 ft) in thickness. The strata overlying the Eau Claire Strata contain impermeable limestone, dolomite, and shale intervals. The depth of the Mt. Simon ranges from approximately 610–4,267 m (approx. 2,000–14,000 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 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<sub>2</sub> reservoir facies are either very deep or are absent in the paleotopography.

Depths less than 762 m (2,500 ft) for the St. Peter and Mt. Simon Sandstones were not considered as sequestration targets due to anticipated lower salinity and potentially potable water resources in these areas.



Model showing potential post-injection CO<sub>2</sub> migration in the Mt. Simon Sandstone.

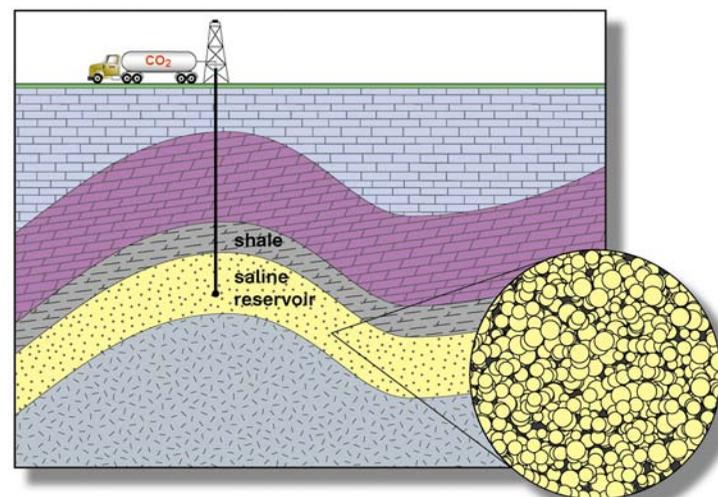
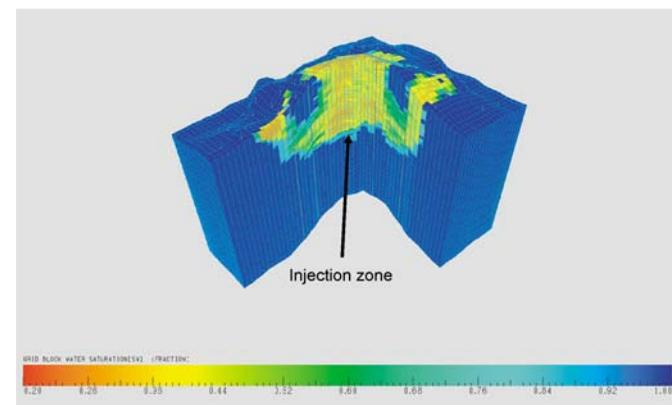


Figure showing CO<sub>2</sub> injection into porous sandstone.



Model showing porosity in the Mt. Simon Sandstone.

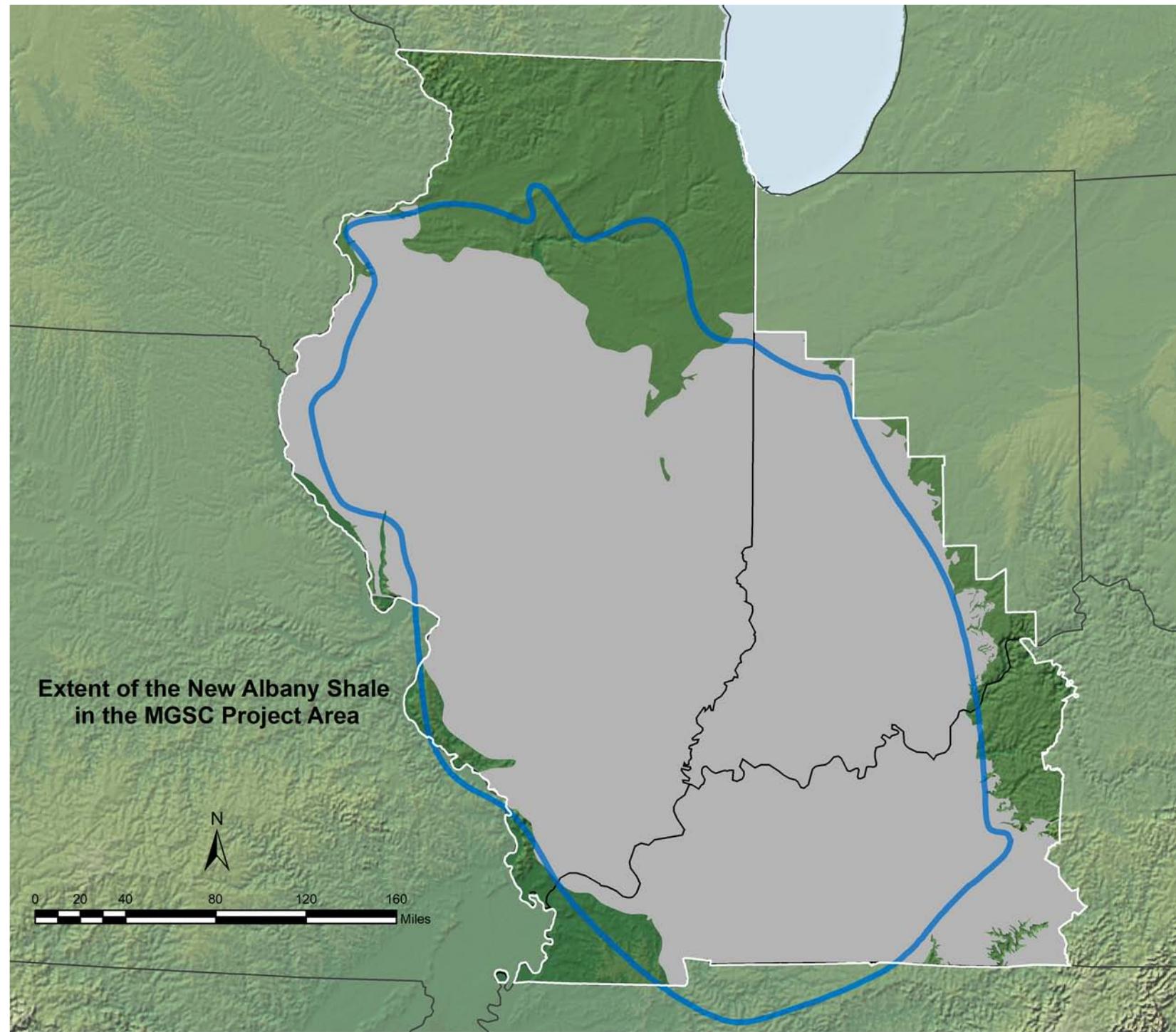
Reservoir	Potential CO <sub>2</sub> Capacity
St. Peter Sandstone	1.6–6.4 billion metric tons (1.8–7.0 billion tons)
Mt. Simon Sandstone	27–109 billion metric tons (30–120 billion tons)
<b>Total</b>	<b>29–115 billion metric tons (32–127 billion tons)</b>

## MGSC: Illinois Basin Organic-Rich Shales

Organic-rich shales in the Illinois Basin will be assessed from two perspectives. The Devonian New Albany Shale in the Illinois Basin is commercially productive of natural gas in the same manner as deep coal seams. It is stratigraphically equivalent to the Antrim Shale in the Michigan Basin and the Ohio Shale in the Appalachian Basin, a shale gas play that currently supports over 25,000 producing wells in those basins. The New Albany is producing gas in Indiana and Kentucky, and samples from these localities are currently being tested for their CO<sub>2</sub> adsorption capacity. Organic carbon content of the shale is directly related to the CO<sub>2</sub> adsorption capacity. Injection of CO<sub>2</sub> into the organic shales may result in adsorption of CO<sub>2</sub> and possibly the enhanced production of CH<sub>4</sub>, just as in coal beds. Adsorption isotherm data and geophysical logs will be used to estimate and identify areas of the Basin with sequestration potential in the shale. Because of its CO<sub>2</sub> adsorption potential, the New Albany may also act as a secondary seal for sequestration in any deeper saline reservoirs, like the St. Peter and Mt. Simon Sandstones.



Regional Shale Outcrop



## MGSC: Illinois Basin Terrestrial Opportunities

A number of universities and other groups in the Illinois Basin are actively researching many terrestrial sequestration techniques. The Illinois Basin is an area rich in agricultural resources with many terrestrial sequestration opportunities currently under assessment. Approximately 33.1 percent of all grain fields in Illinois were planted using no-till methods in 2006, an increase of 3.9 percent from 2004. Long-term studies of tillage impacts on erosion, soil fertility, and organic matter storage are being conducted at the University of Illinois. Remote sensing techniques are being employed to research soybean uptake of CO<sub>2</sub>. Ongoing research is being conducted by the Illinois State Geologic Survey on wetlands restoration and mitigation throughout the Illinois Basin.



*Aerial view showing no-till farming in the Illinois Basin.*



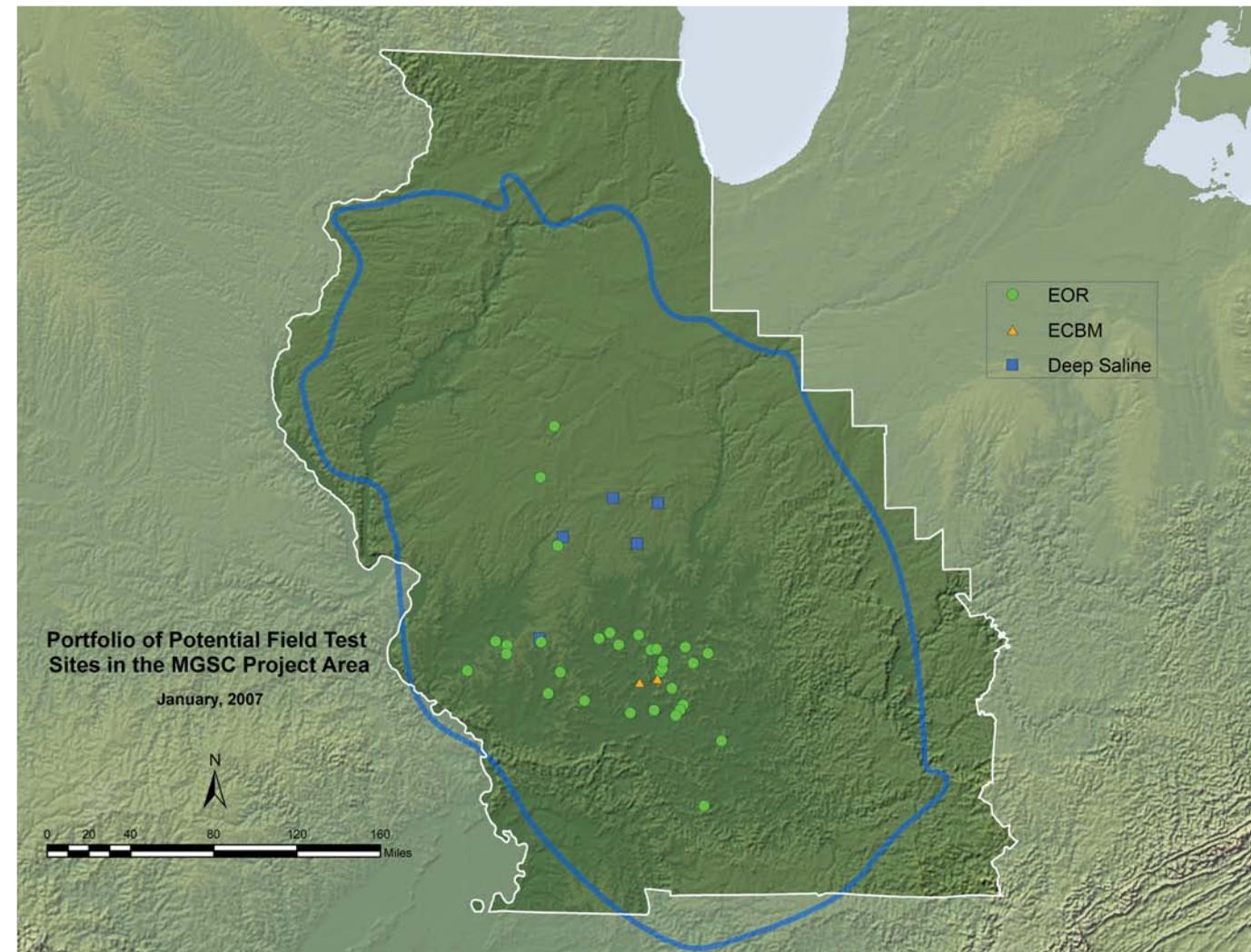
*Scientists testing response in soybeans from CO<sub>2</sub> release.*



## MGSC 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<sub>2</sub> storage in oil reservoirs, coal seams, and deep saline water-bearing formations. Added-value benefits for oil reservoirs and coal beds are the potential for EOR and ECBM production, respectively. While the deep saline test has no enhanced production potential, it is expected to utilize the geologic formations with the largest CO<sub>2</sub> storage capacity in the test area.

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 reservoir and injecting supercritical CO<sub>2</sub>. 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 Permian Basin (West Texas) experience, which is dominated by miscible carbonate floods. As a result of initial characterization work, some 31 oil field sites, several possible ECBM sites, and five saline reservoir sites have been identified as possible test sites.



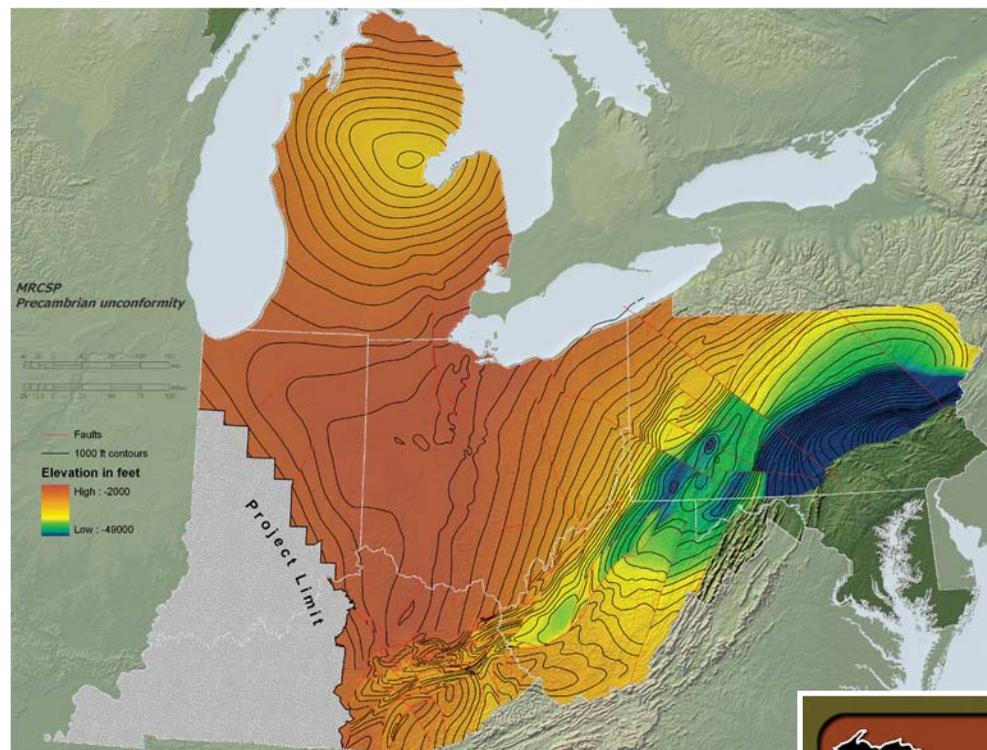
Preparing for Pilot field test at Loudon Field, Illinois.



Equipment showing skid and line heater.



# Midwest Regional Carbon Sequestration Partnership



CO<sub>2</sub> pipeline from a gas processing plant in Michigan.

The Midwest Regional Carbon Sequestration Partnership (MRCSP) was formed to assess the regional technical potential, economic viability, and public acceptability of carbon sequestration. The MRCSP Region consists of seven contiguous states: Indiana, Kentucky, Maryland, Michigan, Ohio, Pennsylvania, and West Virginia. The MRCSP includes more than 30 organizations from the research community, energy industry, universities, non-government, and government organizations. The Region has a diverse range of CO<sub>2</sub> sources and many opportunities for geologic and terrestrial sequestration.

Potential locations for geologic sequestration in the Region include deep rock formations associated with broad sedimentary basins. Initial assessments show the presence of numerous geologic units in the area and delineated the most promising geologic reservoirs for CO<sub>2</sub> sequestration. The geologic surveys from seven states worked together to complete the geologic assessment. In total, the geologic assessment resulted in 30 original depth and thickness maps, 9 regional thematic maps, and 14 capacity maps, using data from more than 85,000 control-points stored in a state-of-the-art geographic information system available for interactive use on the team's website ([www.mrcsp.org](http://www.mrcsp.org)). These maps and data indicate that deep saline formations, oil and gas reservoirs, organic shale layers, and coalbeds have a combined capacity to permanently contain hundred's of years of CO<sub>2</sub> emissions from the Region.

MRCSP 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 noneroded cropland, eroded cropland, marginal lands, mineland areas, and wetlands. The specific objectives of the research were to quantify the carbon sequestration capacity of the major land use components and to identify land use and management options to achieve maximum capacity such as improved agricultural practices, reforestation, and reclaiming mineland.

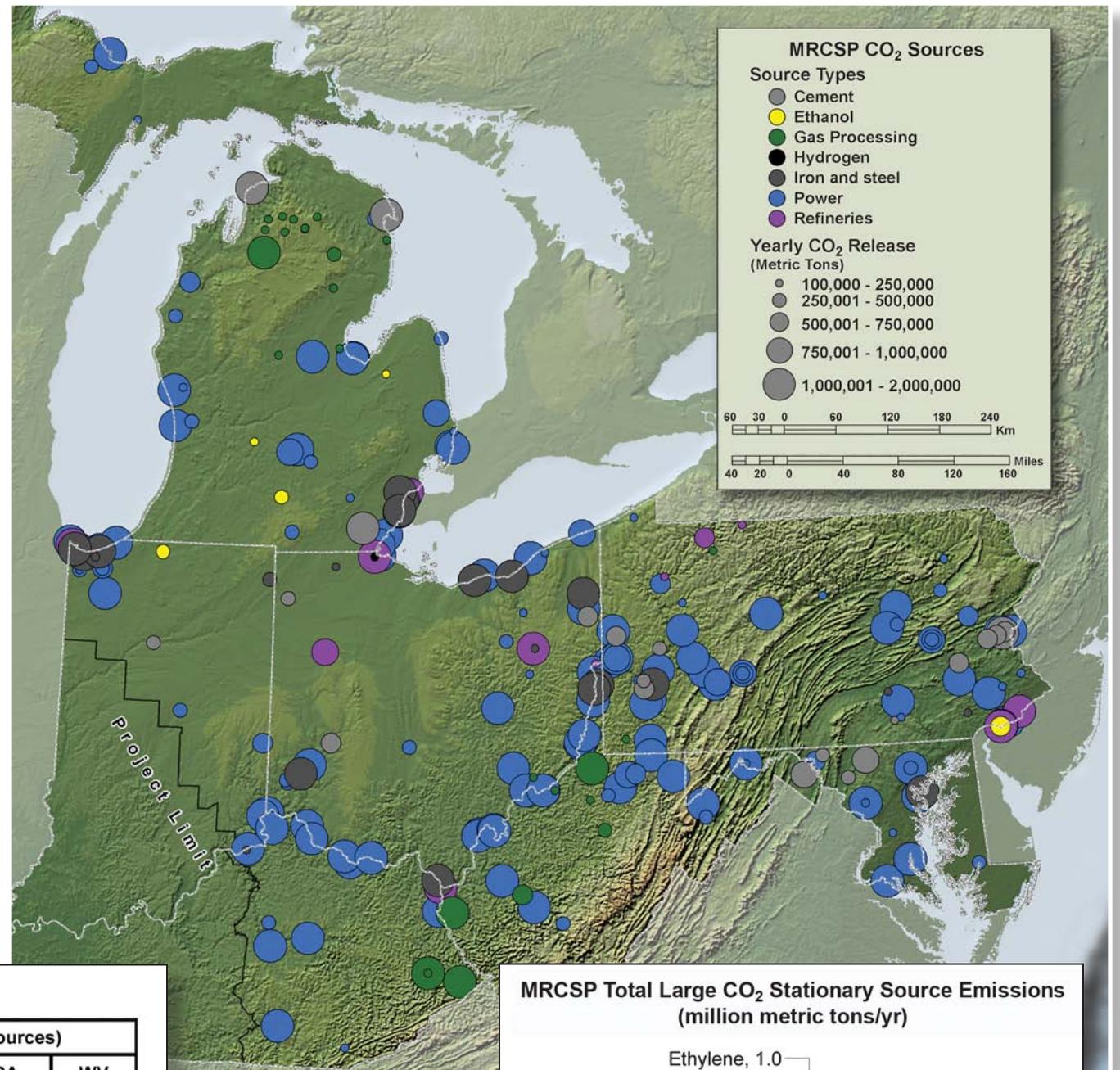
## A Snapshot of the MRCSP Region

The MRCSP Region includes

- 7 states: Indiana, Kentucky, Maryland, Michigan, Ohio, Pennsylvania, and West Virginia
- Population: 50.8 million (1 in 6 Americans)
- Gross Regional Product: \$1,534 billion (1/6 U.S. economy)
- 21.5 percent of all electricity generated in the U.S.
- 77 percent of electricity generated in the Region is generated by coal
- 12 percent of nation's total CO<sub>2</sub> emissions

## CO<sub>2</sub> Sources in the MRCSP Region

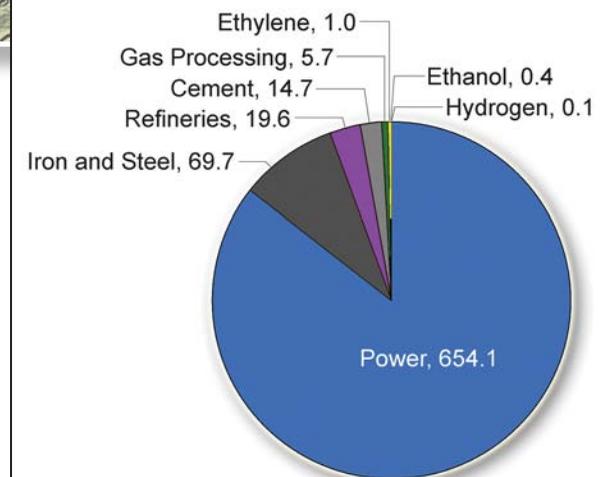
Due to its large and diverse economy, the MRCSP Region includes a large variety of GHG sources. While distributed sources such as agriculture, transportation, and heating account for 34 percent of CO<sub>2</sub> emissions in the MRCSP Region, 66 percent of CO<sub>2</sub> emissions are linked to large stationary sources. More than 750 million metric tons (827 million tons) of CO<sub>2</sub> is 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, 85 percent of CO<sub>2</sub> stationary source emissions are from electrical power plants.



CO<sub>2</sub> Emissions from Large Point Sources in MRCSP Region

Category	Large CO <sub>2</sub> Point Source Emissions in million metric tons CO <sub>2</sub> /year (# sources)								
	MRCSP	MRCSP%	IN	KY	MD	MI	OH	PA	WV
Power	654.1 (207)	85.5%	124 (33)	93 (22)	32 (15)	76 (33)	127 (31)	116 (55)	86 (18)
Iron and Steel	69.7 (23)	9.1%	26.4 (7)	2.4 (2)	4.5 (1)	11.8 (3)	17.4 (7)	3.2 (2)	4.0 (1)
Refineries	19.6 (14)	2.6%	4.2 (2)	2.1 (1)	0 (0)	0.7 (1)	5.3 (4)	7.2 (5)	1.1 (1)
Cement	14.7 (23)	1.9%	2.4 (4)	0.5 (1)	1.5 (3)	3.5 (3)	1.4 (3)	4.6 (8)	0.8 (1)
Gas Processing	5.6 (9)	0.7%	0 (0)	0.4 (2)	0 (0)	1.2 (2)	0 (0)	0.1 (1)	3.9 (4)
Ethylene	1.0 (3)	0.1%	0 (0)	0.5 (2)	0 (0)	0 (0)	0 (0)	0.5 (1)	0 (0)
Ethanol	0.4 (2)	0.1%	0.3 (1)	0 (0)	0 (0)	0.1 (1)	0 (0)	0 (0)	0 (0)
Hydrogen	0.1 (1)	0.0%	0 (0)	0 (0)	0 (0)	0 (0)	0.1 (1)	0 (0)	0 (0)
<b>Total</b>	<b>765 (282)</b>	<b>100%</b>	<b>157 (47)</b>	<b>98 (30)</b>	<b>38 (19)</b>	<b>93 (43)</b>	<b>152 (46)</b>	<b>132 (72)</b>	<b>95 (25)</b>

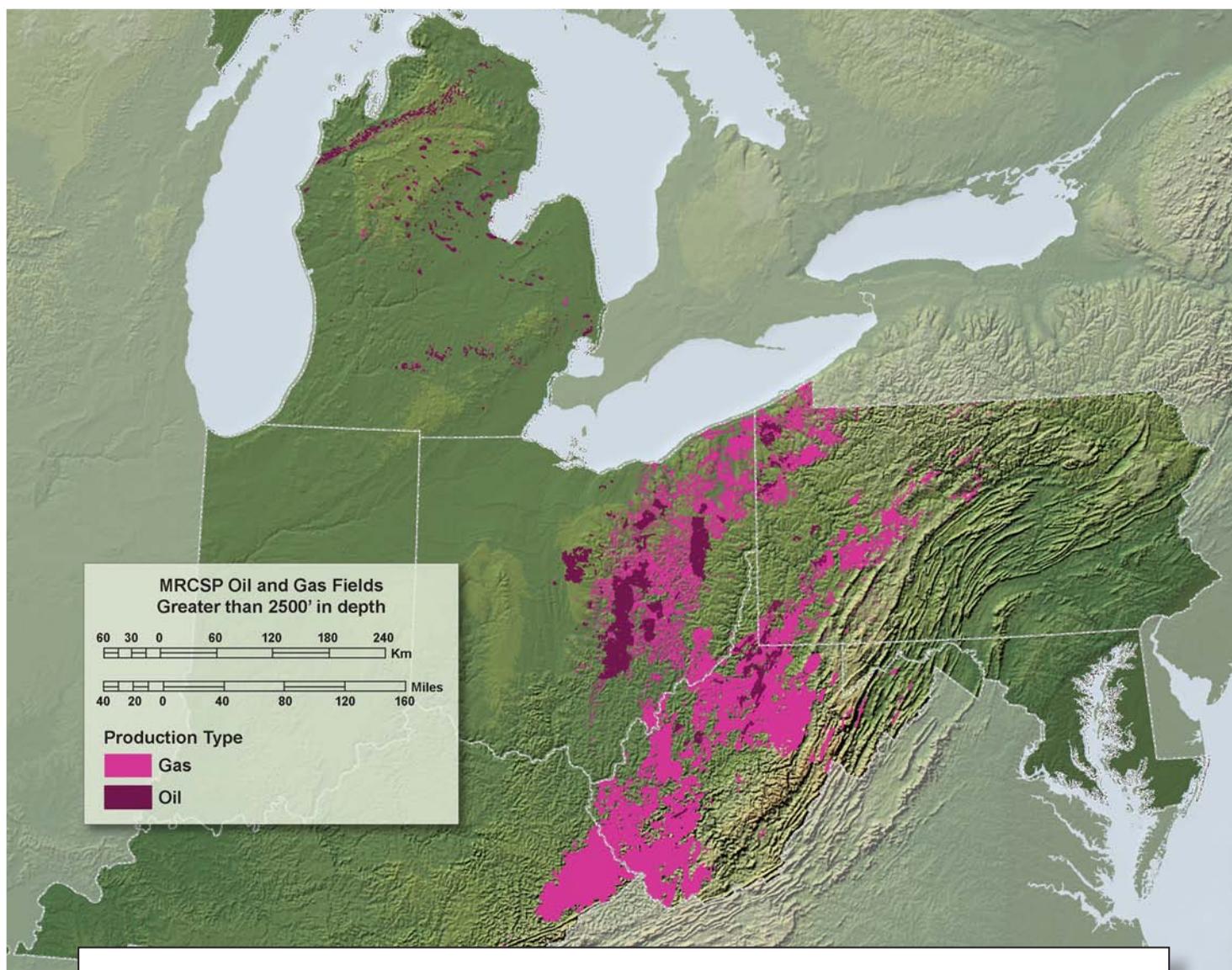
MRCSP Total Large CO<sub>2</sub> Stationary Source Emissions (million metric tons/yr)



## MRCSP Oil and Gas Reservoirs

The MRCSP Region has many opportunities for CO<sub>2</sub> sequestration in oil and gas reservoirs. Exploration for oil in the Region began in 1859 with the discovery of oil by Colonel Drake in Oil City, Pennsylvania. Since that time, the MRCSP Region has produced more than 0.8 billion m<sup>3</sup> (5 billion barrels) of oil and more than 7.9 trillion m<sup>3</sup> (50 trillion cubic feet) of natural gas. In addition, significant amounts of natural gas are stored in the Region. Such large volumes of gas storage capacity (both natural and engineered) strongly suggest that CO<sub>2</sub> gas can be successfully managed in subsurface reservoirs within the Region. 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 sequestration capacity of at least 2,500 million metric tons (2,760 million tons) of CO<sub>2</sub>. Much of this capacity 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 eastern Ohio, western Pennsylvania, western West Virginia, and eastern Kentucky. Key oil and gas rock 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 margin of the Basin and the southern margin of the Basin. Enhanced oil recovery with CO<sub>2</sub> has only been applied in a few fields in the Region. However, studies have suggested that a large amount of oil and gas remains in place in many reservoirs. Thus, potential is high for enhanced oil and gas production associated with CO<sub>2</sub> sequestration in the MRCSP Region.



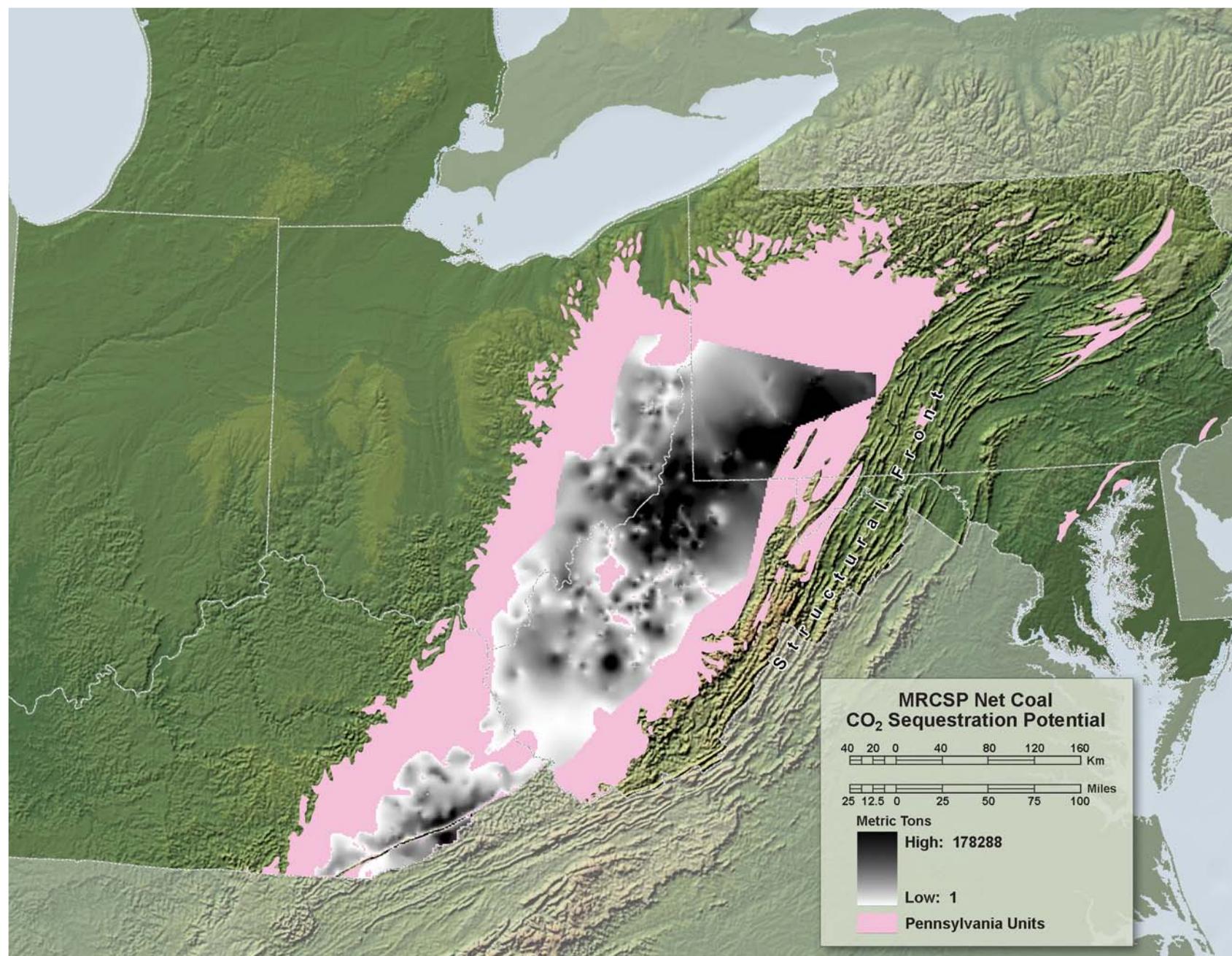
Top Ten Gas and Oil Fields in the MRCSP Region and Calculated CO<sub>2</sub> Storage Capacities

Field Name	State	Producing Formation	Average Depth (ft)	#Wells	Acres	CO <sub>2</sub> Storage Potential (million metric tons)
South Burns Chapel	WV	Oriskany-Hrbg	7,634	130	64,046	341
Elk-Poca (Sissonville)	WV	Oriskany	5,032	1,121	244,733	330
Volant	PA	Medina	6,050	353	31,451	310
Weston-Jane Lew	WV	Devonian Shale	3,179	292	56,137	258
E. Canton Consolidated – S	OH	Clinton	5,300	1,290	120,430	251
N. Ellsworth Consolidated	OH	Clinton	5,100	662	108,919	245
Baltic	OH	Rose Run	6,390	113	84,083	232
Weston	WV	Devonian Shale	4,336	553	63,714	196
Roaring Run	PA	Devonian Shale	2,600	355	21,400	176
Belington	WV	Devonian Shale	4,169	552	53,877	172

## MRCSP Unmineable Coal Beds

The MRCSP Region contains the second- (West Virginia), third- (Kentucky), fourth- (Pennsylvania) and fourteenth- (Ohio) leading coal-producing states in the nation. Bituminous coal beds are located in the Appalachian and Michigan basins and anthracite coal beds are located in Pennsylvania. Portions of these coal beds are considered “unmineable” because they are either located too deep below the ground or the coal seams are too thin to mine. Analysis of coal beds in the MRCSP Region indicate that it may be possible to sequester up to 1,000 million metric tons (1,100 million tons) of CO<sub>2</sub> in unmineable coal beds in the Appalachian Basin alone. Deep unmineable coal beds in the Appalachian basin with the highest capacity for CO<sub>2</sub> sequestration are located along the Ohio River Valley in Kentucky, Ohio, Pennsylvania, and West Virginia.

The potential exists for using CO<sub>2</sub> for ECBM recovery in coal beds in the Appalachian basin. In the past 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 also occur in the northern portion of West Virginia. Historically, CBM production took place in eastern Kentucky, and it is reported as taken place in Ohio 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<sub>2</sub> sequestration potential—and much of the existing data vital in understanding CBM systems is not publicly available.



## MRCSP Deep Saline Formations

Deep saline rock formations are, by far, the MRCSP Region's largest assets for long-term geologic CO<sub>2</sub> sequestration. Initial mapping indicates that the Region's well-defined deep saline formations could potentially sequester up to 189,000 million metric tons (208,000 million tons) of CO<sub>2</sub>. The estimated CO<sub>2</sub> storage capacity for the Region is very large compared to the present-day emissions, enough to accommodate CO<sub>2</sub> emissions from large stationary sources in the Region for hundreds of years. Saline formations in the MRCSP Region are widespread, close to many large CO<sub>2</sub> sources, and are thought to have large pore volumes available for injection use. However, storage capacity is not evenly distributed across the Region.

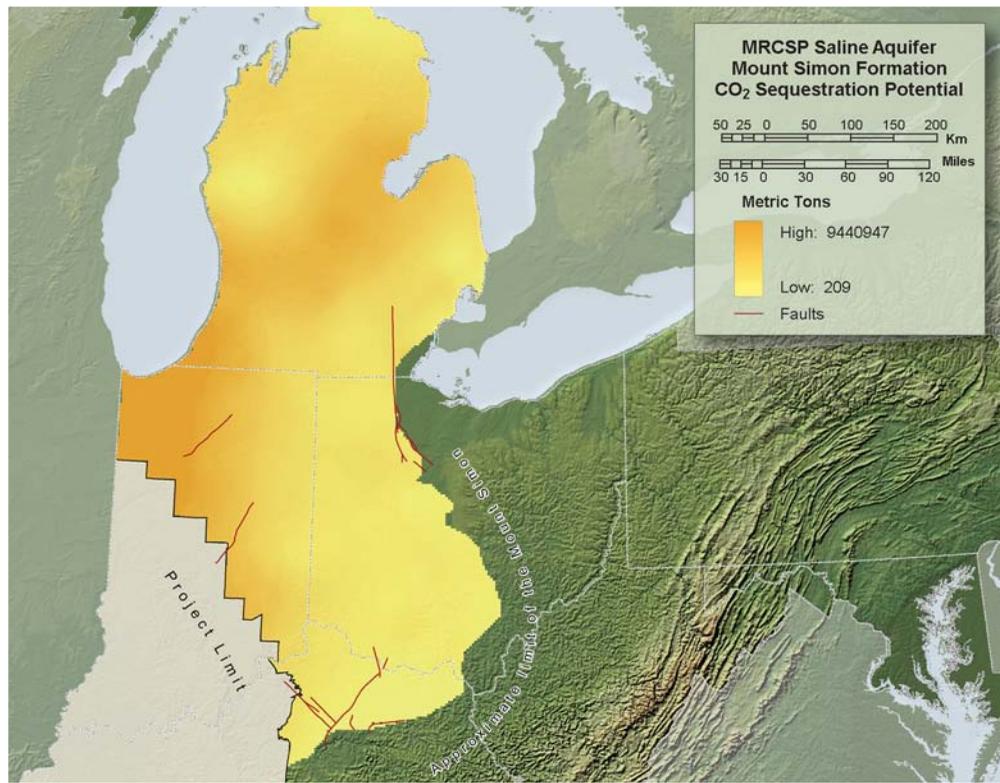
Thick sequences of sedimentary rocks are present throughout most of the MRCSP states in the form of broad basins and arches. The rocks are saturated with dense brine fluids. In addition, the Region is considered a fairly stable geologic setting. The rock formations have been correlated and mapped in 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 throughout the Region.

The storage capacity in each reservoir is largely a function of its spatial extent, thickness, and porosity. Given its presence in much of the MRCSP Region, the saline formation with the largest capacity 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. In addition to these storage options, the Region may have several other attractive options, however, due to a lack of existing exploratory wells in many areas, such as in the deepest portion of the Appalachian basin in Pennsylvania, the potential storage capacity in some areas of the MRCSP Region could not be accessed. While Michigan has the highest storage potential, all of the seven states in the MRCSP Region have the capacity to store large amounts of CO<sub>2</sub> in deep saline formations.

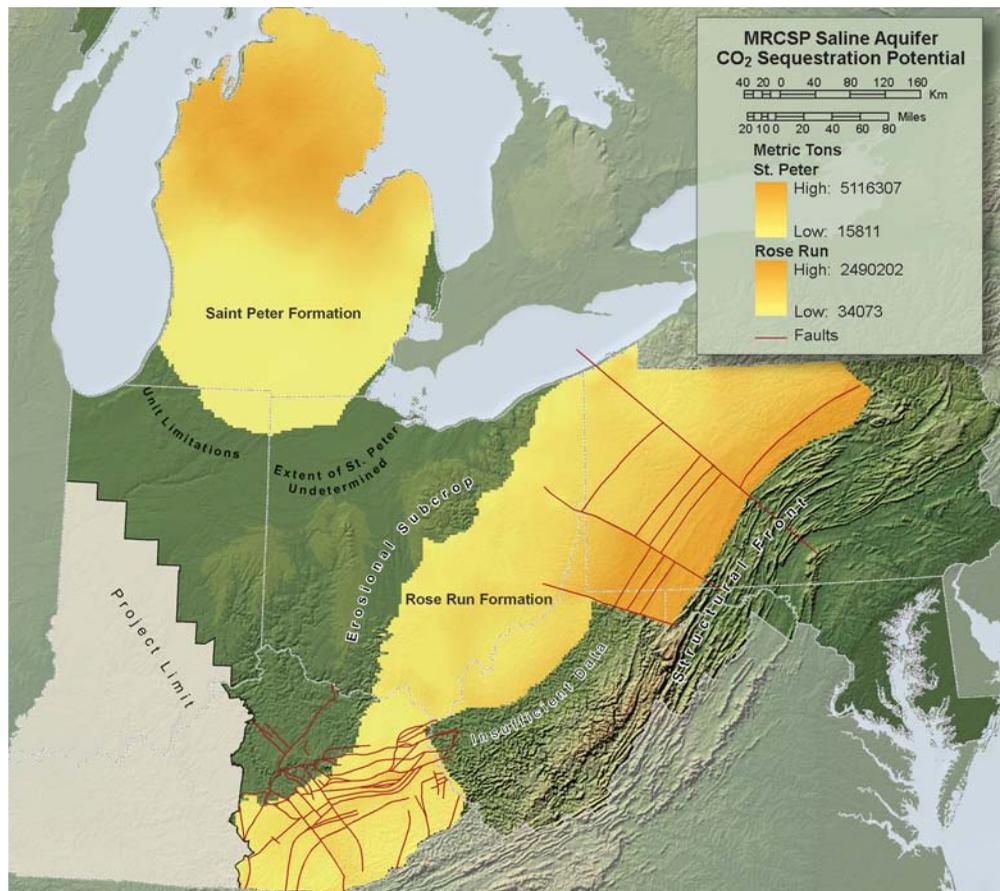
Estimated CO<sub>2</sub> Storage Potential in Major Deep Saline Formations in the MRCSP Region

Deep Saline Target	Estimated Capacity (million metric tons CO <sub>2</sub> *)
Mt. Simon Formation	86,900
St. Peter Sandstone	35,300
Medina/Tuscarora Sandstone	28,200
Rose Run Sandstone	19,700
Oriskany Sandstone	7,800
Sylvania Sandstone	6,000
Wastegate Formation	1,800
Basal Conasauga Sandstones	1,700
Potsdam Sandstone	700
Rome Trough Sandstones	500
<b>Total Deep Saline</b>	<b>189,000</b>

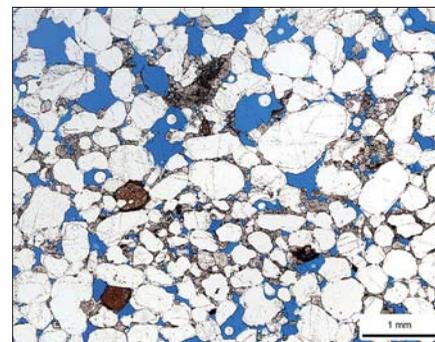
\*Based on National Atlas Methodology P85%.



The Mt. Simon Formation is a major deep saline rock target for geologic sequestration of CO<sub>2</sub>.



Saint Peter and Rose Run formations are other deep saline rock targets for carbon sequestration.

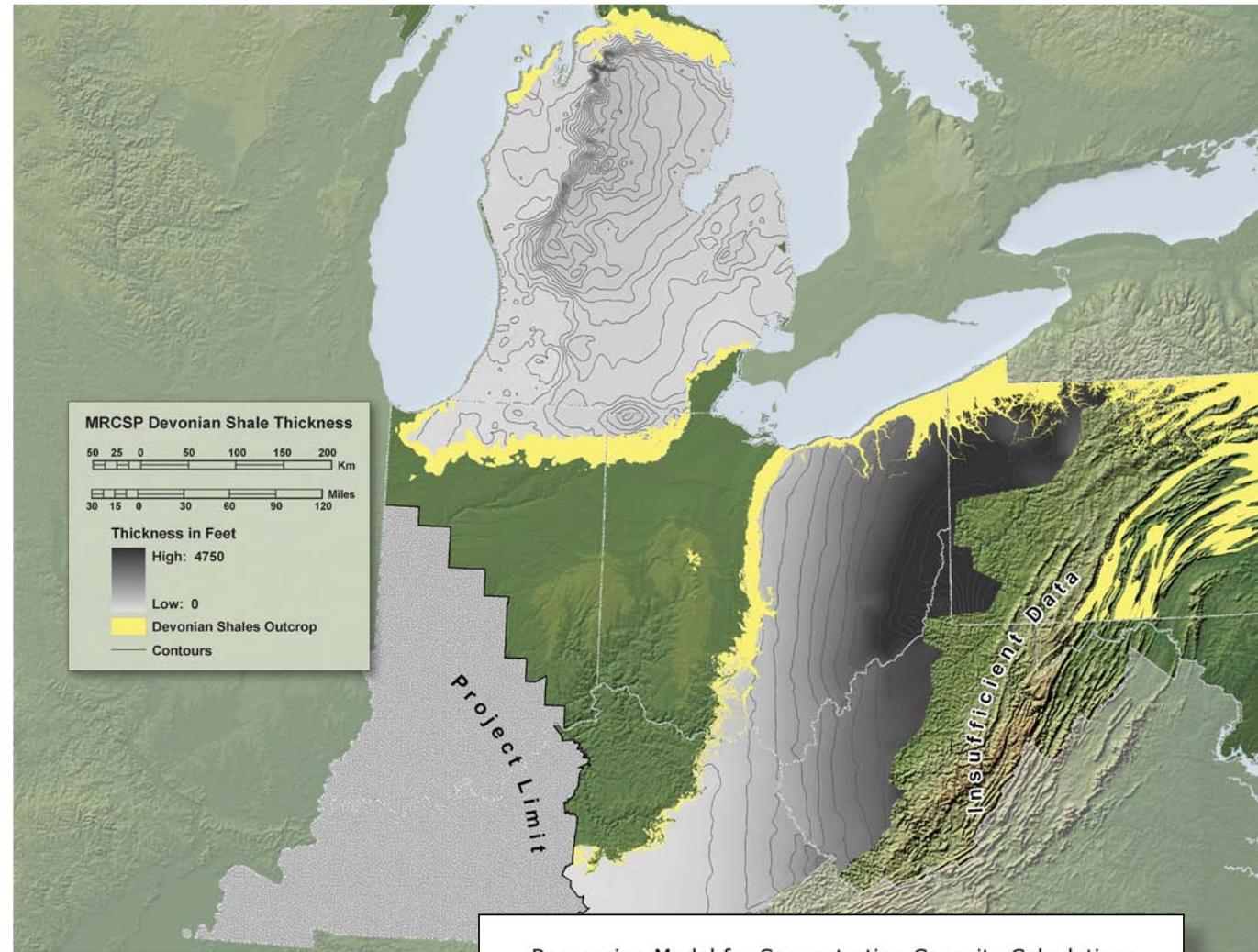


Thin section microscope view of pore space (shown in blue) of the Rose Run sandstone.

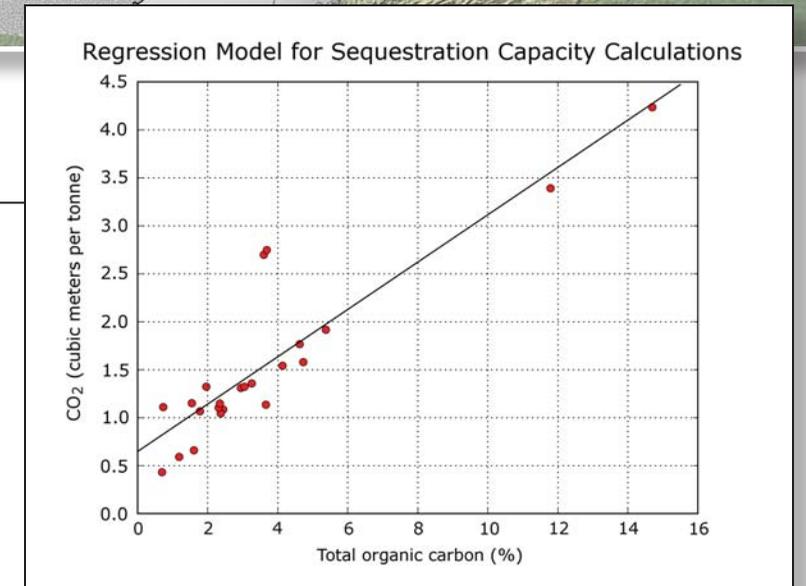
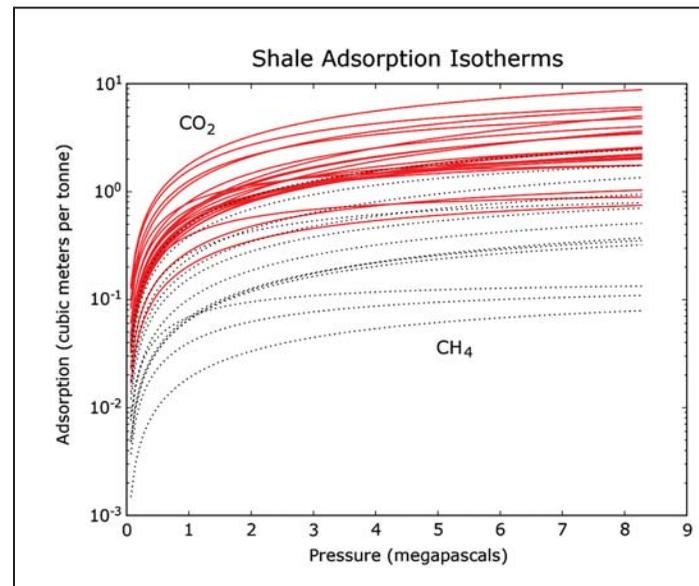
## MRCSP Deep Organic-Rich Shales

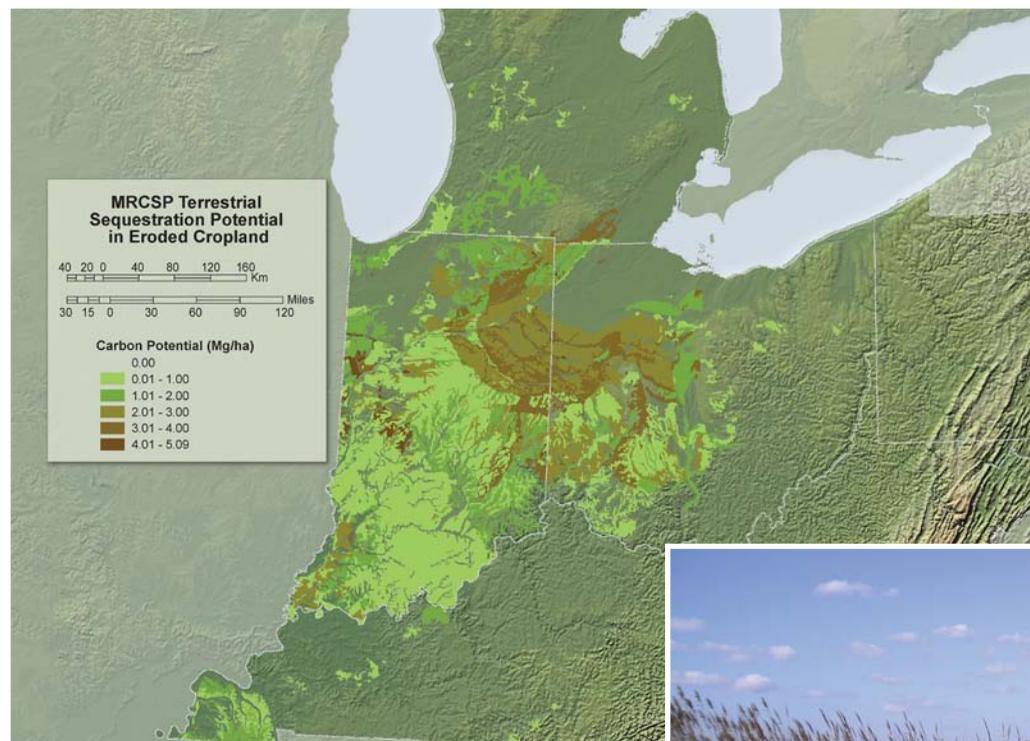
The MRCSP Region contains widespread, thick deposits of organic shales. These shales are interesting in that they are often multifunctional, acting as seals for underlying reservoirs, as source rocks for oil and gas reservoirs, and as unconventional gas reservoirs themselves. Analogous to sequestration in coal beds, CO<sub>2</sub> 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<sub>2</sub> into the shale, permitting long-term CO<sub>2</sub> 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 (49,600 million tons) of CO<sub>2</sub>.



An outcrop of the Devonian Ohio shale in eastern Kentucky





Restored tidal marshes at Blackwater National Wildlife Refuge, Maryland

## 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. More than 228,000 km<sup>2</sup> (88,000 mi<sup>2</sup>) of land in the MRCSP Region could be utilized for enhanced carbon sequestration. Studies of the Region have shown the potential to sequester 144 million metric tons (159 million tons) of CO<sub>2</sub> 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<sub>2</sub> per year). Tests are being conducted to demonstrate carbon sequestration through improved agriculture management practices for farmers in marginal and nonmarginal 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. Although the potential storage capacity is not as great in terrestrial systems as in geologic systems, terrestrial systems offer other benefits such as improvements in water quality, reduced fertilization use, habitat improvement, and reduced particulates that make terrestrial sequestration attractive in the Region.



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

Terrestrial Sequestration Potential in the MRCSP Region

Category	Area (Mha)	Sequestration Potential (million metric tons CO <sub>2</sub> /year)							
		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
<b>Total</b>	<b>22.8</b>	<b>33.5</b>	<b>18.8</b>	<b>5.9</b>	<b>30.2</b>	<b>27.2</b>	<b>19.1</b>	<b>9.6</b>	<b>144</b>

## MRCSP Field Tests

Given the diversity of storage opportunities in the Region, the overall approach for the MRCSP field tests is to evaluate many different sequestration options in real-world settings. 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 including the Appalachian Basin, Cincinnati Arch, and Michigan Basin. Tests will be performed at existing power plants in Eastern Ohio and Northern Kentucky and an oil and gas field in the northern portion of lower Michigan. The general methodology for each site is to characterize the deep rock layers, drill test wells, perform limited CO<sub>2</sub> injection tests, monitor the injected CO<sub>2</sub>, 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.

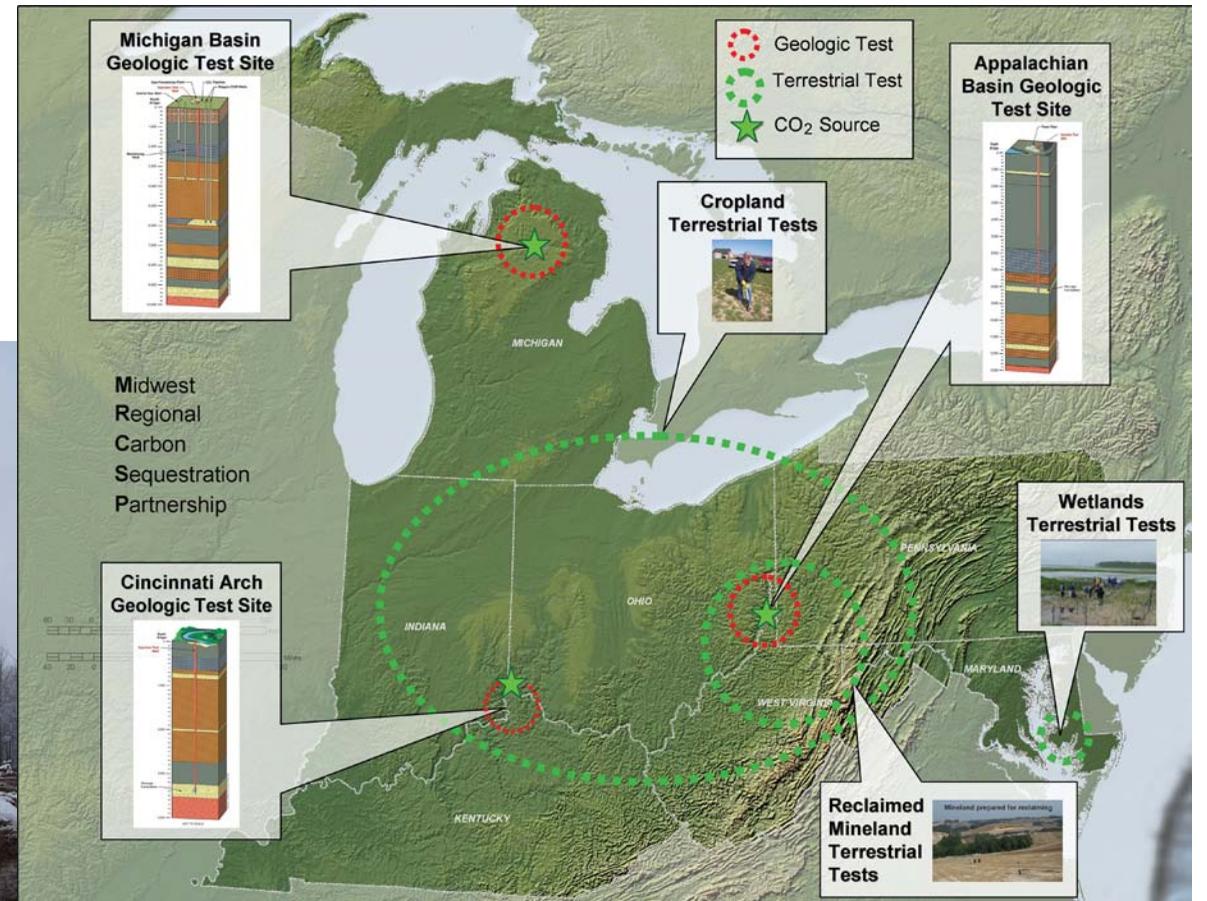
Along with the field tests, a thorough stakeholder outreach effort is underway to communicate project progress to the local community, general public, and scientific community. In addition, research is being performed to develop a regulatory framework for sequestration, characterize additional geologic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



Appalachian Basin geologic test site.



Cropland terrestrial sequestration test site.



Seismic survey for Appalachian Basin site.



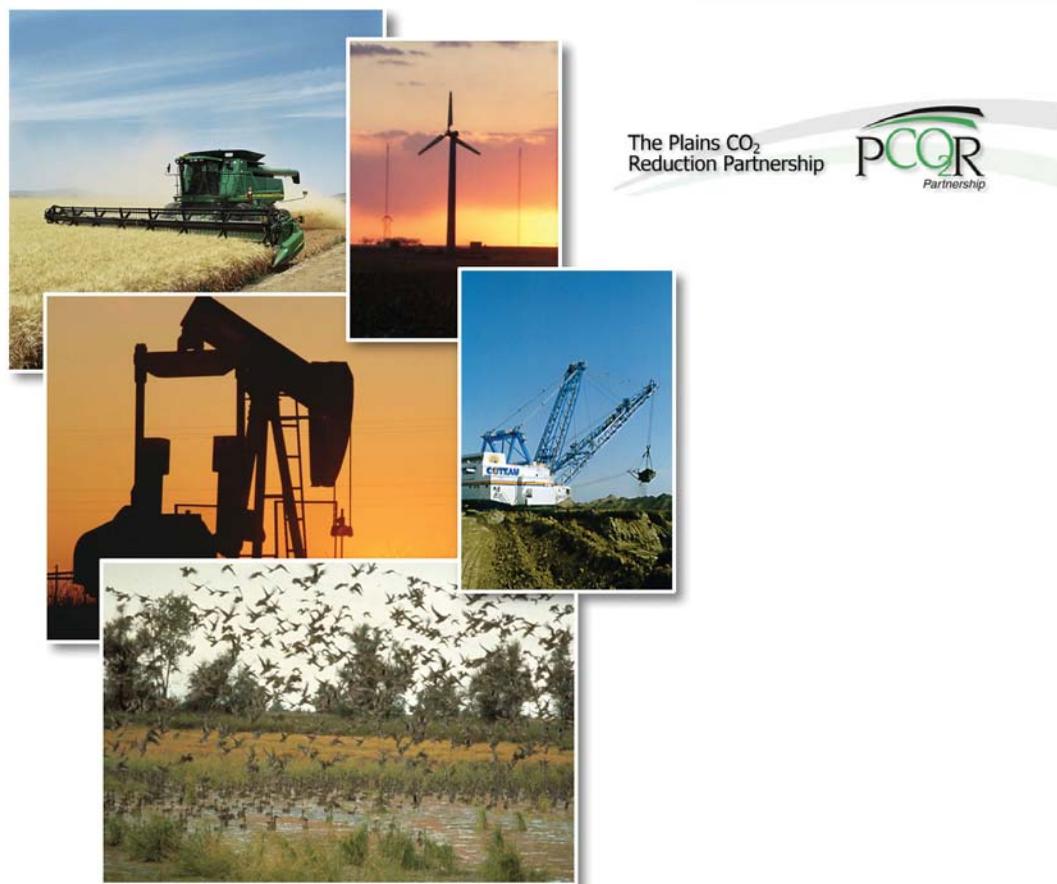
# The Plains CO<sub>2</sub> Reduction Partnership

The Plains CO<sub>2</sub> Reduction (PCOR) Partnership is investigating various aspects of sequestration technologies to provide a safe, effective, and efficient means of managing the carbon dioxide emissions across central North America.

The regional characterization activities conducted by the PCOR Partnership confirmed that while numerous large stationary CO<sub>2</sub> sources are available, the Region also has tremendous capacity for CO<sub>2</sub> sequestration. The varying natures of the sources and sequestration sites reflect the geographic and socioeconomic diversity across this nearly 3.6 million km<sup>2</sup> (1.4 million mi<sup>2</sup>) 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 U.S. 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 that stretches from northwestern Iowa, across the Dakotas, and into Saskatchewan and Alberta holds promise as an area that can be transformed into a significant terrestrial CO<sub>2</sub> sequestration site.

Deep beneath the surface of the Region lay geologic formations that hold tremendous potential to store CO<sub>2</sub>. Oil fields, already considered to be capable of sequestering CO<sub>2</sub>, can be found in roughly half the Region, while formations of limestone, sandstone, and coal suitable for CO<sub>2</sub> 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-capacity sequestration sites and, in some cases, key infrastructure is already in place.

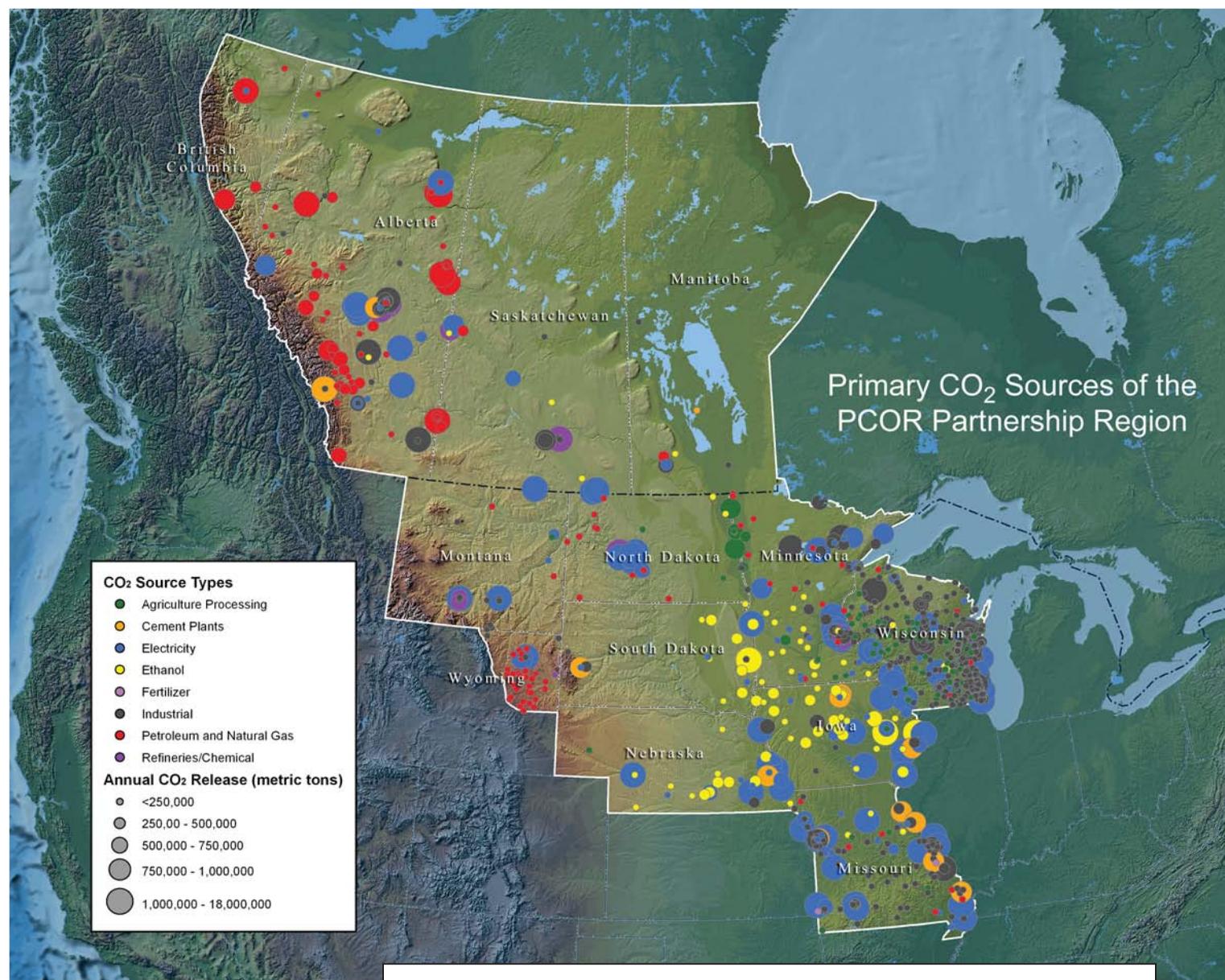
The PCOR Partnership is a collaboration of more than 60 public- and private-sector stakeholders from the central interior of North America and adjacent areas that have expertise in power generation, energy exploration and production, geology, engineering, the environment, agriculture, forestry, and economics. Our partners are the backbone of the PCOR Partnership and provide data, guidance, and practical experience with direct and indirect sequestration, including value-added projects.



## CO<sub>2</sub> Sources in the PCOR Partnership Region

The PCOR Partnership project has identified, quantified, and categorized 1,106 stationary CO<sub>2</sub> sources in the Region. These stationary sources have a combined annual CO<sub>2</sub> output of nearly 505 million metric tons (556 million tons). Although not a target source of CO<sub>2</sub> for direct sequestration, the transportation sector contributes nearly 202 million additional metric tons of CO<sub>2</sub> to the atmosphere every year.

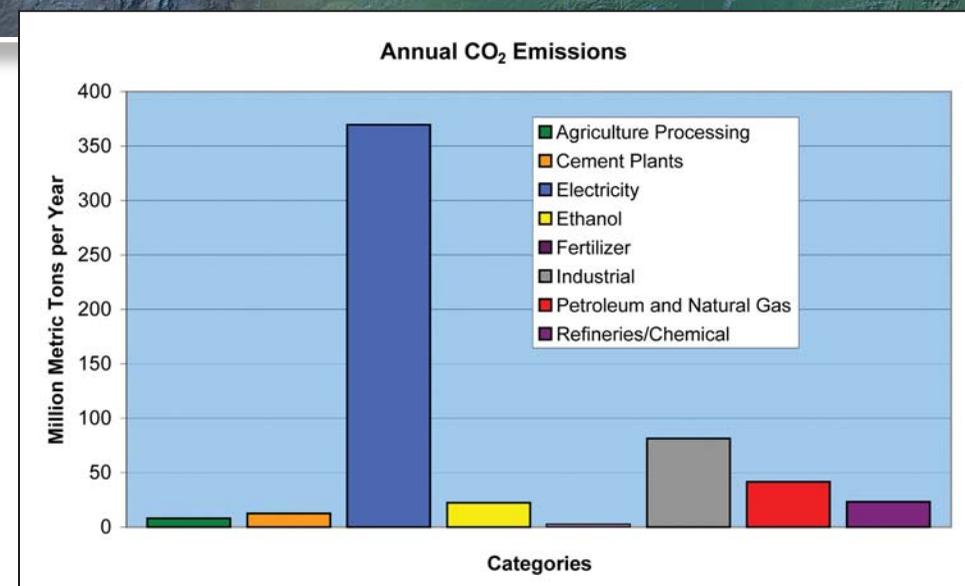
The annual output from the various stationary sources ranges from 9 million to 16 million metric tons (10 million to 18 million tons) for the larger coal-fired electric generation facilities to under 4,500 metric tons (4,960 tons) for industrial and agricultural processing facilities. For the most part, the distribution of the sources with the largest CO<sub>2</sub> output is coincident with the availability of fossil fuel resources, namely, coal 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 and southeastern Wisconsin.



American Crystal Sugar Company plant.



Coal-fired generation plant in North Dakota.



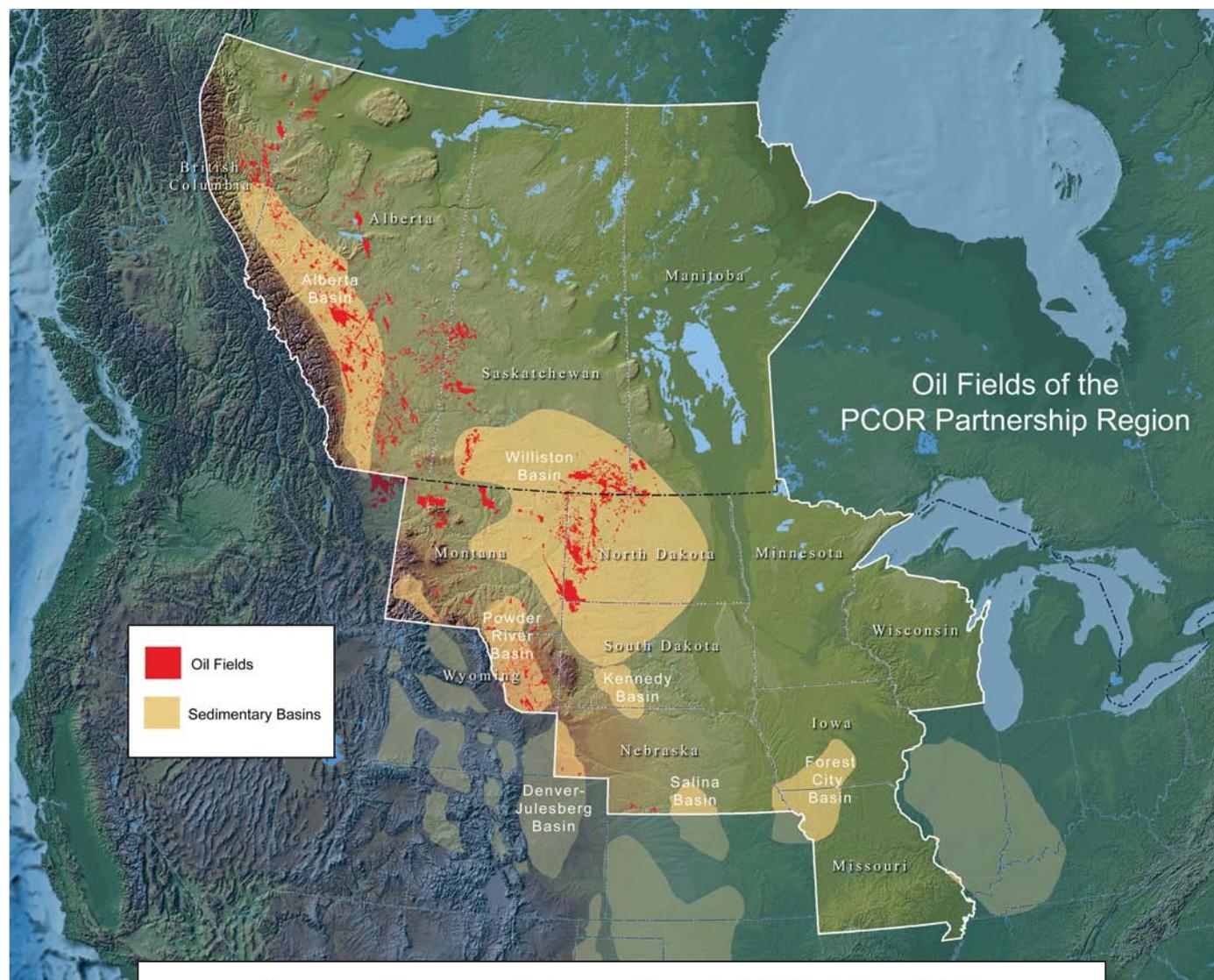
## PCOR Partnership Oil Fields

The geology of CO<sub>2</sub> 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<sub>2</sub>. Therefore, the geologic conditions that are conducive to hydrocarbon sequestration are also the conditions that are conducive to CO<sub>2</sub> sequestration. The three requirements for sequestering hydrocarbons are a hydrocarbon source, a suitable reservoir, and an impermeable trap. These requirements are the same as for sequestering CO<sub>2</sub>, except that the source is artificial and the reservoir is referred to as a sequestration site.

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 vary for each state or province. Once injected into an oil field, CO<sub>2</sub> may be sequestered in a pool through dissolution into the formation fluids (oil and/or water), as a buoyant supercritical-phase CO<sub>2</sub> 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<sub>2</sub>, formation waters, and the formation rock matrix.

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

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<sub>2</sub>.



Storage and Incremental Recovery Through EOR<sup>a</sup> in Selected Fields

Basin	Cummulative Incremental Recovery, million stb	CO <sub>2</sub> Required, <sup>b</sup> Bcf	CO <sub>2</sub> Sequestration Potential, Bcf	CO <sub>2</sub> Sequestration Potential, tonnes
Williston	1023	8186	8186	455,223,886
Powder River	381	3049	3049	169,563,509
Denver–Julesberg	25	199	199	11,076,137
Alberta	NA	8888 <sup>c</sup>	8888 <sup>c</sup>	494,315,000 <sup>c</sup>

<sup>a</sup> Enhanced oil recovery.

<sup>b</sup> CO<sub>2</sub> quantity required is the total purchase amount and does not consider recycling of CO<sub>2</sub> from the tertiary recovery operation.

<sup>c</sup> Values for the Alberta Basin were determined using a different methodology than the other basins and, therefore, may not be directly comparable to the other estimates. They are included in the table to provide insight regarding the general magnitude of CO<sub>2</sub> flood-related sequestration capacity and potential incremental oil production in Alberta.

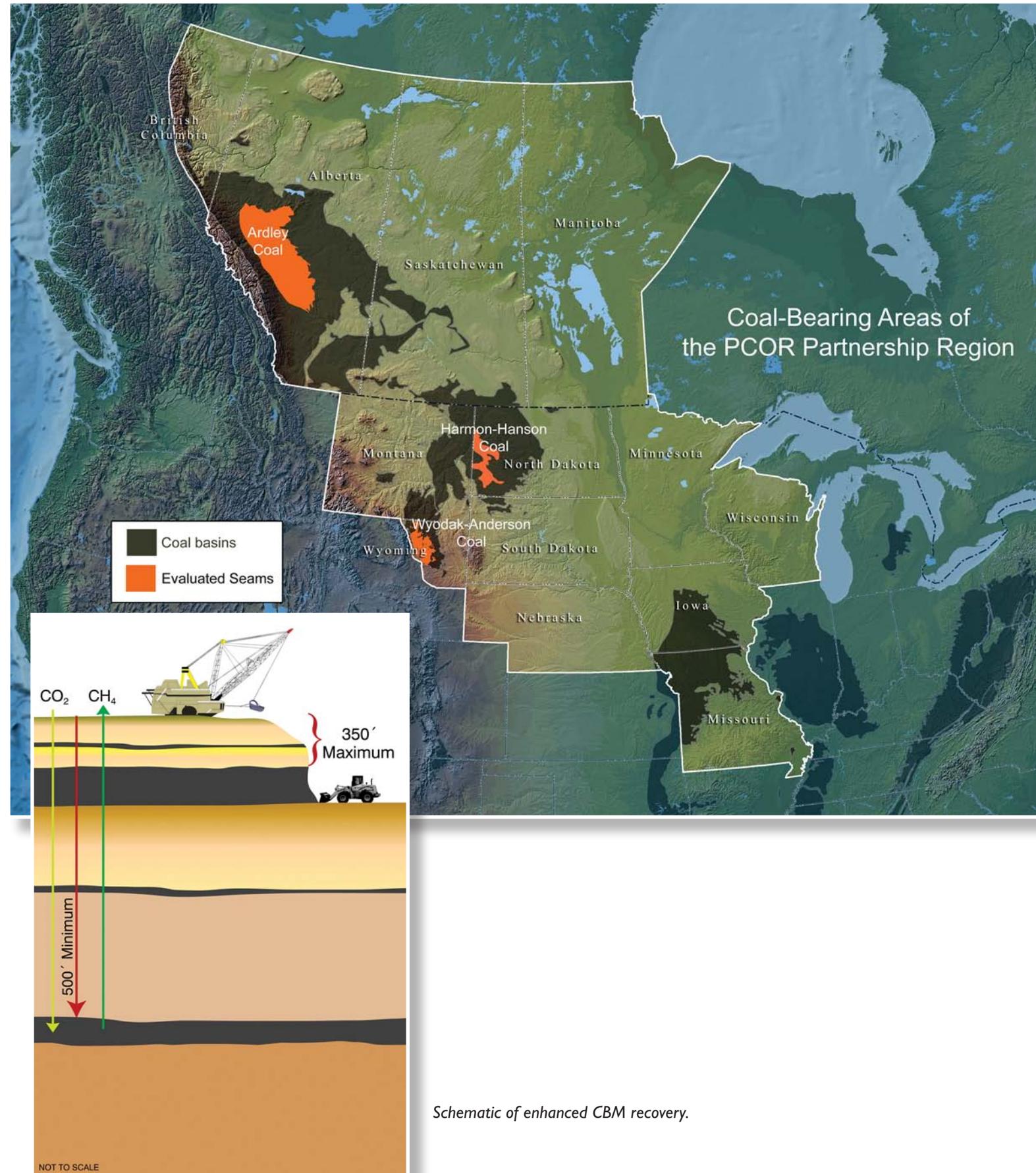
## PCOR Partnership Unmineable Coal Seams

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 CBM. In fact, CBM is the fastest growing source of natural gas in the U.S. 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<sub>2</sub>, which preferentially adsorbs onto the surface of the coal, releasing the methane. For the coals in the PCOR Partnership Region, up to 13 molecules of CO<sub>2</sub> can be adsorbed for each molecule of methane released, thereby providing an excellent storage site for CO<sub>2</sub>. Just as with depleting oil reservoirs, unmineable coal beds are a good opportunity for CO<sub>2</sub> 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 total maximum CO<sub>2</sub> sequestration potential for all three coal horizons is approximately 7.3 billion metric tons (8.0 billion tons).

In northeastern Wyoming, the CO<sub>2</sub> 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 sequester all of the current annual CO<sub>2</sub> emissions from nearby power plants for approximately the next 150 years.

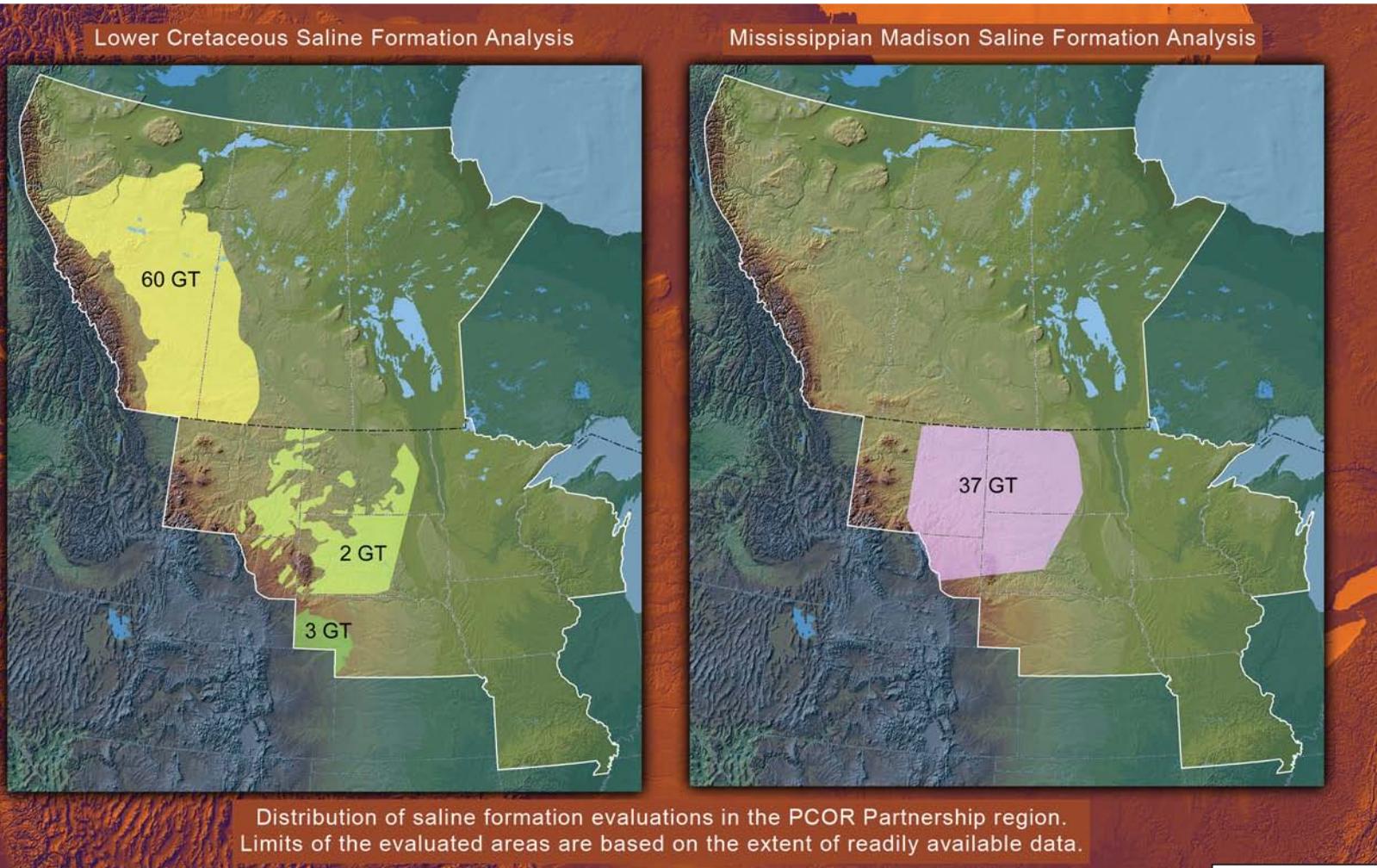


Schematic of enhanced CBM recovery.

## PCOR Partnership Deep Saline Formations

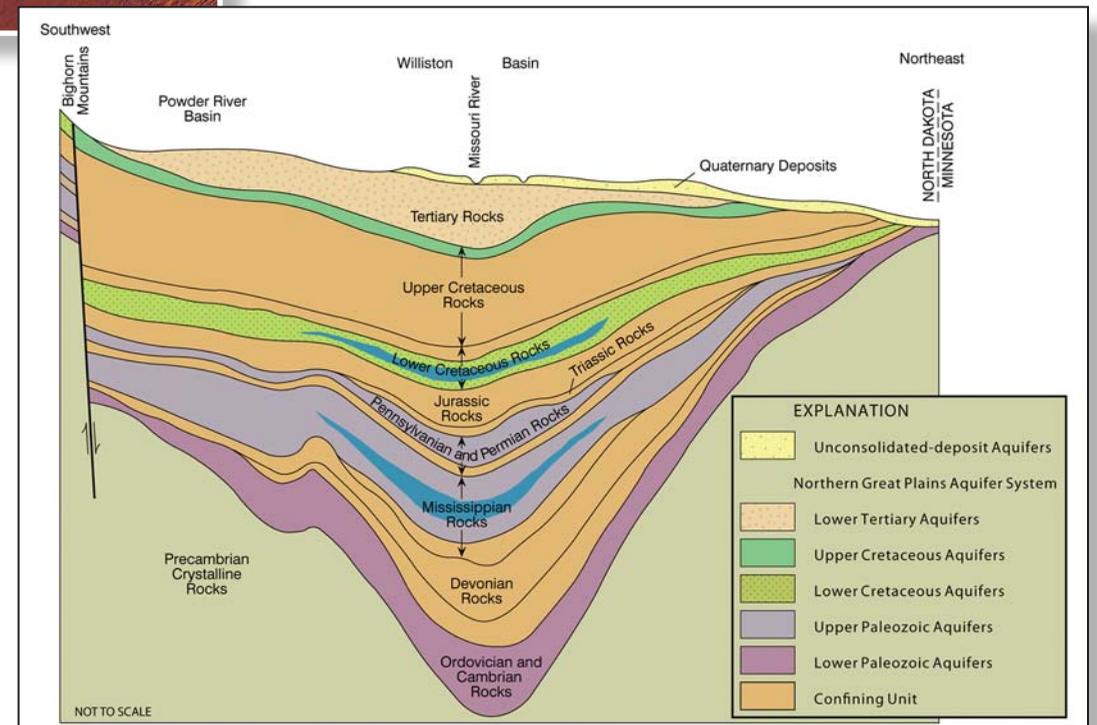
Saline formations within the PCOR Partnership Region have the potential to store vast quantities of anthropogenic CO<sub>2</sub>. Two saline formations, the Mississippian Madison and the Lower Cretaceous, have been evaluated for their regional continuity, hydrodynamic characteristics, fluid properties, and ultimate storage capacities using published data.

The lateral extent of these reservoirs, the current understanding of their storage potential gained through injection well performance, and the geographic proximity to major CO<sub>2</sub> sources suggest they may be suitable sequestration sites for future storage needs. For example, reconnaissance-level calculations on the Mississippian System in the Williston Basin and Powder River Basin suggest the potential to store upwards of 37 billion metric tons (41 billion tons) of CO<sub>2</sub> over the evaluated Region, while the Cretaceous system has the potential to store over 65 billion metric tons (72 billion tons.)



Distribution of saline formation evaluations in the PCOR Partnership region. Limits of the evaluated areas are based on the extent of readily available data.

Formation	Basin	Estimated CO <sub>2</sub> Capacity (billion tonnes)
<b>Lower Cretaceous System</b>		
Newcastle Formation	Williston and Powder River	2
Viking Formation	Alberta	60
Maha Formation	Denver-Julesberg	3
<b>Mississippian System</b>		
Madison Formation	Williston and Powder River	37



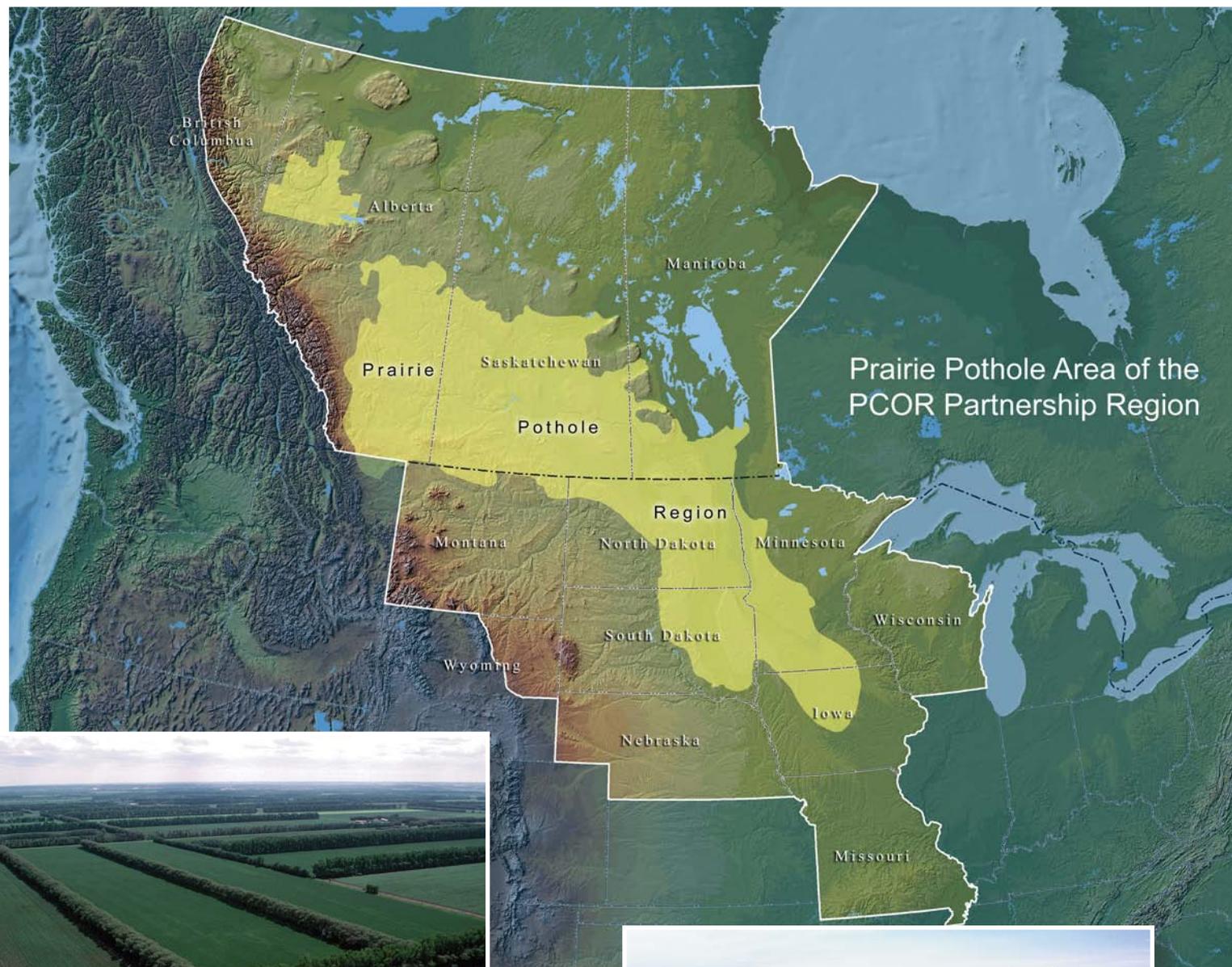
Geologic cross section showing the position of deep saline formations.

## PCOR Partnership Terrestrial Sequestration

In contrast to direct sequestration deep within the earth, the concept of terrestrial sequestration focuses on a more passive mechanism of CO<sub>2</sub> 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, 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 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 899,000 km<sup>2</sup> (347,000 mi<sup>2</sup>) and includes portions of Iowa, Minnesota, Montana, North Dakota, and South Dakota in the U.S. 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 190,000 m<sup>2</sup> (73,000 mi<sup>2</sup>) of wetlands, making it the largest wetland complex in North America. However, the abundance of fertile soils in this Region heralded 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.

Recent work by U.S. Geological Survey and Ducks Unlimited, Inc., scientists for the PCOR Partnership conducted at wetlands study sites demonstrated that restoration of previously farmed wetlands results in the rapid replenishment of SOC lost to cultivation at an average rate of 250 metric tons/km<sup>2</sup>/yr (710 tons/mi<sup>2</sup>/yr). Restored prairie wetlands provide a unique and previously overlooked opportunity to store atmospheric carbon in the PCOR Partnership Region.



Prairie pothole region, North Dakota.



## PCOR Partnership Field Test Sites

**CO<sub>2</sub>-Rich Gas in a Pinnacle Reef Structure**—Acid gas (67 percent CO<sub>2</sub>, 33 percent hydrogen sulfide [H<sub>2</sub>S]) from natural gas-processing plants in northern Alberta, Canada, is being injected into an oil-producing zone in an underground pinnacle reef structure. Results will help to determine the best practices to support sequestration in these unique geologic structures as well as further our understanding of the effects of H<sub>2</sub>S on tertiary oil recovery and CO<sub>2</sub> sequestration.

**CO<sub>2</sub> in a Deep Oil Reservoir**—CO<sub>2</sub> will be injected into an oil-bearing zone at great depth in the Beaver Lodge oil field in northwestern North Dakota. The activity will be used to determine the efficacy of CO<sub>2</sub> sequestration and the use of CO<sub>2</sub> to produce additional oil from deep carbonate source rocks.

**CO<sub>2</sub> in an Unminable Lignite Seam**—CO<sub>2</sub> will be injected into unminable lignite seams in northwestern North Dakota. The injected CO<sub>2</sub> is trapped by naturally bonding to the surfaces of the fractured lignite. The injected CO<sub>2</sub> also has the potential to displace methane occupying the coal fractures. This validation test will give valuable information regarding lignites for both CO<sub>2</sub> sequestration and enhanced coalbed methane production.

**Out of the Air - Into the Soil**—A managed wetland will be implemented in north-central South Dakota to demonstrate practices that will improve CO<sub>2</sub> uptake. The results will help to optimize CO<sub>2</sub> storage, MM&V methods and facilitate the monetization of terrestrial carbon offsets in the Region and elsewhere.



Zama Region of Northern Alberta

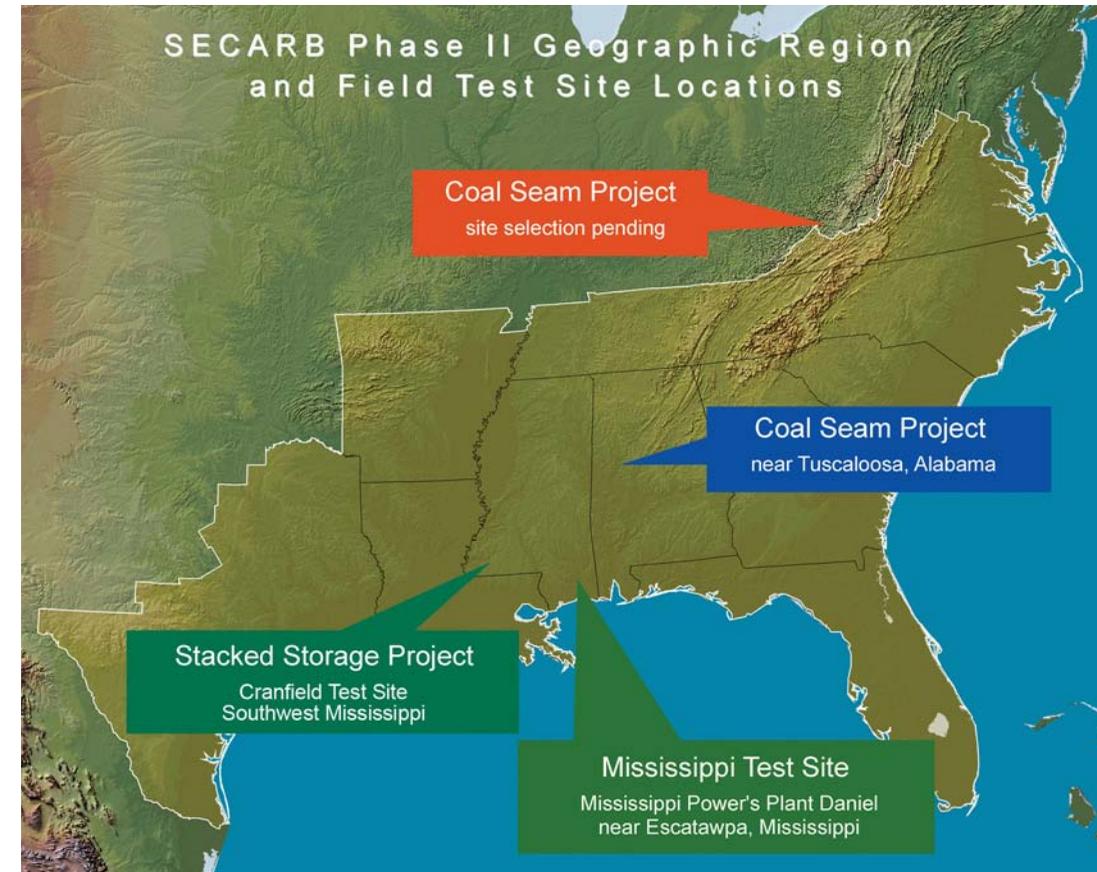
# Southeast Regional Carbon Sequestration Partnership

The Southeast Regional Carbon Sequestration Partnership (SECARB), encompasses an 11 state region including the 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.

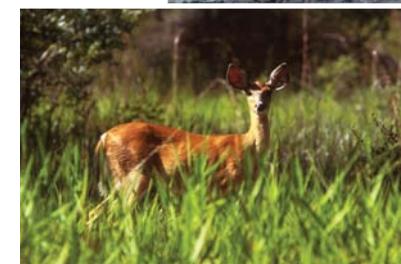
SECARB efforts focus on four diverse field tests comprised of phases aligned with project definition, design, implementation, operations, and closeout/reporting; continued characterization of regional sequestration opportunities; and cross-cutting services in education and outreach, regulatory and permitting, monitoring, measurement and verification, geographical information systems, and project management. SECARB will develop best-practices manuals to support regional transferability and wide-scale deployment. The field tests include the following

- Two Coal Seam Projects for validation of sequestration opportunities in the Black Warrior Basin Central and the Appalachian Basin, where CO<sub>2</sub> ECBM recovery operations can add economic value and where unmineable coals can provide sequestration opportunities;
- The Mississippi test site will focus on validating geologic storage in a deep, saline reservoir. The test will be conducted at Mississippi Power Company's Victor J. Daniel, Jr. power plant, a coal-fired facility near Escatawpa, Mississippi; and
- A Gulf Coast Stacked Storage Project that builds upon the Gulf Coast Carbon Center of The University of Texas Bureau of Economic Geology's experience managing the Frio Basin Project and investigates a stacked sequence of hydrocarbon and brine reservoir intervals, where EOR with CO<sub>2</sub> can serve as an economic driver in establishing the CO<sub>2</sub> infrastructure for transportation and storage into underlying deep saline formations.

Each field team has assumed responsibility for the technical scope of work, local education and outreach, permitting, MM&V and maintaining the validation test's schedule and budget. In addition, a task has been dedicated to integrating field data and filling gaps in regional characterization data sets. Data and tools developed in this task will be incorporated into a relational database and GIS.



Coal seam.

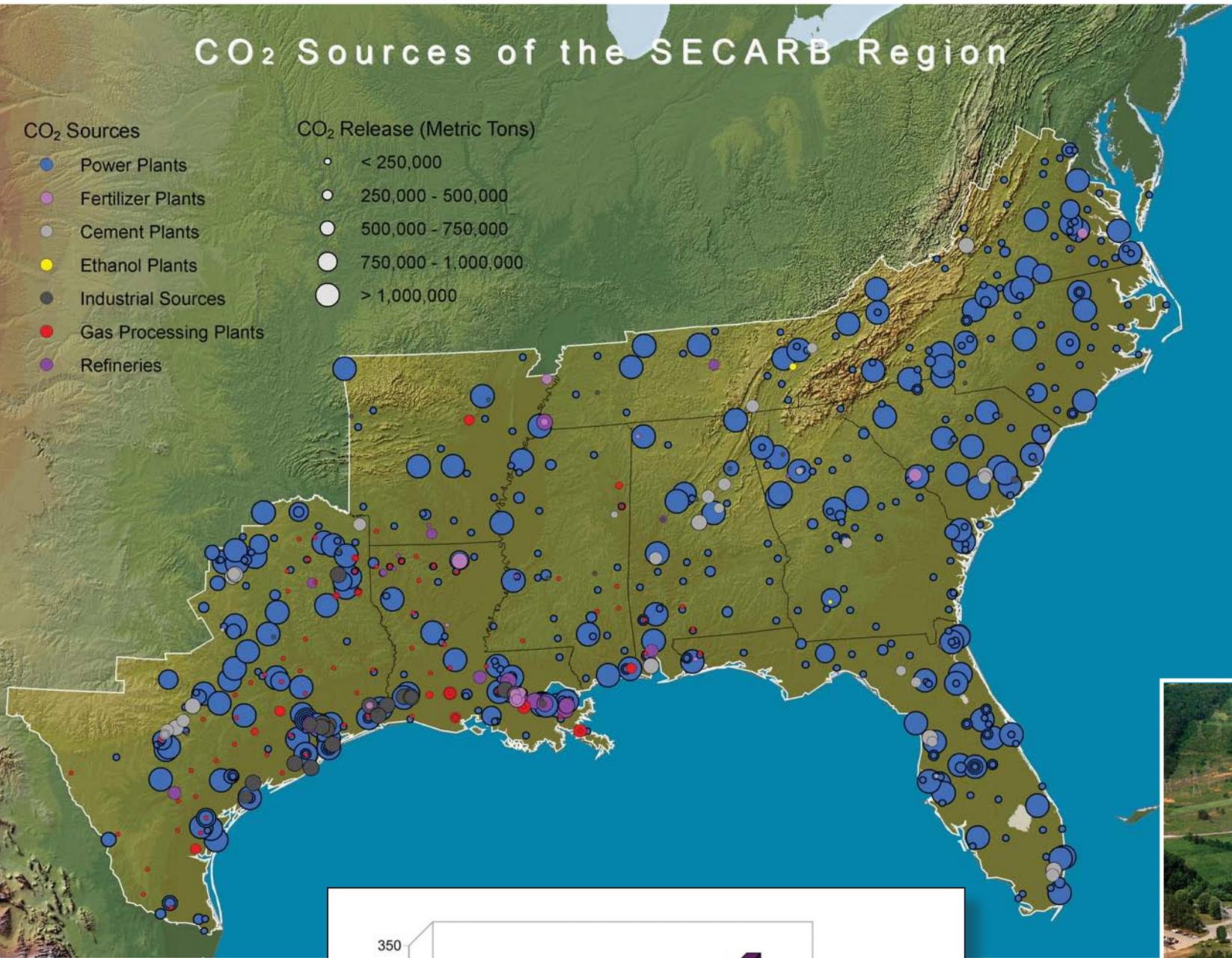


Credit: U.S. Fish and Wildlife Service



### CO<sub>2</sub> Sources of the SECARB Region

- | CO <sub>2</sub> Sources | CO <sub>2</sub> Release (Metric Tons) |
|-------------------------|---------------------------------------|
| ● Power Plants          | ○ < 250,000                           |
| ● Fertilizer Plants     | ○ 250,000 - 500,000                   |
| ● Cement Plants         | ○ 500,000 - 750,000                   |
| ● Ethanol Plants        | ○ 750,000 - 1,000,000                 |
| ● Industrial Sources    | ○ > 1,000,000                         |
| ● Gas Processing Plants |                                       |
| ● Refineries            |                                       |

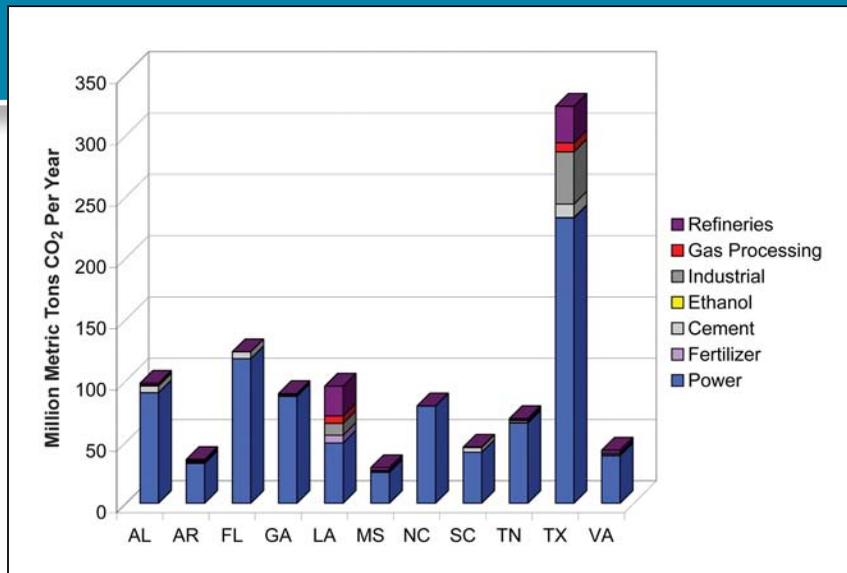


### SECARB CO<sub>2</sub> Sources

More than 800 large, stationary sources of CO<sub>2</sub> in the SECARB Region are potential targets for carbon sequestration. Their total annual emissions are estimated at just over 1 billion metric tons (1.1 billion tons) of CO<sub>2</sub>. Fossil-fueled (coal, gas, oil) power plants are the largest contributors, accounting for approximately 85 percent of the total CO<sub>2</sub> emissions.

The SECARB Region is also host to a number of nonpower-related stationary sources of CO<sub>2</sub>. These include, in descending order of contribution of CO<sub>2</sub>, refineries, ethylene plants, cement plants, gas processing plants, ammonia plants, iron and steel plants, and ethylene oxide plants.

CO<sub>2</sub> emissions for the SECARB Region are displayed in the chart (right) and map (above) by location, source type, and quantity.



Colbert coal-fired power plant, Alabama, emits around 8 million metric tons (9 million tons) of CO<sub>2</sub> per year (source: Tennessee Valley Authority).

## SECARB Oil and Gas Reservoirs

The SECARB Region, particularly Louisiana and eastern Texas, is an area with a rich history of oil and gas production. As such, considerable information exists on the geological settings and reservoir properties of these potential CO<sub>2</sub> storage sites.

The Region has produced nearly 7 billion m<sup>3</sup> (44 billion barrels) of oil and nearly 9.4 trillion m<sup>3</sup> (332 trillion ft<sup>3</sup>) of natural gas. Application of CO<sub>2</sub> EOR could add 2.1 billion m<sup>3</sup> (13 billion barrels) of oil to these totals. These oil and gas reservoirs provide opportunities for storing CO<sub>2</sub>, assuming that the water and low pressure gas occupying this pore space can be efficiently displaced with injected CO<sub>2</sub>.

The CO<sub>2</sub> storage capacity 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<sub>2</sub>, given the presence of a porous and permeable reservoir overlain by a competent caprock.

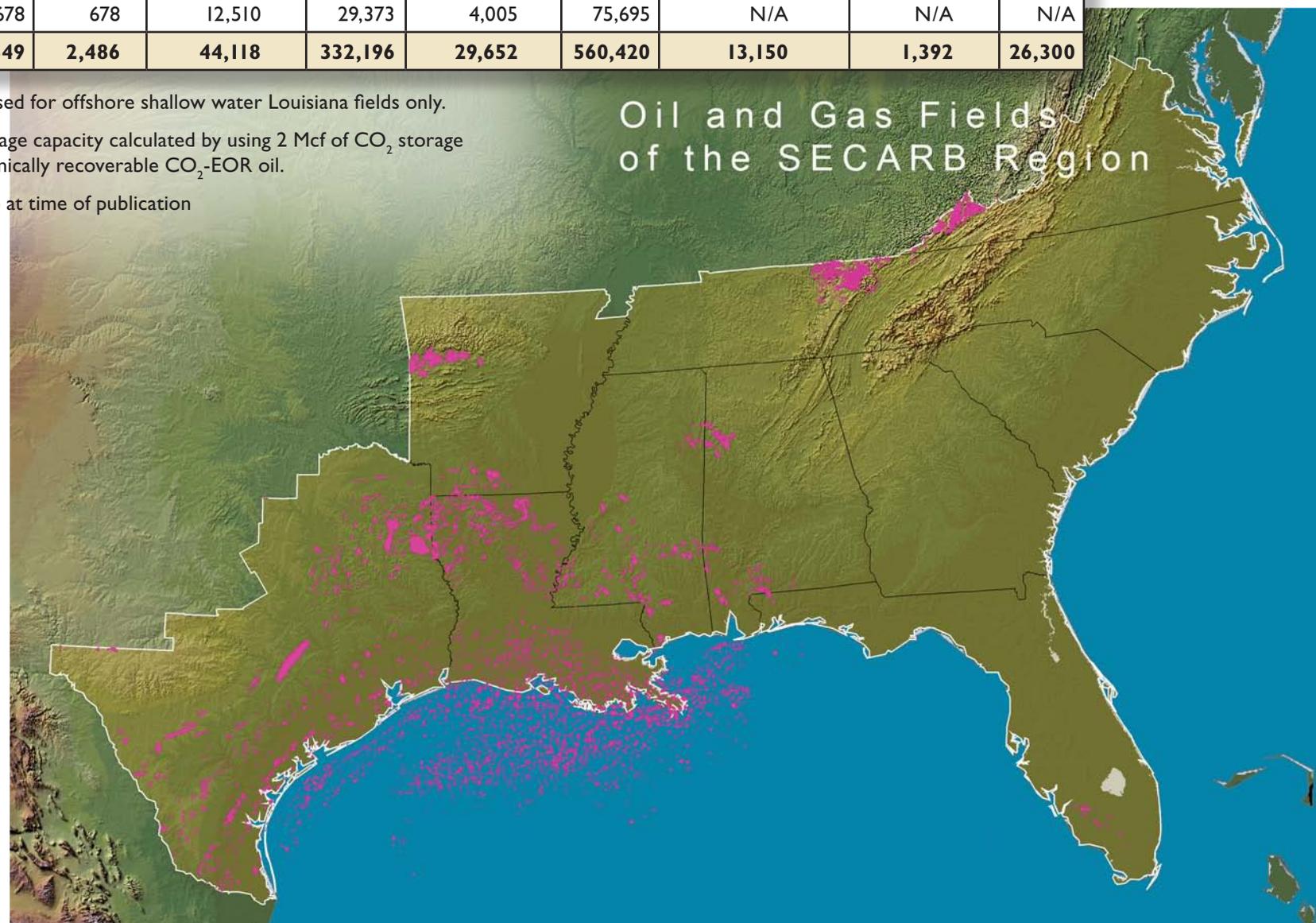
Thus, the SECARB Region offers the potential for integrated application of CO<sub>2</sub> EOR and CO<sub>2</sub> sequestration, helping to accelerate the storage of CO<sub>2</sub> in the Region.

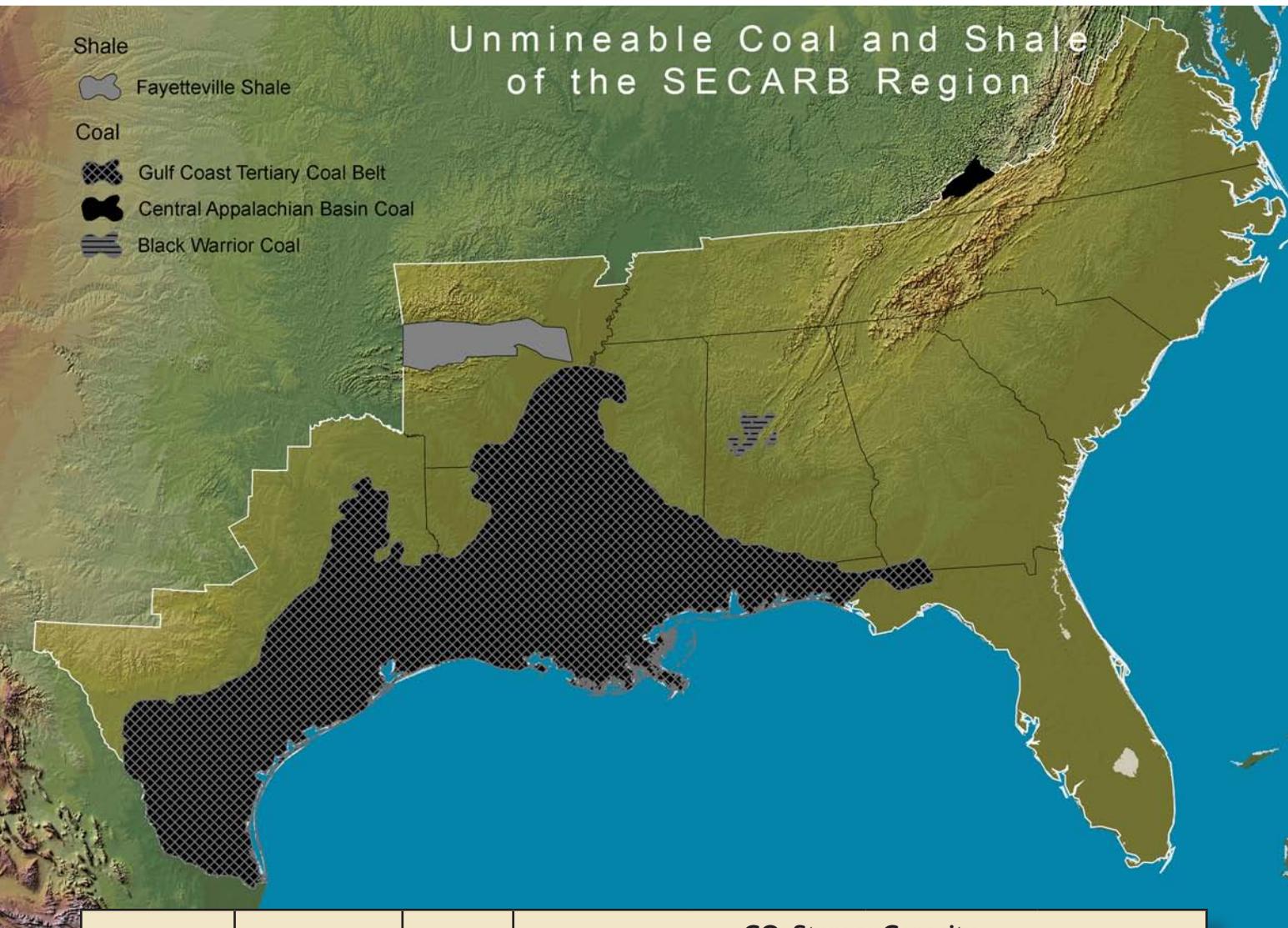
State	Number of Fields		Cumulative Recovery		Conventional CO <sub>2</sub> Storage Capacity		Technically Recoverable Oil from CO <sub>2</sub> -EOR	Additional CO <sub>2</sub> Storage Capacity**	
	Total	Assessed	Oil (Million Bbls)	Gas (Bcf)	(Million Metric Tons)	(Bcf)	(Million Bbls)	(Million Metric Tons)	(Bcf)
Alabama	133	63	622	1,856	344	6,504	410	43	820
Florida	23	8	556	0	109	2,061	180	19	360
Mississippi	110	101	1,346	5,300	399	7,549	850	90	1,700
Louisiana	964	331	11,847	117,697	6,781	128,153	5,480	580	10,960
Arkansas	42	42	1,394	1,415	250	4,728	340	36	680
Virginia	49	49	–	89	10	180	–	–	–
Tennessee	213	213	–	–	–	–	–	–	–
Federal Offshore	1,337	1,001	15,843	176,466	17,754	335,550	5890*	623	11,780
Texas	678	678	12,510	29,373	4,005	75,695	N/A	N/A	N/A
<b>TOTAL</b>	<b>3,549</b>	<b>2,486</b>	<b>44,118</b>	<b>332,196</b>	<b>29,652</b>	<b>560,420</b>	<b>13,150</b>	<b>1,392</b>	<b>26,300</b>

\* CO<sub>2</sub>-EOR assessed for offshore shallow water Louisiana fields only.

\*\* Additional storage capacity calculated by using 2 Mcf of CO<sub>2</sub> storage per barrel of technically recoverable CO<sub>2</sub>-EOR oil.

N/A Not available at time of publication





## 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 hold from 308–818 million metric tons (340–902 million tons) of CO<sub>2</sub> storage capacity. The second coal basin, the Black Warrior Basin in Alabama and Mississippi, has a potential storage capacity of 467 million metric tons (515 million tons) of CO<sub>2</sub>. The third coal basin, the areally extensive Gulf Coast Tertiary Coal Belt, may hold from 43–61 billion metric tons (47–67 billion tons) of CO<sub>2</sub>. However, additional information is needed to more rigorously quantify this large potential CO<sub>2</sub> storage option.

The one gas shale basin in this Region appraised to date, the Fayetteville Shale in the Arkoma Basin of Arkansas and Oklahoma, may hold 14–20 billion metric tons (15–22 billion tons) of CO<sub>2</sub> storage capacity. (The large Barnett Shale gas play in the Fort Worth Basin has yet to be appraised.)

Considerable technical uncertainty surrounds the efficient utilization of the large, available CO<sub>2</sub> storage capacity offered by coal seams and gas shales, particularly with respect to CO<sub>2</sub> injectivity and injection well requirements. The two SECARB field tests, in the Central Appalachian and the Warrior basins, will help reduce this uncertainty.

Basin	Status of Development	Area (Square Miles)	CO <sub>2</sub> Storage Capacity			
			Billion Cubic Feet (Bcf)		Million Metric Tons	
			High Estimate P(15)	Low Estimate P(85)	High Estimate P(15)	Low Estimate P(85)
<b>COAL</b>						
Central Appalachian	Mature	1,269	15,460	5,821	818	308
Black Warrior	Mature	1,305	8,826		467	
Gulf Coast Tertiary Coal Belt	Undeveloped	160,317	1,148,364	803,817	60,760	42,530
<b>SHALE</b>						
Arkoma (Fayetteville)	Emerging	8,610	379,890	266,490	20,100	14,100

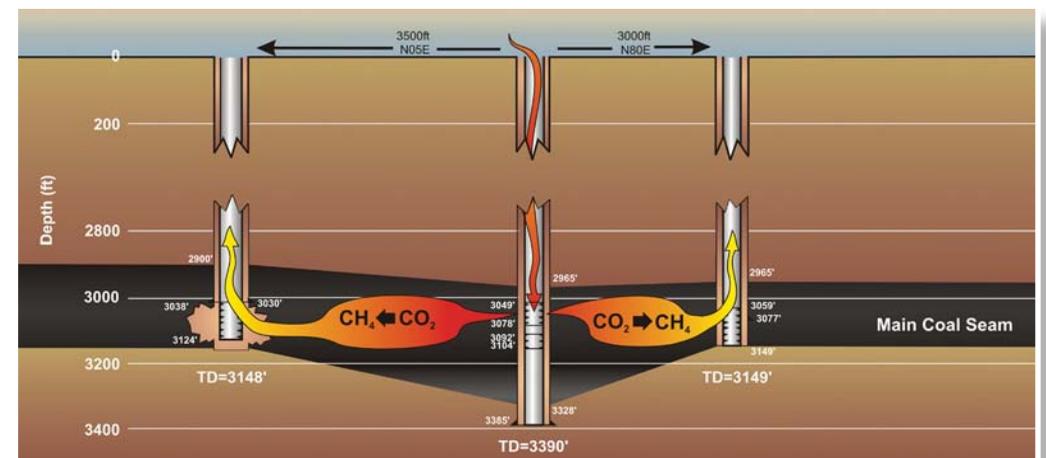


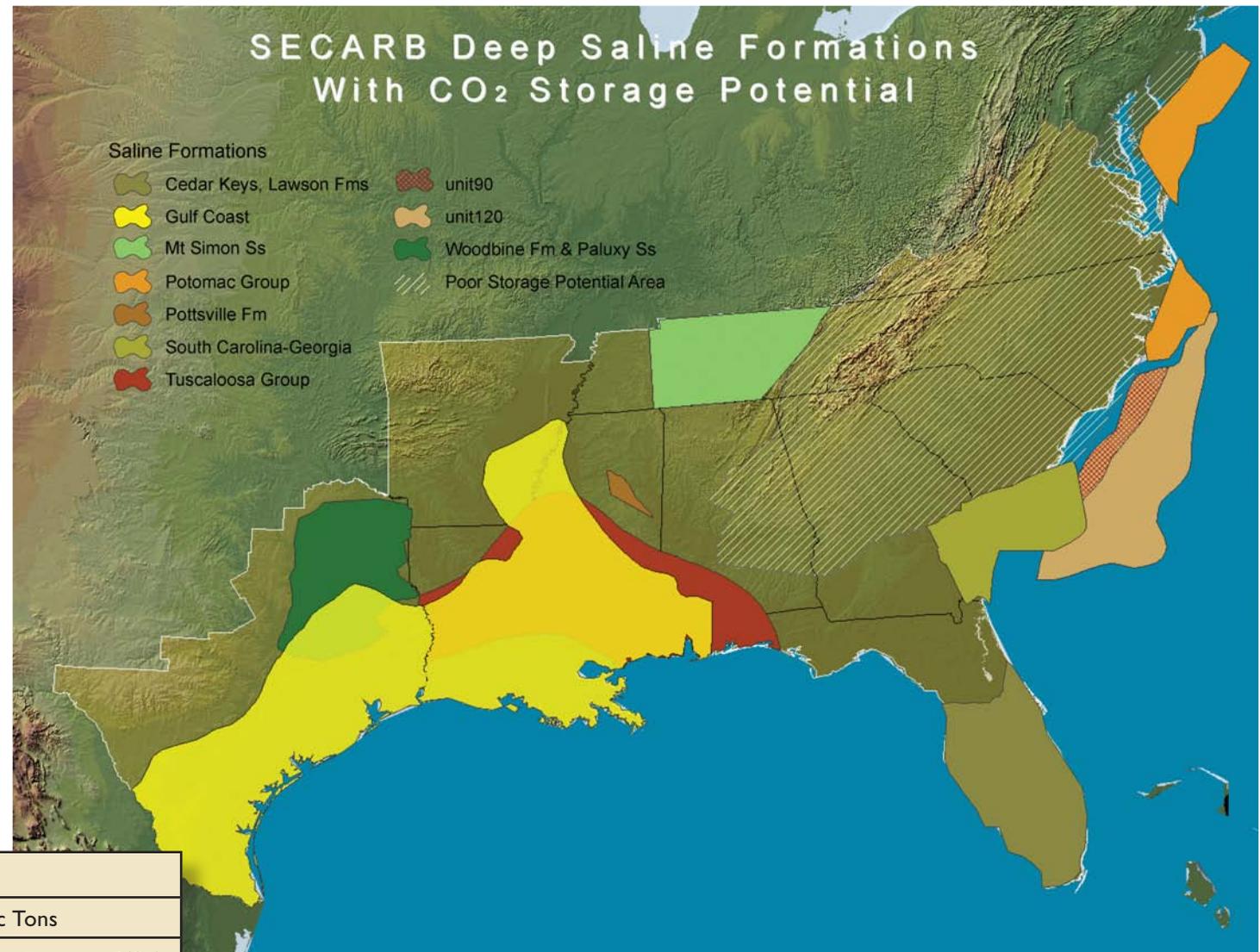
Diagram of CO<sub>2</sub> injection for enhanced CBM recovery.

## SECARB Deep Saline Formations

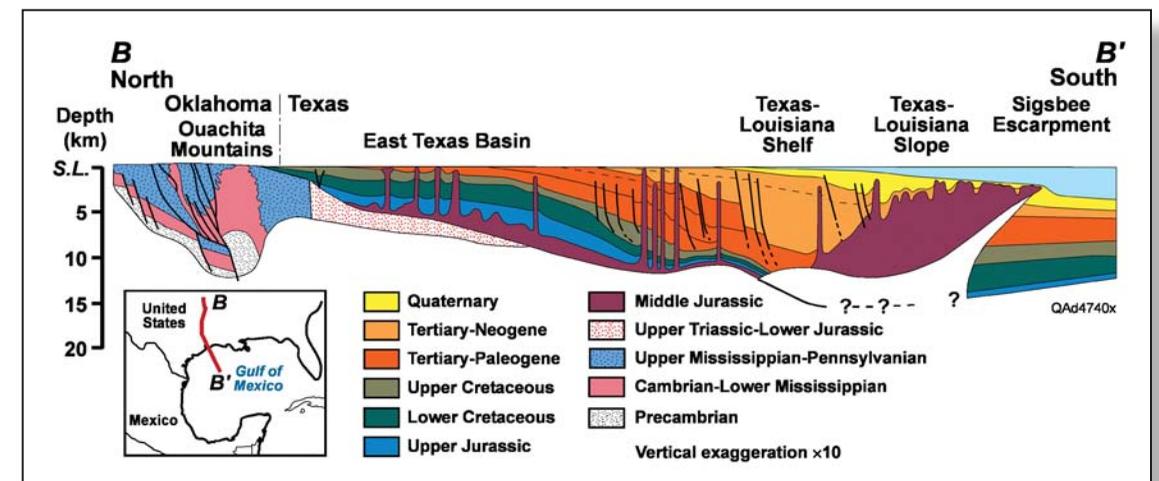
The Gulf Coast and interior salt basins in the SECARB Region provide numerous deep saline formations with large capacities for storing CO<sub>2</sub>. These include the Upper Cretaceous Tuscaloosa Group in Alabama, Mississippi, and Louisiana; the Woodbine and Paluxy Formations of Texas; and the Mt. Simon Sandstone in Tennessee. In addition, considerable potential for geologic storage exists in subsea formations in the offshore Atlantic. An initial assessment suggests that these formations have the potential to store from 350–1,400 billion metric tons (390–1,500 billion tons) of CO<sub>2</sub>.

Improved reservoir characterization, particularly full delineation of the internal architecture of these saline formations, are required for more precise estimates of CO<sub>2</sub> storage capacity.

Storage potential in the Appalachian Piedmont and Blue Ridge areas is poor to nonexistent because crystalline and metamorphic rocks at surface provide no predictable seal and have low porosity and permeability.

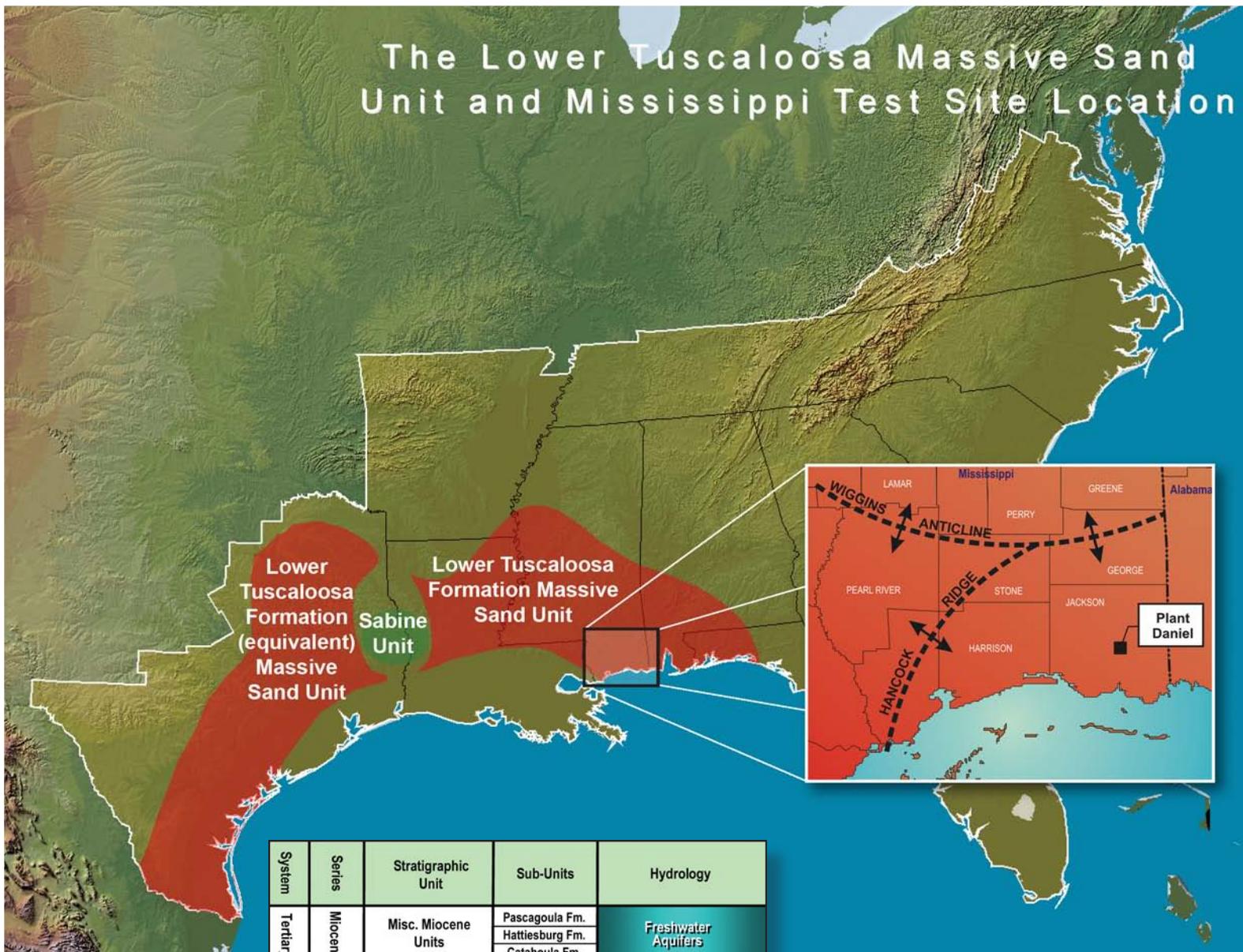


Saline Formations	CO <sub>2</sub> Storage Capacity			
	Billion Cubic Feet (Bcf)		Million Metric Tons	
	High Estimate P(15)	Low Estimate P(85)	High Estimate P(15)	Low Estimate P(85)
Gulf Coast Basins	13,419,989	3,356,017	710,264	177,567
Tuscaloosa Group	813,456	203,364	43,040	10,760
Woodbine and Paluxy Formations	962,633	240,654	50,933	12,733
Pottsville Formation	210,414	52,599	11,133	2,783
Mt. Simon Sandstone	94,500	23,625	5,000	1,250
Potomac Group	88,376	222,094	47,004	11,751
South Carolina-Georgia Basins	597,070	149,272	31,591	7,898
Cedar Keys, Lawson Formations	2,098,694	524,683	111,042	27,761
Offshore Atlantic (Unit 120)	6,732,936	1,683,234	356,240	89,060
Offshore Atlantic (Unit 90)	586,656	146,664	31,040	7,760
<b>Total</b>	<b>25,604,724</b>	<b>6,602,206</b>	<b>1,397,287</b>	<b>349,323</b>



Geologic formations along the Gulf Coast.

The Lower Tuscaloosa Massive Sand Unit and Mississippi Test Site Location



System	Series	Stratigraphic Unit	Sub-Units	Hydrology
Tertiary	Miocene	Misc. Miocene Units	Pascagoula Fm.	Freshwater Aquifers
			Hattiesburg Fm.	
Catahoula Fm.				
Cretaceous	Upper	Selma Chalk	Navarro Fm.	Confining unit
			Taylor Fm.	
		Eutaw	Austin Fm.	Confining unit
			Eagle Ford Fm.	Saline Reservoir
		Tuscaloosa Group	Upper Tusc.	Minor Reservoir
	Marine Tusc.		Confining unit	
	Lower Tusc.		Interbeds Massive Sand	Saline Reservoir
	Lower	Washita – Fredricksburg	Dantzier Fm.	Saline Reservoir
			"Limestone Unit"	



## SECARB Field Tests

### Saline Formation Pilot Test

#### The Mississippi Test Site

The purpose of the project is to evaluate a major deep saline reservoir—the Massive Sand Unit of the Lower Tuscaloosa Formation along the Mississippi Gulf Coast—for geologic storage of CO<sub>2</sub>. Mississippi Power Company's Plant Daniel, a 2,000 MW facility near the town of Escatawpa, is the site for the CO<sub>2</sub> injection test. Initial study indicates that the Massive Sand Unit of the Lower Tuscaloosa Formation could hold 11–43 billion metric tons (12–47 billion tons) of CO<sub>2</sub>, sufficient to store the CO<sub>2</sub> emissions from Plant Daniel and other power plants in the Region for decades. Deeper saline formations add considerable CO<sub>2</sub> storage capacity in this Region.



Mississippi Power Company's Plant Daniel.

### Stacked Storage Pilot Test

#### Gulf Coast Site

The Gulf Coast Stacked Storage project will demonstrate the concept of phased use of subsurface volumes, combining early use of CO<sub>2</sub> for EOR with later injection into underlying or adjacent brine formations. The benefits of this phased development are short-term, large-volume injection with immediate commercial benefit to support research and infrastructure development followed by use of underlying or adjacent brine-bearing formations for large volume, long-term storage. The Cranfield site in Southwest Mississippi has been selected for this test.

## Coal Seam Pilot Test

### Black Warrior Basin

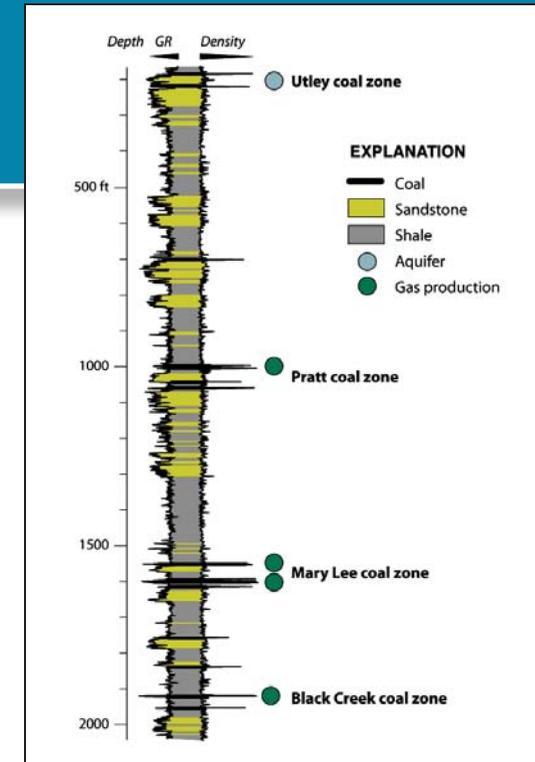
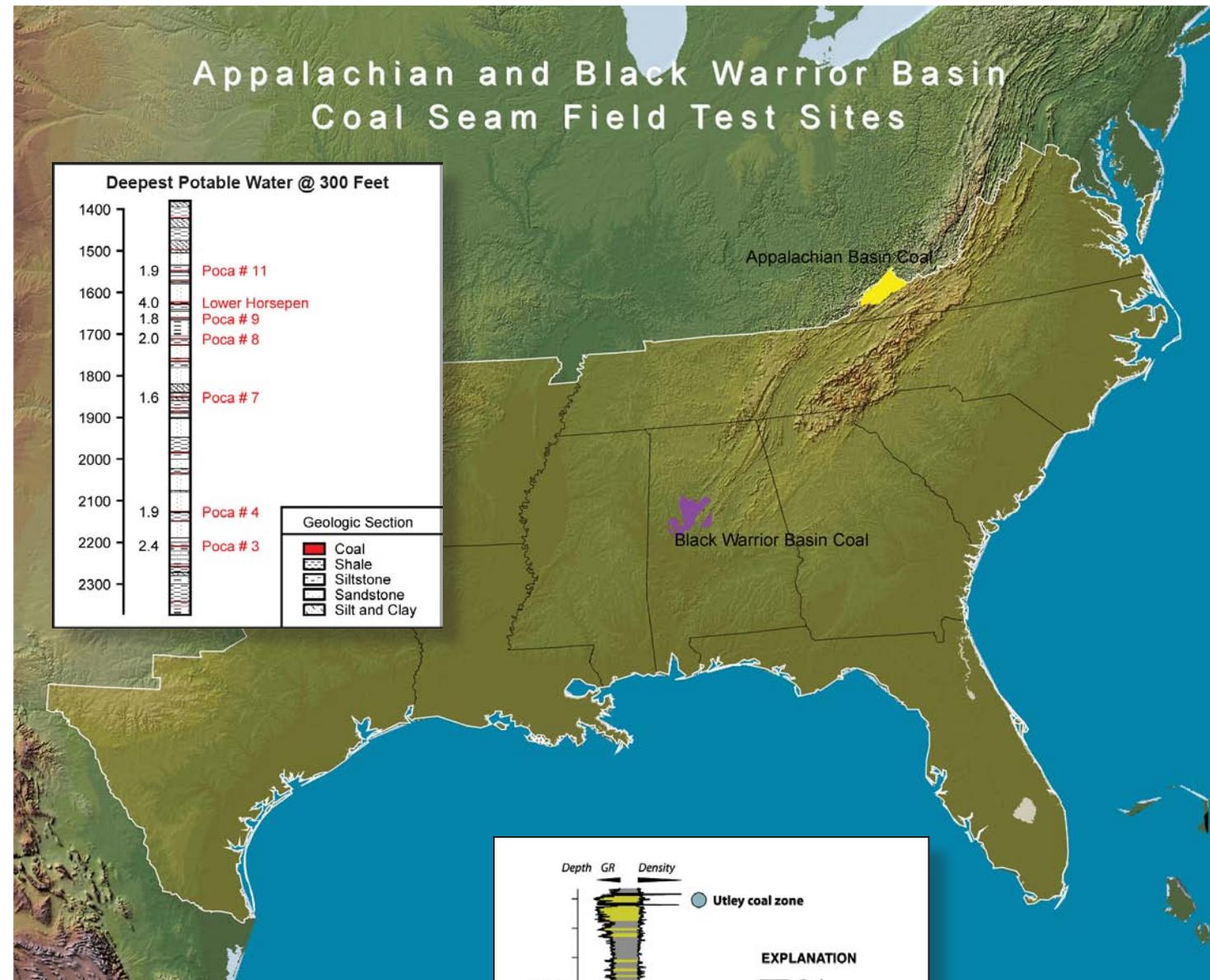
The prolific coalbed methane industry in the Black Warrior Basin is approaching maturity. Coal in the Black Warrior Basin has the potential to sequester 1,020 to 2,100 million metric tons (1,120 to 2,320 million tons) of CO<sub>2</sub>, and CO<sub>2</sub> ECBM recovery has the potential to prolong the life of the reservoirs and increase reserves by 20 to 40 percent. Two coal-fired power plants with combined CO<sub>2</sub> emissions exceeding 28 million metric tons/yr (31 million tons/yr) are located immediately to the north of the basin. The proximity of mature coalbed methane reservoirs to these plants may provide economic incentive for sequestration, depending on the cost of CO<sub>2</sub> capture from these facilities. Numerous conventional hydrocarbon reservoirs and saline reservoirs in the basin can help facilitate longer-term sequestration.



## Coal Seam Pilot Test

### Central Appalachian Basin

The most favorable areas delineated for the proposed Central Appalachian sequestration field test are located within the CBM production region in Buchanan, Dickenson, Russell, Tazewell, and Wise Counties, Virginia; and in Fayette, McDowell, Raleigh, and Wyoming Counties, West Virginia. CBM development in the area has provided extensive geologic, engineering, and production data, which will be made available for reservoir modeling. An assessment of sequestration capacity for southwestern Virginia indicates that there may be 742 million metric tons (818 million tons) of CO<sub>2</sub> storage capacity, with 279 million metric tons (308 million tons) deemed technically feasible for sequestration projects, available in the Region. The corresponding enhanced CBM recovery potential of these coals are 19–42 billion m<sup>3</sup> (0.7–1.5 trillion ft<sup>3</sup>). Sources of CO<sub>2</sub> in the area are large coal-fired power plants that may be able to supply CO<sub>2</sub> for sequestration projects.



# Southwest Regional Partnership on Carbon Sequestration

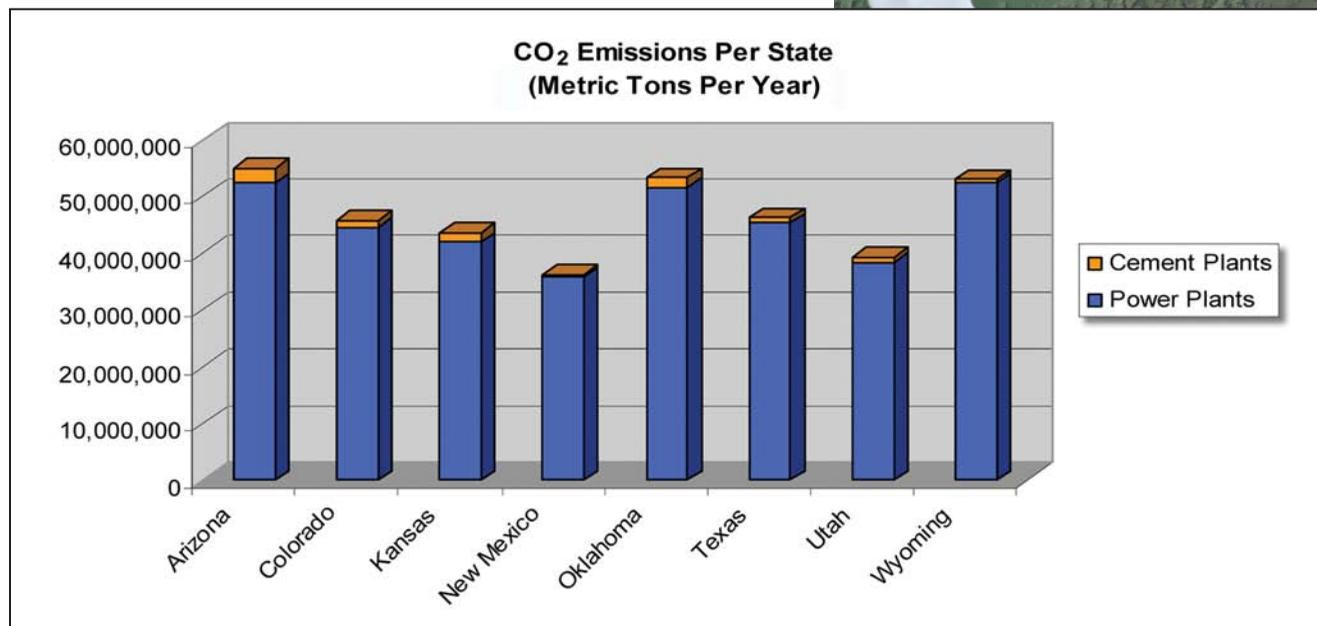
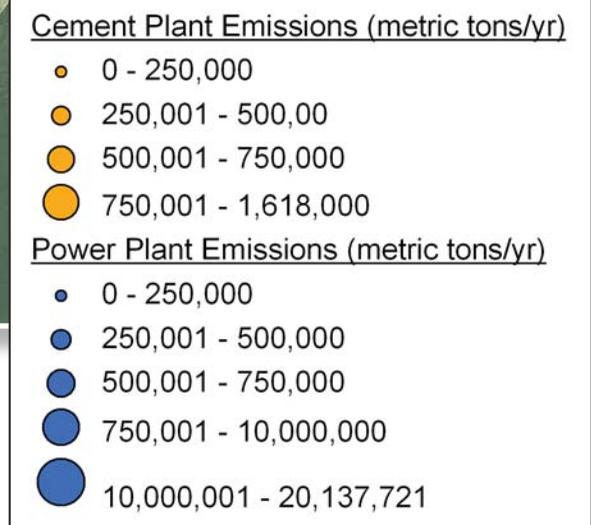
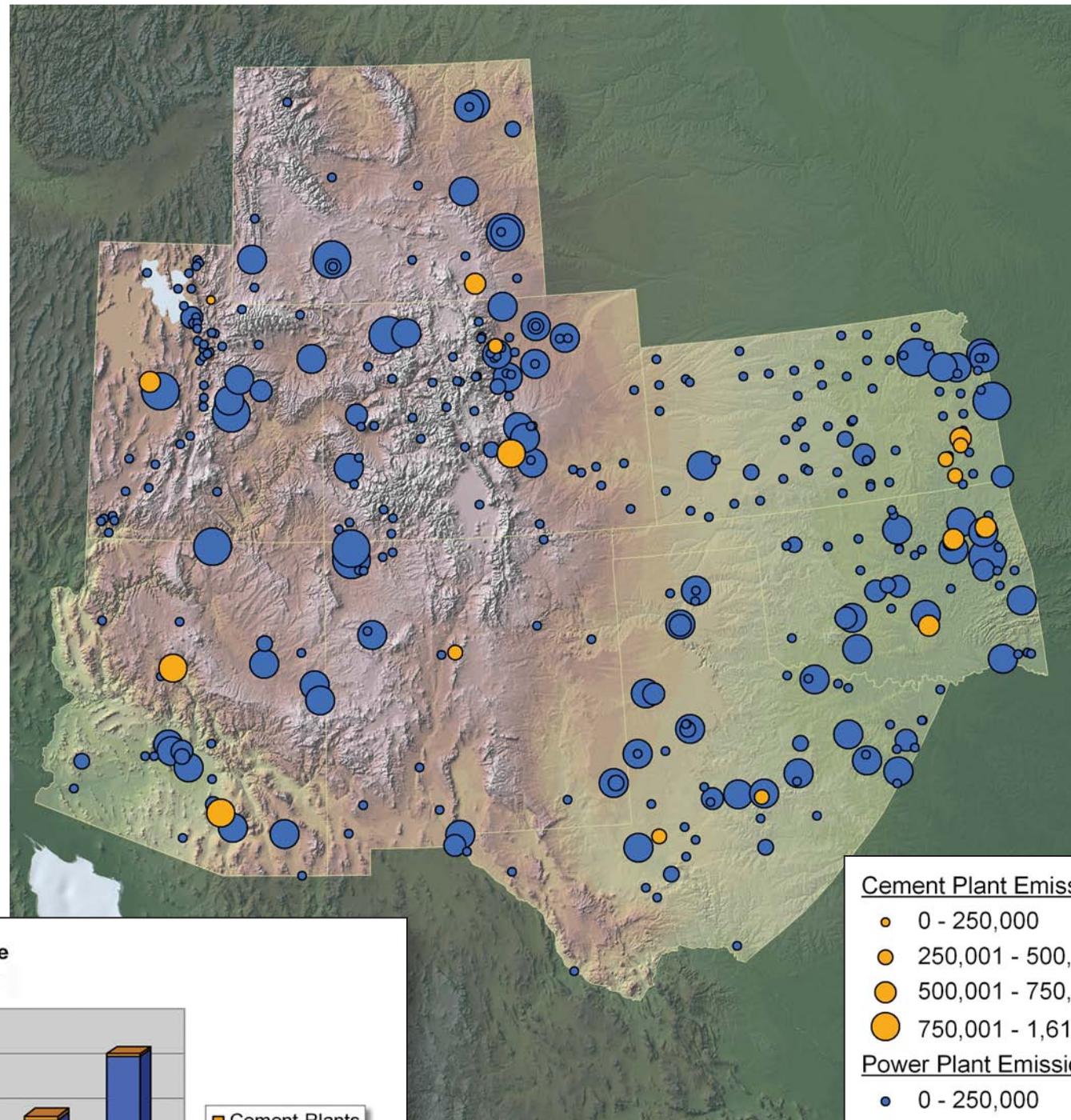
The Southwest Regional Partnership (SWP) on Carbon Sequestration was created to determine the best approaches to advance early commercial opportunities for the use of carbon sequestration—carbon capture and storage (CCS) systems. CCS has the potential to be a cost-effective option to mitigate CO<sub>2</sub> emissions. SWP is comprised of a diverse group of experts in geology, engineering, economics, public policy, and outreach. These groups are utilizing their expertise to assess sequestration technologies to capture carbon emissions, identify and evaluate appropriate storage locations, and engage a variety of stakeholders to increase awareness of carbon sequestration. Stakeholders in this project are made up of private industry, Non-government Organizations (NGOs), the general public, and government entities. A total of 21 organizations are currently represented in the partnership including electric utilities, oil and gas companies, state governments, universities, NGOs, and tribal nations.

Led by the New Mexico Institute of Mining and Technology, the SWP includes 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 Texas (Permian Basin).

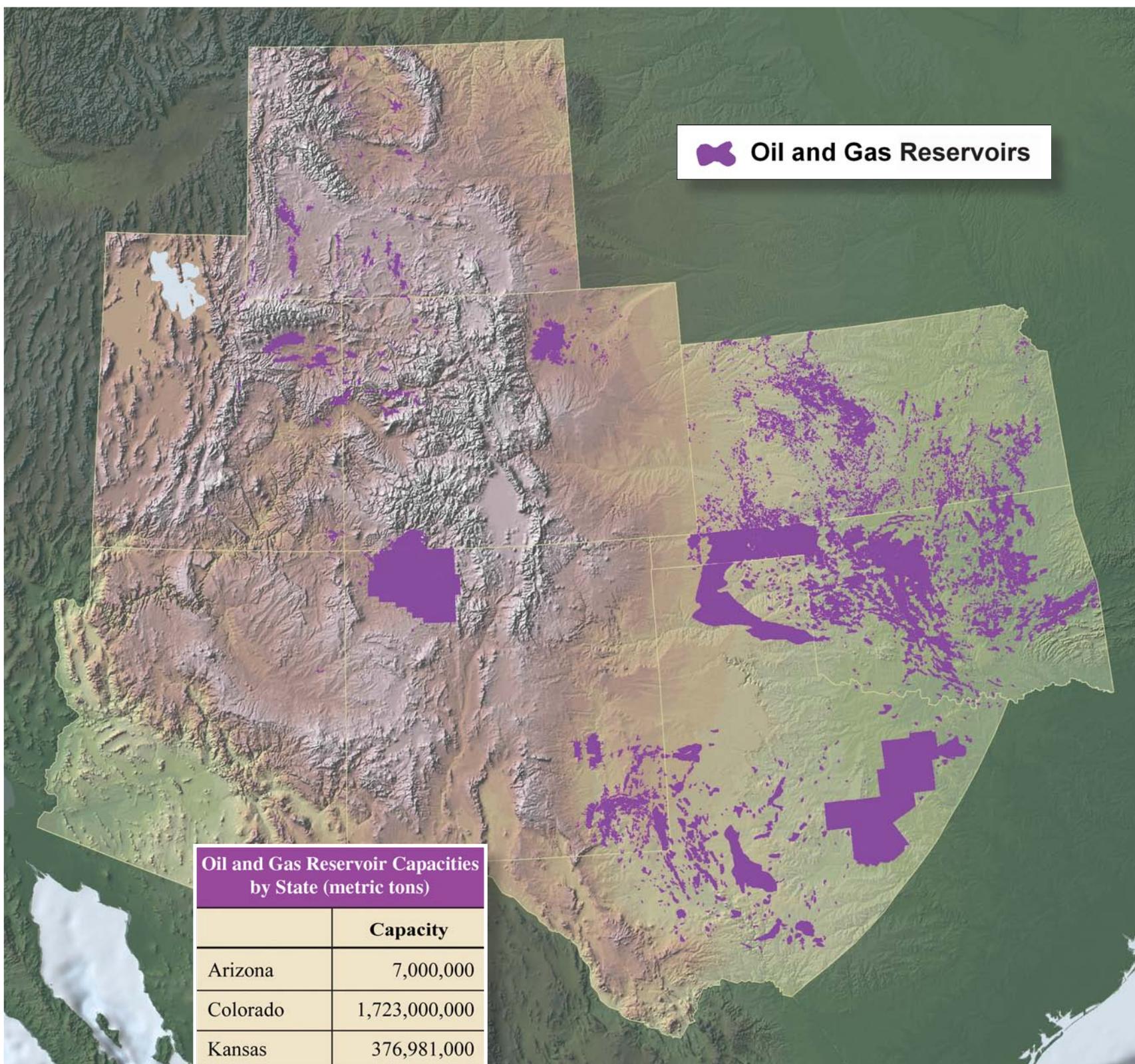


## SWP Region CO<sub>2</sub> Emission Sources

The Southwest Region is energy-rich and possesses one of the largest population and energy-production growth rates in the Nation. Two major CO<sub>2</sub> pipeline networks transport more than 27 million metric tons (30 million tons/yr) of natural, subsurface CO<sub>2</sub> from southern Colorado and northern New Mexico to petroleum fields in the Permian Basin of west Texas and eastern 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<sub>2</sub>/yr). Other stationary sources include natural gas processing plants, refineries, ammonia/fertilizer, ethylene and ethanol, and cement plants.



## SWP Oil and Gas Reservoirs



Oil and Gas Reservoir Capacities by State (metric tons)	
	Capacity
Arizona	7,000,000
Colorado	1,723,000,000
Kansas	376,981,000
New Mexico	8,246,000,000
Oklahoma	10,012,000,000
Utah	1,405,000,000

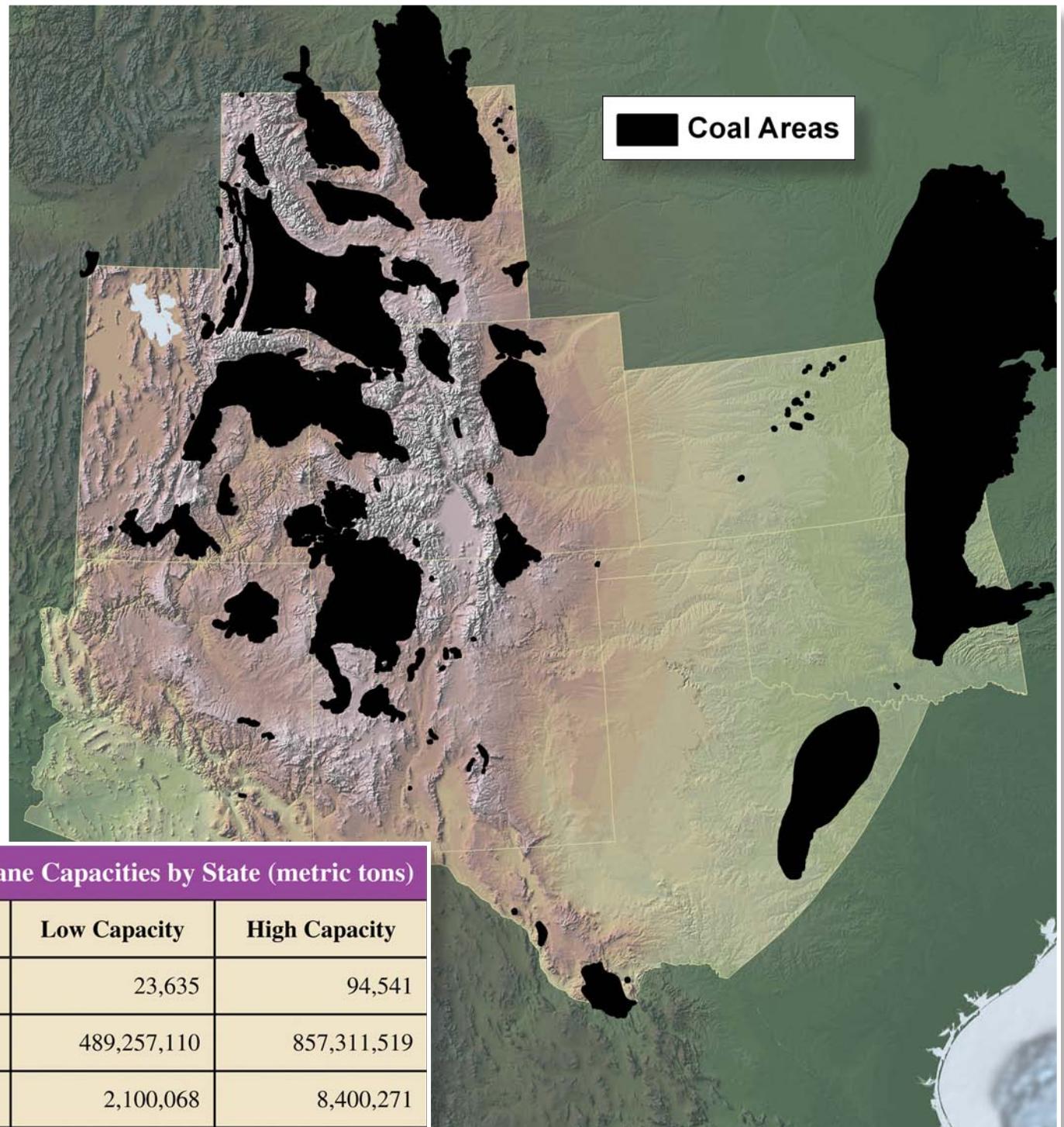
The Aneth oil field, discovered in 1956, is one of the largest in the Nation. The Aneth Unit is part of the Greater Aneth Field and is located in the Paradox Basin of southeastern Utah. The Aneth Unit is a stratigraphic trap with fractures and minor faults that cover about 68 km<sup>2</sup> (26 mi<sup>2</sup>) of the northern section of the greater Aneth Field. To date, it is estimated that about 24 million m<sup>3</sup> (149 million barrels) of an estimated 67 million m<sup>3</sup> (421 million barrels) of OOIP have been produced from the Aneth Unit. The pilot test site is located within the Aneth mound complex, which formed on a weak structural nose. The present-day structural relief of about 46 m (150 ft) is largely the result of differential compaction. The primary CO<sub>2</sub> sequestration target is the Pennsylvanian Desert Creek formation and overlying Ismay members of the Paradox formation, the primary producers in the Greater Aneth Field.

In Texas, the SACROC oil field unit and the Claytonville Canyon Lime reservoir produce oil from Pennsylvanian-age strata. The SACROC oil field unit lies along a trend of fields described as the Horseshoe Atoll Play. The Claytonville Canyon Lime reservoir lies east of SACROC in the Pennsylvanian Reef/Bank Play. This play trends north-south along the east edge of the Midland Basin and follows the paleo-Strawn and Canyon shelf edges. Target reservoirs in this unit include the producing Pennsylvanian carbonates in both fields.

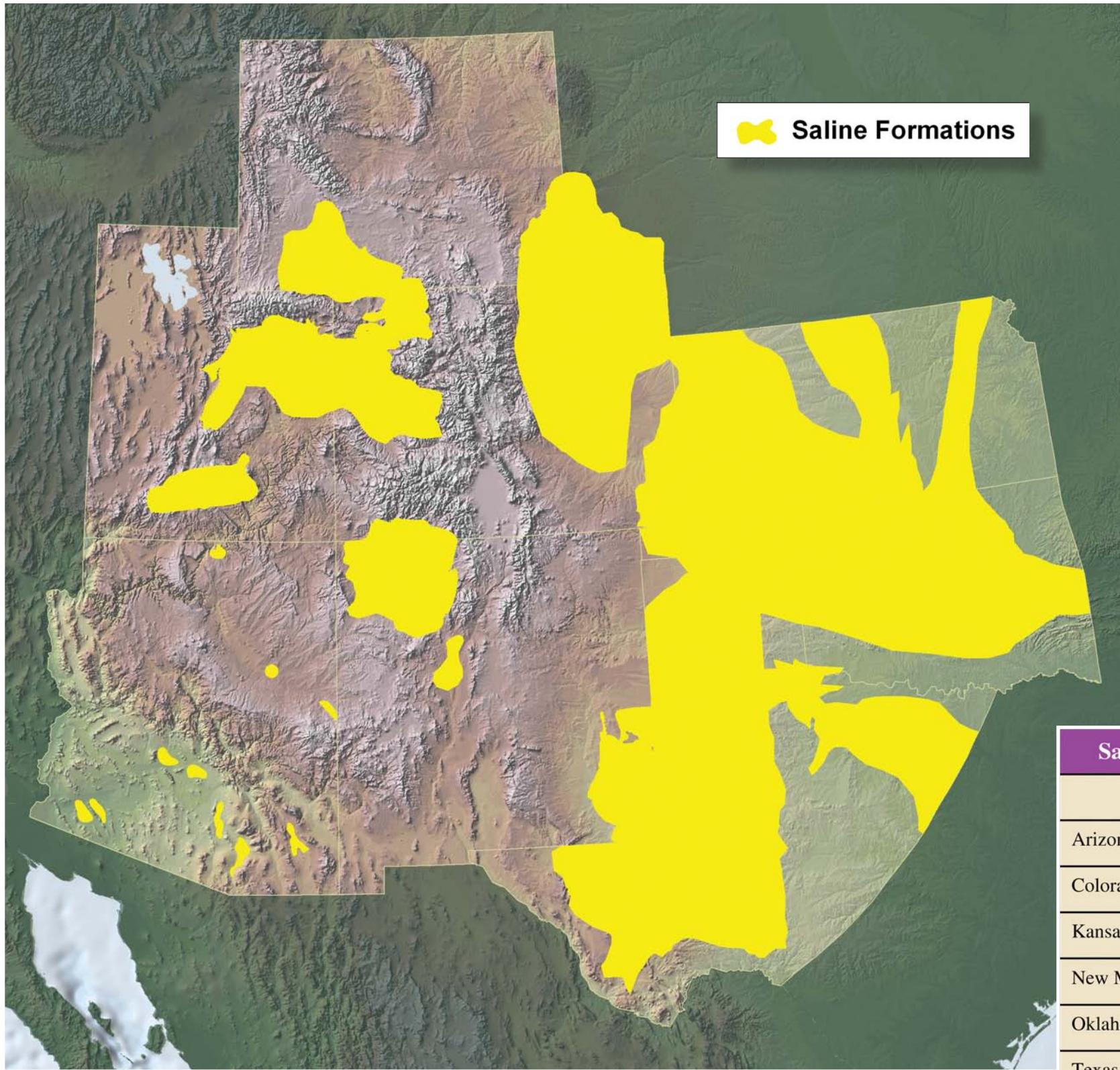
## SWP Unmineable Coal Seams

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

The coals in the SJB area are of exceptionally high permeability. Due to the tendency of coal to swell when in contact with CO<sub>2</sub>, high initial coal permeability is required to maintain high CO<sub>2</sub> injection rates over time. Maintaining high injectivity is an important requirement for large-scale, low-cost CO<sub>2</sub> sequestration in coal. Coal has a tendency to swell when injected with CO<sub>2</sub>. Since maintaining high injectivity is an important requirement, it is important to locate CO<sub>2</sub> sequestration operations in areas where coal permeability is high. The coals in the SJB formation are of exceptionally high permeability and should be well suited to ECBM.



Coalbed Methane Capacities by State (metric tons)		
	Low Capacity	High Capacity
Arizona	23,635	94,541
Colorado	489,257,110	857,311,519
Kansas	2,100,068	8,400,271
New Mexico	75,440,909	301,763,636
Oklahoma	1,845,792	7,383,169
Utah	30,514,535	122,058,139
Wyoming	194,299,134	777,196,534



## SWP Deep Saline Formations

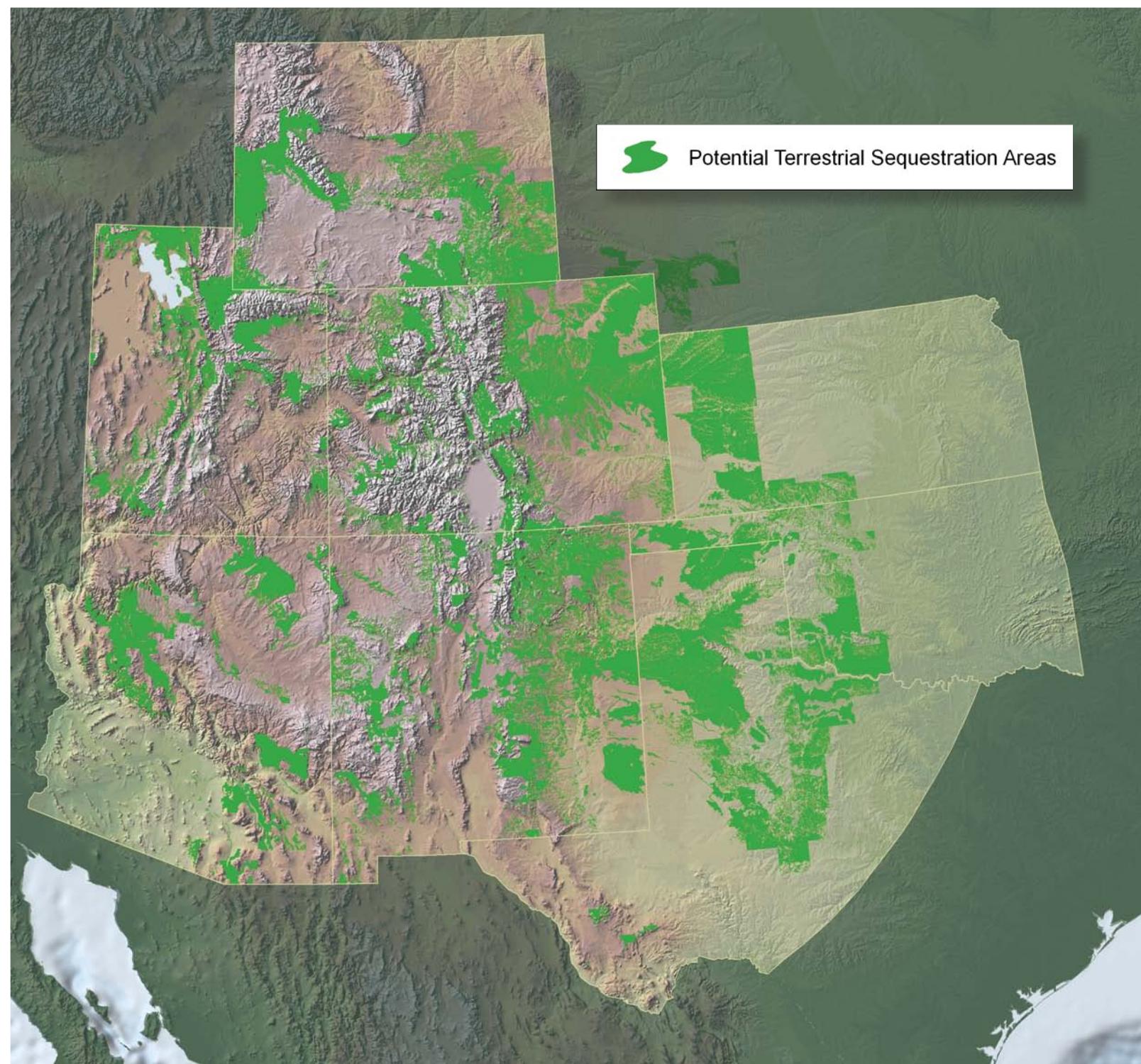
In addition to the EOR work, the Aneth Unit site includes a deep saline formation. The carbonate strata deposited on the southwestern flank of the Paradox evaporite basin are laterally equivalent to the more basinward anhydrites and salts. The Aneth Unit was originally developed with vertical wells drilled on 80-acre spacing. The field was infill drilled in the 1970s to 40 acre spacing. The field has been managed with water injection that began with unitization in the early 1960s. In 1996 Texaco drilled 43 multi-lateral horizontal wells, and in 1998, the injectors in section 14 were converted to a CO<sub>2</sub> Water Alternating Gas project to pilot the possibility of a field wide CO<sub>2</sub> injection program. Thus, monitoring of horizontal CO<sub>2</sub> injection is an added attraction offered by this pilot test site.

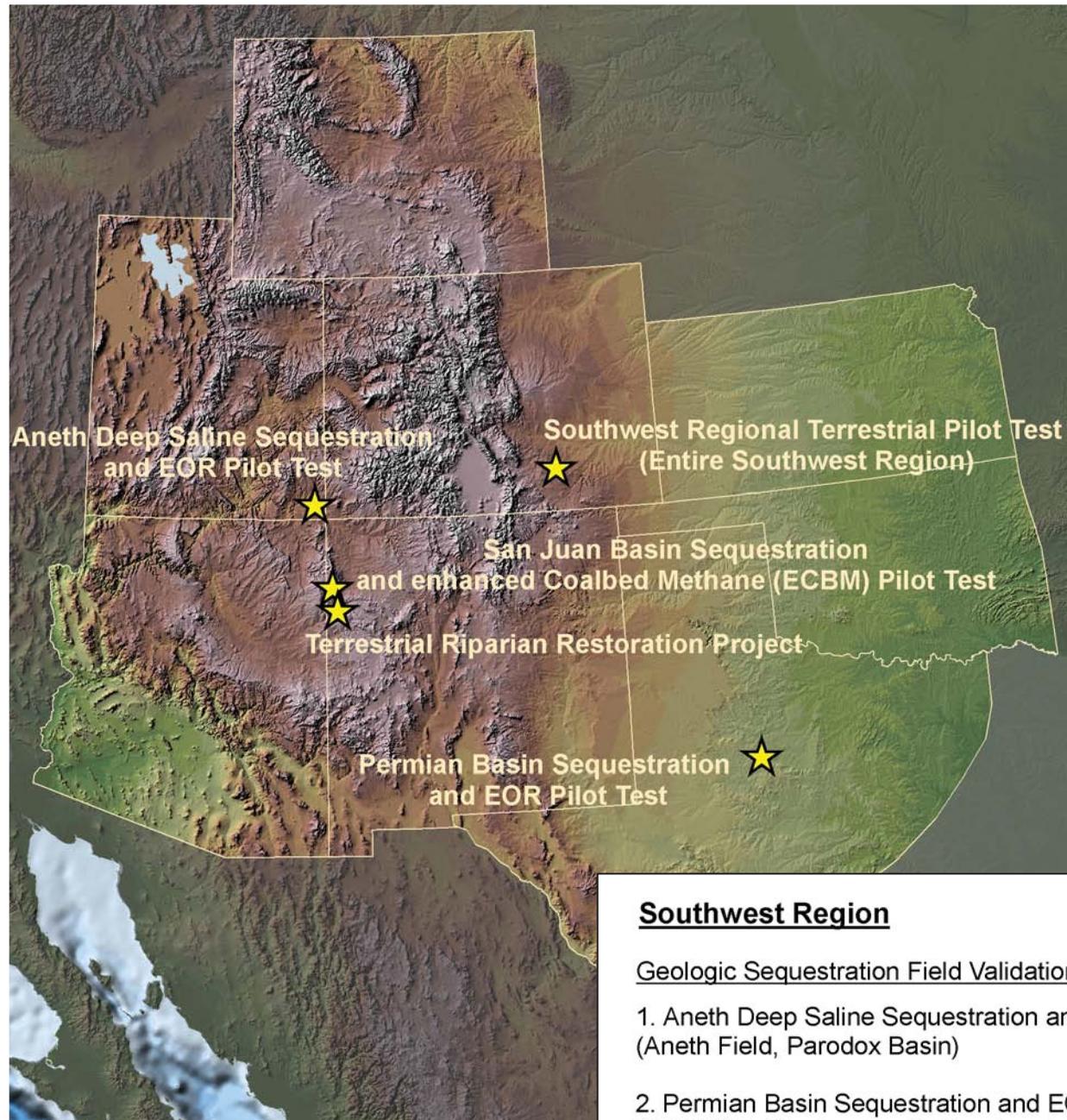
Saline Formation Capacities by State (metric tons)

	Low Capacity	High Capacity
Arizona	23,229,973	92,919,891
Colorado	972,198,156	3,888,792,622
Kansas	2,668,000,000	10,674,000,000
New Mexico	2,475,016,534	9,900,066,137
Oklahoma	2,348,363	9,396,116
Texas	11,931,102,028	47,724,408,110
Utah	127,193,409	508,773,637
Wyoming	126,922,334	507,689,335

## SWP Terrestrial Opportunities

In conjunction with the SWP's ECBM 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. The Bureau of Land Management and Burlington Resources 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 CO<sub>2</sub>, in addition to their value as recreational lands. The challenges to achieving their 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 plant growth 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 in addition to carbon sequestration.





**Southwest Region**

Geologic Sequestration Field Validations Tests

1. Aneth Deep Saline Sequestration and EOR Pilot Test (Aneth Field, Paradox Basin)
2. Permian Basin Sequestration and EOR Project (SACROC- Claytonville Fields, Permian Basin, near Snyder, TX)
3. San Juan Basin Sequestration and ECBM Pilot Test (San Juan Basin coal fairway, near Navajo City, NM)

Terrestrial Sequestration Field Validations Tests

1. Southwest Regional Terrestrial Pilot Test (Entire South West Region)
2. Terrestrial Riparian Restoration Project (San Juan Basin coal fairway, near Navajo City, NM)

**SWP Field Validation Tests**

Field sites, located in the San Juan, Paradox, and Permian Basins, are currently conducting tests on EOR, saline formation storage, ECBM, and terrestrial sequestration.

**San Juan Basin Sequestration and ECBM Pilot Test**— The SWP is conducting the San Juan Basin ECBM field validation test in cooperation with Burlington Resources. Commencing August 2007, about 68,000 metric tons (75,000 tons) of CO<sub>2</sub> will be injected over a one year period to evaluate CBM production efficiency and CO<sub>2</sub> storage optimization.

**Terrestrial Riparian Restoration Project**—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 riparian area – the interface between land and a flowing surface water body – where carbon storage will be monitored and evaluated.

**Aneth Deep Saline Formation Sequestration and EOR Pilot Test**—At the Aneth oil field near Bluff, Utah, the SWP demonstrates a combined CO<sub>2</sub> EOR and deep saline formation storage pilot on an active CO<sub>2</sub> EOR operation managed by Resolute Natural Resources Company and the Navajo Nation Oil and Gas Company. In January 2007, up to 145,000 metric tons (160,000 tons) of CO<sub>2</sub> per year over 3 years will be injected. Based on extensive geological characterization and detailed reservoir models, SWP will design MM&V protocols and conduct field studies.

**Permian Basin Sequestration and EOR Project**—The SWP is evaluating CO<sub>2</sub> EOR efficiency and CO<sub>2</sub> storage optimization at the SACROC-Claytonville field validation test, a combined EOR/CO<sub>2</sub> storage operation. In March 2008, about 159,000 metric tons (175,000 tons) of CO<sub>2</sub> per year for 1 ½ years will be injected. The geology of Aneth and SACROC-Claytonville, both carbonate reservoirs, is similar but their depth ranges vary, offering an opportunity to examine different hydrodynamic settings, which impact the flow and fate of CO<sub>2</sub> in the reservoir.

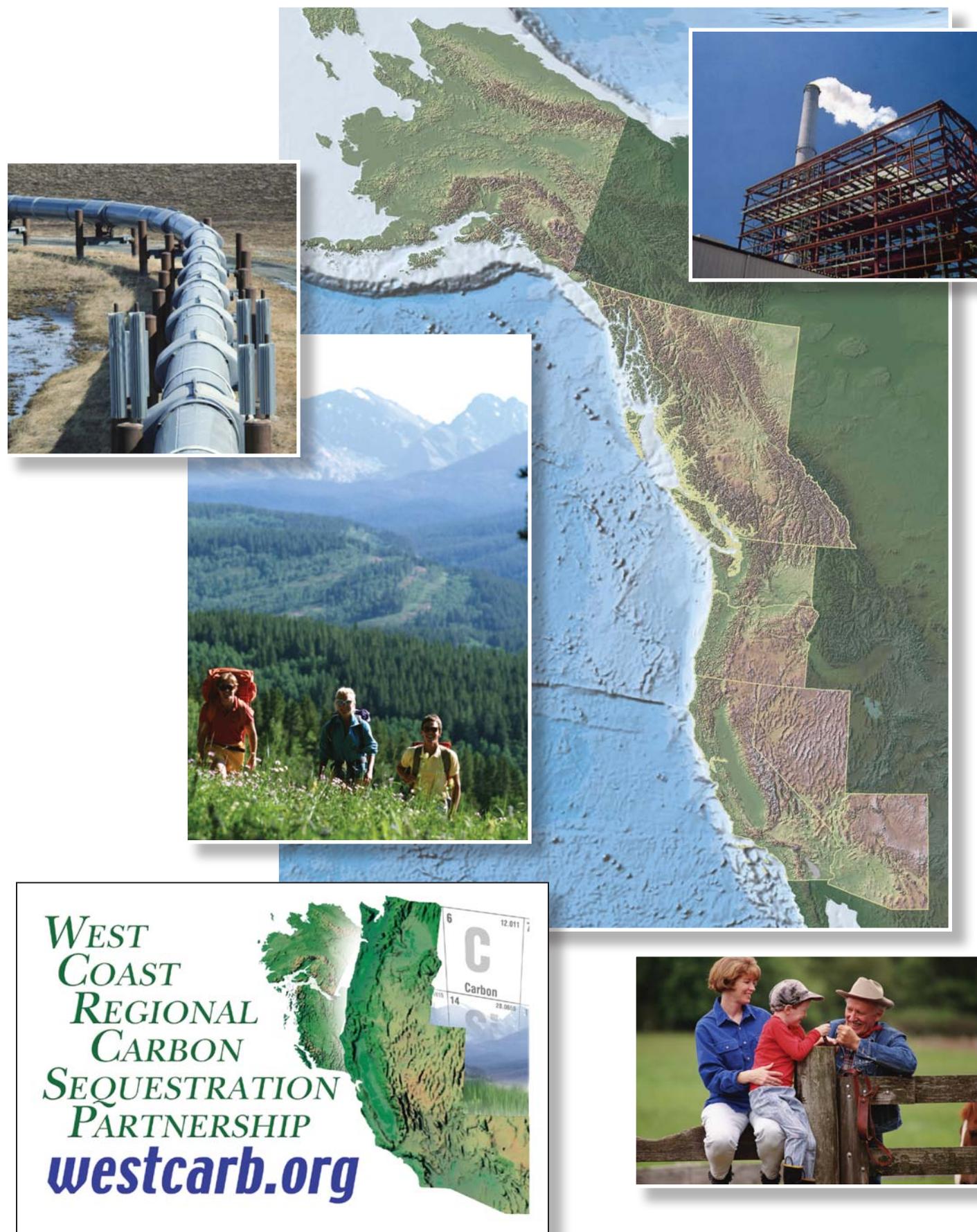
# West Coast Regional Carbon Sequestration Partnership

Western North America is characterized by picturesque natural beauty, an entrepreneurial spirit, and a large and growing population. Featuring cultural and economic diversity to match its geographic superlatives, the West Coast Region has one of North America's broadest mixes of CO<sub>2</sub> sources and an equally broad array of opportunities to curb atmospheric CO<sub>2</sub> buildup through carbon sequestration.

The West Coast Regional Carbon Sequestration Partnership (WESTCARB), led by the California Energy Commission, comprises researchers from more than 70 public agencies, private companies, and nonprofits in the U.S. and Canada. WESTCARB's goal is to identify and map the regional opportunities for geologic and terrestrial carbon sequestration. WESTCARB also seeks to validate the feasibility, safety, and efficacy of some of the best regional opportunities through pilot-scale field tests.

Results of WESTCARB characterization studies to date show excellent carbon sequestration potential throughout the Region. Numerous EOR and enhanced gas recovery opportunities, as well as ECBM, offer the potential for geologic sequestration to get an economic foothold. In addition, large, broadly distributed saline formations have the capacity to store hundreds of years of the Region's industrial emissions, if needed. Terrestrial sequestration opportunities are among the best in North America and provide a viable approach to offsetting the Region's relatively large transportation-related CO<sub>2</sub> emissions.

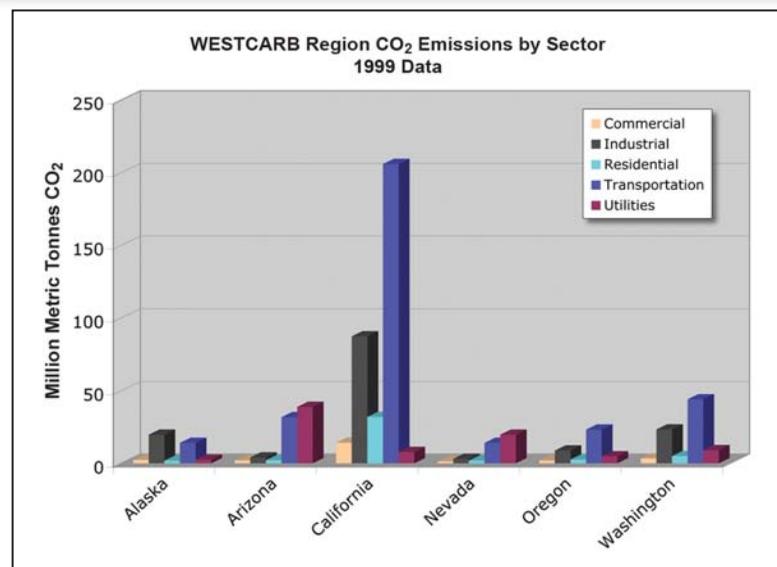
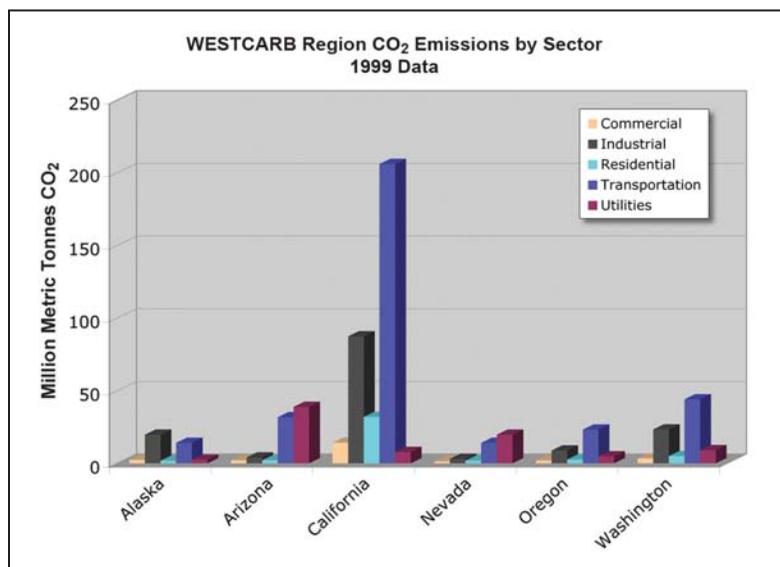
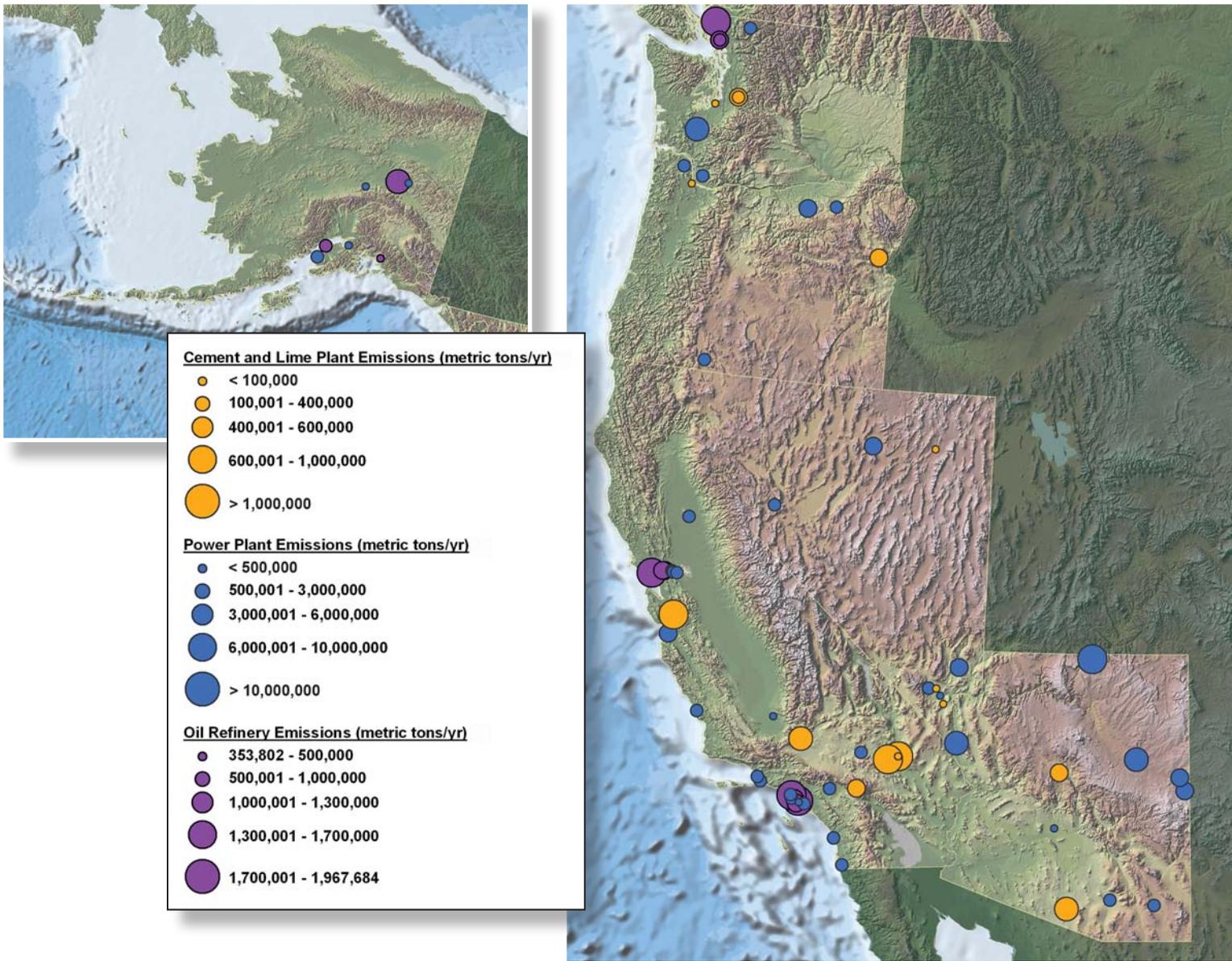
With policymakers seeking to both preserve cherished vestiges of the Old West and to lead the innovation-based 21st century economy, WESTCARB researchers feel carbon sequestration can play an important role in state and provincial efforts to address climate change issues.



## WESTCARB CO<sub>2</sub> Emission Sources

The WESTCARB Region accounts for approximately 11 percent of U.S. CO<sub>2</sub> emissions. The chart illustrating CO<sub>2</sub> emissions by sector, based on the 1999 EPA emission inventories from fuel combustion for the WESTCARB Region, shows that transportation accounts for 53 percent, and industry and utilities 36 percent of the emissions within the Region. Emissions from the transportation sector are somewhat higher than the national average, while those of the utility sector are lower. California ranks second among all states in CO<sub>2</sub> emissions, with the transportation sector accounting for the majority of the state's total. The large percentage of emissions from mobile sources is one justification for evaluating terrestrial sequestration options. The significant percentage from industrial sources motivates analysis of industrial stationary sources along with power plants in assessing geologic sequestration options. The largest stationary sources in the Region are power plants, oil refineries, and cement and lime plants.

The WESTCARB CO<sub>2</sub> sources database includes information for 77 facilities from three categories with total annual CO<sub>2</sub> large point-source emissions over 130 million metric tons (140 million tons) as seen in the chart summarizing the CO<sub>2</sub> emissions from major stationary sources in the WESTCARB Region by facility type and by state. The CO<sub>2</sub> emissions from power plants are actual 2002 CO<sub>2</sub> emissions from EPA's eGRID database, and annual CO<sub>2</sub> emissions from cement plants and oil refineries are estimates based on production capacities. Power plants are the single largest point source of CO<sub>2</sub> emissions, accounting for more than 80 percent of the emissions from the Region's largest stationary sources in the database. Arizona has the highest annual CO<sub>2</sub> large stationary source emissions in the Region, representing over one-third of the regional total emissions, followed closely by California.

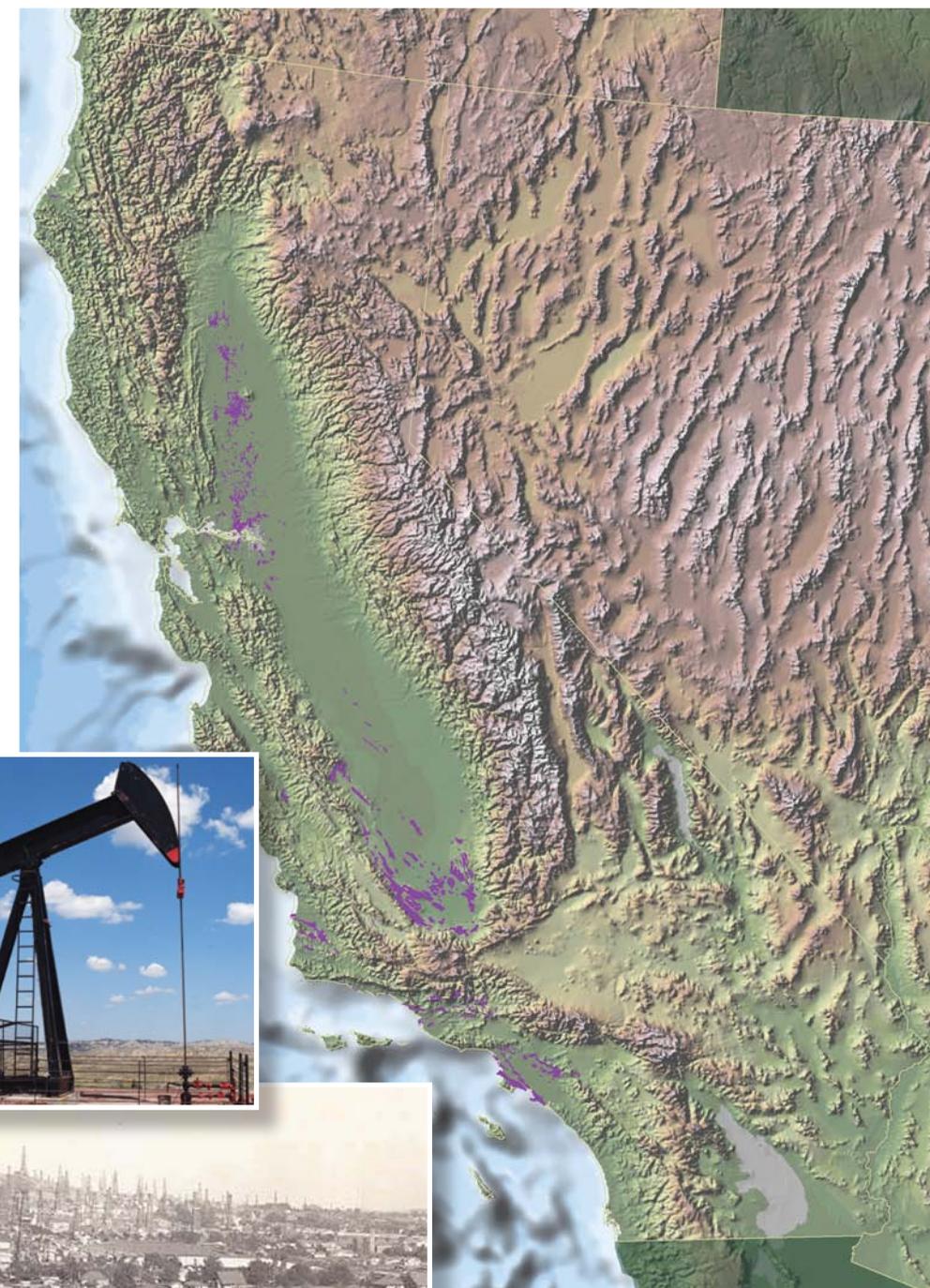


## WESTCARB Region Oil and Gas Fields

In the WESTCARB Region, major oil and gas fields represent both sequestration targets and EOR/EGR opportunities—especially in both 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<sub>2</sub> EOR storage of 3.4 billion metric tons (3.7 billion tons), based on a screening of reservoirs using depth, an American Petroleum Institute (API) gravity cutoff, and cumulative oil produced. A study of CO<sub>2</sub> EOR potential in California recently completed by Advanced Resources International concluded that technically recoverable reserves are over 0.3 million m<sup>3</sup> (5.6 billion barrels). There are abundant gas reservoirs in the Sacramento River Delta, including the Rio Vista gas field which has produced over 99 million m<sup>3</sup> (3.5 trillion ft<sup>3</sup>) of gas since the 1930s. To estimate the CO<sub>2</sub> sequestration potential in California gas reservoirs, the cumulative production from reservoirs screened by depth to assure proper storage pressure was used to find a storage capacity of 1.7 billion metric tons (1.9 billion tons).

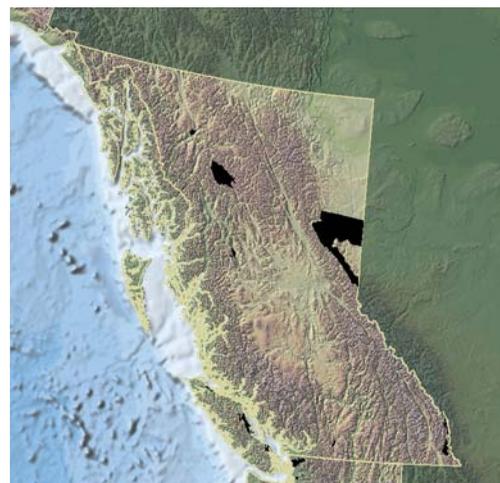
In Alaska, the oil and gas fields on the North Slope are of prime interest because of the large potential for CO<sub>2</sub> EOR. Assessment of oil and gas fields suitable for CO<sub>2</sub> sequestration in Alaska and Nevada are ongoing.



 Oil And Gas Formations



*This historical photograph of Signal Hill in Long Beach, California, dates from 1923, when wells were drilled on townlots. At that time, approximately 41,000 m<sup>3</sup> (260,000 barrels) of crude oil was produced daily from about 300 wells, making Signal Hill the most productive field per acre worldwide, and making California the nation's top oil-producing state. Signal Hill may take on new historical significance in the 21st century as a site for geologic CO<sub>2</sub> storage.*



 Coal Basins

## WESTCARB Coal Basins

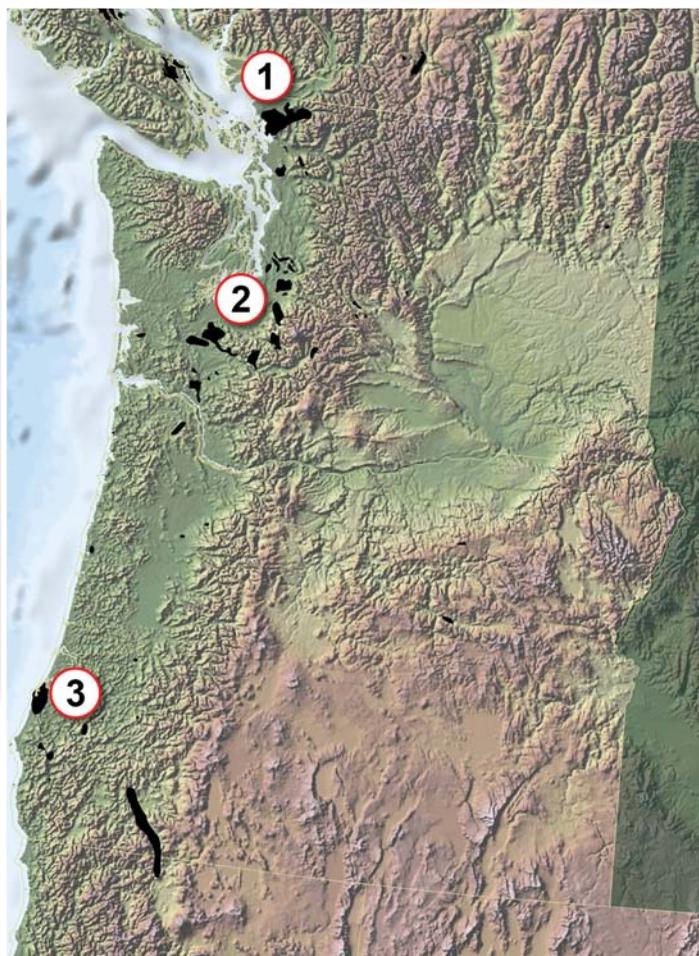
Opportunities for geologic CO<sub>2</sub> storage in coal basins within the WESTCARB Region are found predominantly in the Pacific Northwest and Alaska. In the Pacific Northwest, three deep coal bed locations offer promise: (1) the Bellingham Basin in northwestern Washington; (2) the coals of the upper Puget Sound Region, south and east of the Seattle-Tacoma metropolitan area; and (3) small, deep coal deposits in southwestern Oregon.

Puget Sound coals have been extensively tested by CBM exploration companies and WESTCARB investigators are characterizing their CO<sub>2</sub> sequestration potential. Preliminary results show the subsurface extent of the coal basins in an area of greater than 2,500 km<sup>2</sup> (950 mi<sup>2</sup>). Initial analysis indicates prospective coal seam reservoir properties of 30 m (100 ft) coal thickness, a CO<sub>2</sub> sorption capacity of 20–24 m<sup>3</sup> (700–850 ft<sup>3</sup>) CO<sub>2</sub> per ton coal, and approximately 5 millidarcies permeability. The Puget Region offers encouraging prospects for testing CO<sub>2</sub> storage in unmineable coal seams. The estimated CO<sub>2</sub> 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<sup>3</sup> (2–20 trillion ft<sup>3</sup>).

Although coal mining in Alaska has been very limited, the state contains major coal deposits that range from shallow deposits to deposits over 2,000 m (6,500 ft) deep. Three major geologic provinces account for nearly 90 percent of Alaska's coal resources: (a) the North Slope Region in Northern Alaska, (b) the Nenana Region in Central Alaska, and (c) the Cook Inlet Region in Southern Alaska. Most estimates of coal resources date back to the early 1980s and tend to be biased towards shallow, mineable coal deposits, and frequently do not consider coals encountered in deep oil and gas wells that are prime targets for CBM development and CO<sub>2</sub> storage. Preliminary estimates of geologic CO<sub>2</sub> storage capacity in Alaska suggest that 84 billion metric tons of CO<sub>2</sub> could be stored in deep coal seams. Alaska's methane resources are estimated to be approximately 22 trillion m<sup>3</sup> (776 trillion ft<sup>3</sup>), which is comparable to CBM resources in all of the lower 48 U.S. states. Essentially all of the CO<sub>2</sub> storage potential and CBM potential is located in the North Slope and Cook Inlet regions, which have thick coals of suitable thickness, depth, rank, and quality. It is likely that only a portion of the 84 billion metric tons (93 billion tons) would be considered favorable for CO<sub>2</sub> 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 develop more rigorous estimates as studies progress.



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



## WESTCARB Saline Formations

Sedimentary basins containing saline formations are broadly distributed throughout the WESTCARB Region.

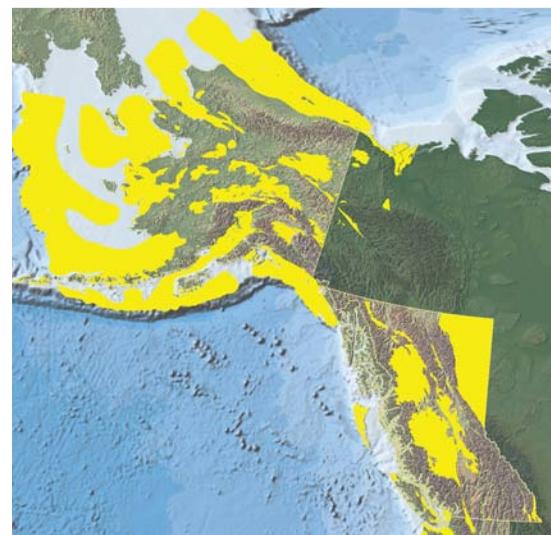
Initial WESTCARB assessments indicate that California's Cenozoic marine sedimentary possess the most potential for geologic sequestration. As a group, these basins exhibit a wide areal distribution, thick sedimentary sections containing multiple widespread saline-saturated sandstones, thick and laterally persistent shale seals, and petrophysical data available through oil and gas development. The most promising basins include the San Joaquin, Sacramento, Ventura, Los Angeles, and Eel River basins. Smaller marine basins, including the Salinas, La Honda, Cuyama, Livermore, Orinda, and Sonoma basins, are also promising but more restricted in terms of size and available geological information. The total storage capacity of the 10 most promising basins is approximately 75–300 billion metric tons (83–330 billion tons) CO<sub>2</sub>. Most of California's nonmarine basins are too shallow for carbon sequestration, however, the large Salton Trough and several smaller nonmarine basins may offer some opportunities.

In Oregon and Washington, western coastal basins offer potential sequestration opportunities. These basins are associated with a major Tertiary sedimentary belt of basins formed in a regional fore-arc environment. Promising basins include the Puget Trough, Tofina-Fuca Basin, West Olympic Basin, Whatcom Basin, and Willapa Hills Basin in Washington, and the Astoria-Nehalem Basin and Tyee-Umpqua Basin in Oregon. These basins contain sandstone/shale sequences that are up to 9,000 m (30,000 feet) thick. The total storage capacity for all 7 of these sedimentary basins is approximately 20–85 billion metric tons (22–94 billion tons) of CO<sub>2</sub>.

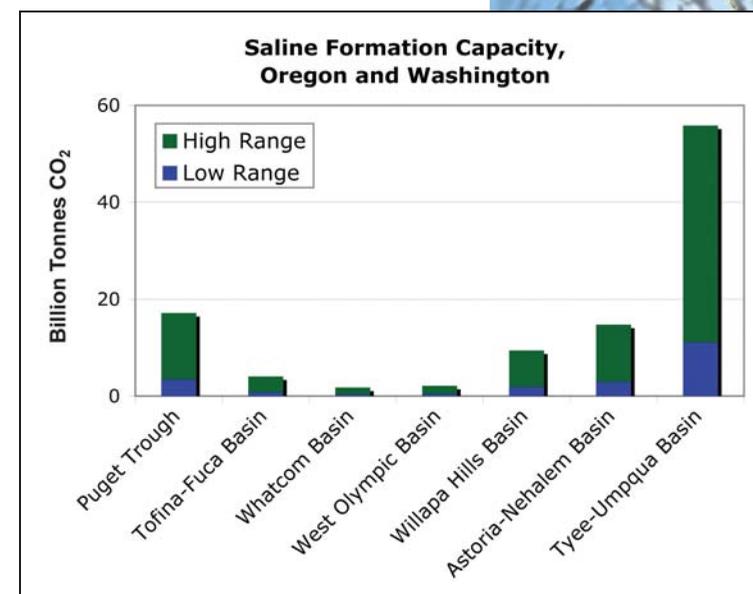
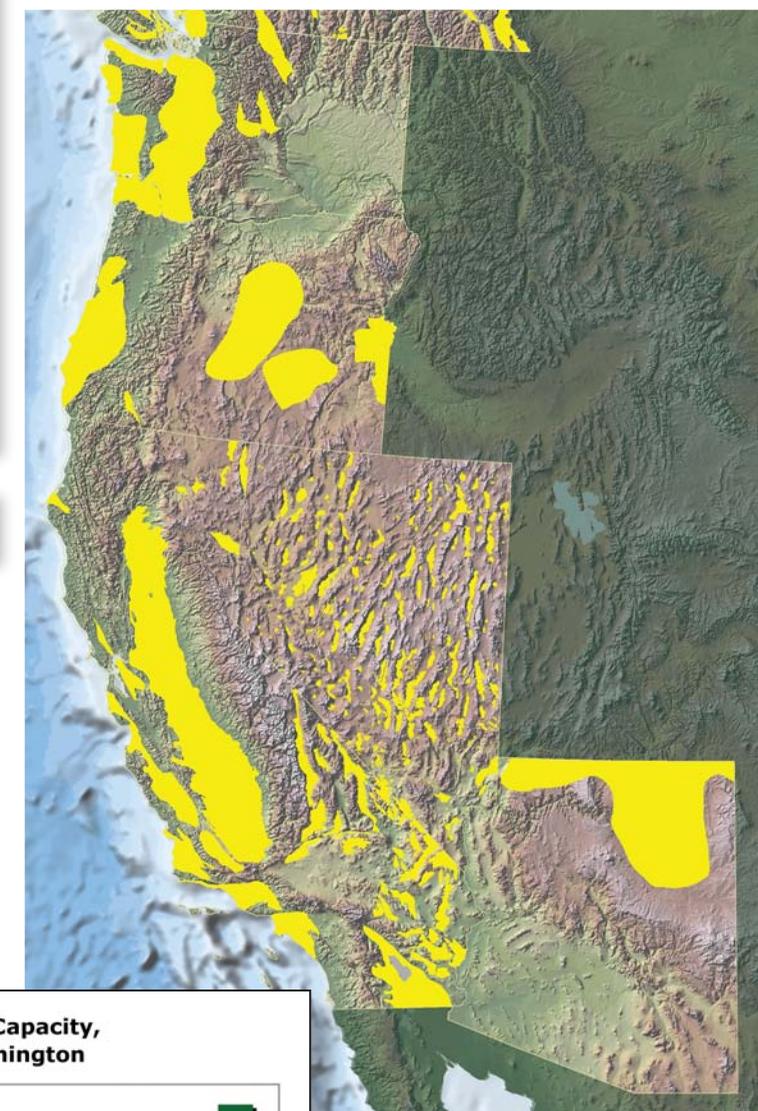
Although basins east of the Cascade Mountains have characteristics that are favorable for potential sequestration, very few data are available to characterize their potential.

In Alaska, six basins contain sediments of sufficient thickness to be considered as potential sequestration targets.

Finally, in Arizona, sediments underlying the Colorado Plateau represent the initial target for sequestration opportunities. The primary storage targets are the Naco Formation, Martin Formation, Coconino Sandstone, and the Schnebly Hill Formation. Potential reservoir seals include the Supai Formation, Chinle Formation, and the Moenkopi Formation. Both the potential storage targets and potential seals are laterally extensive and up to hundreds of feet thick.



 Deep Saline Formations



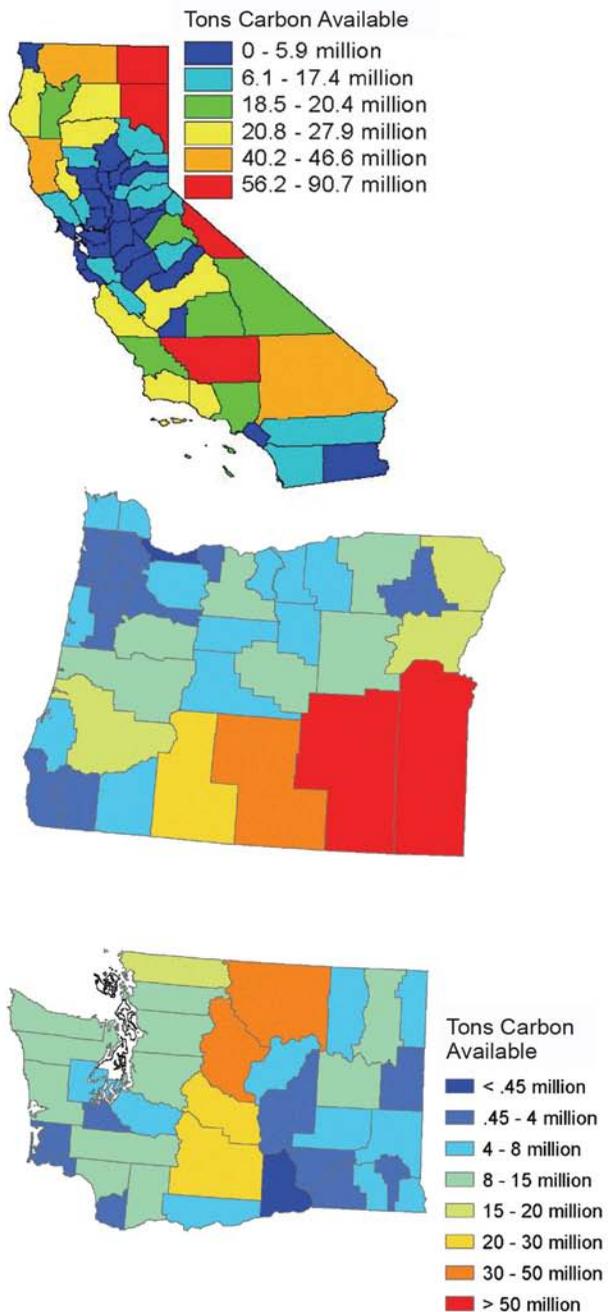
## WESTCARB Terrestrial Sequestration Opportunities

Terrestrial carbon sequestration opportunities analyzed for the WESTCARB Region included afforestation of rangelands and agricultural lands, changes in forest management to increase carbon stocks, and improved management of forest fuels to reduce GHG emissions from wildfires, and the use of these fuels in biomass energy facilities.

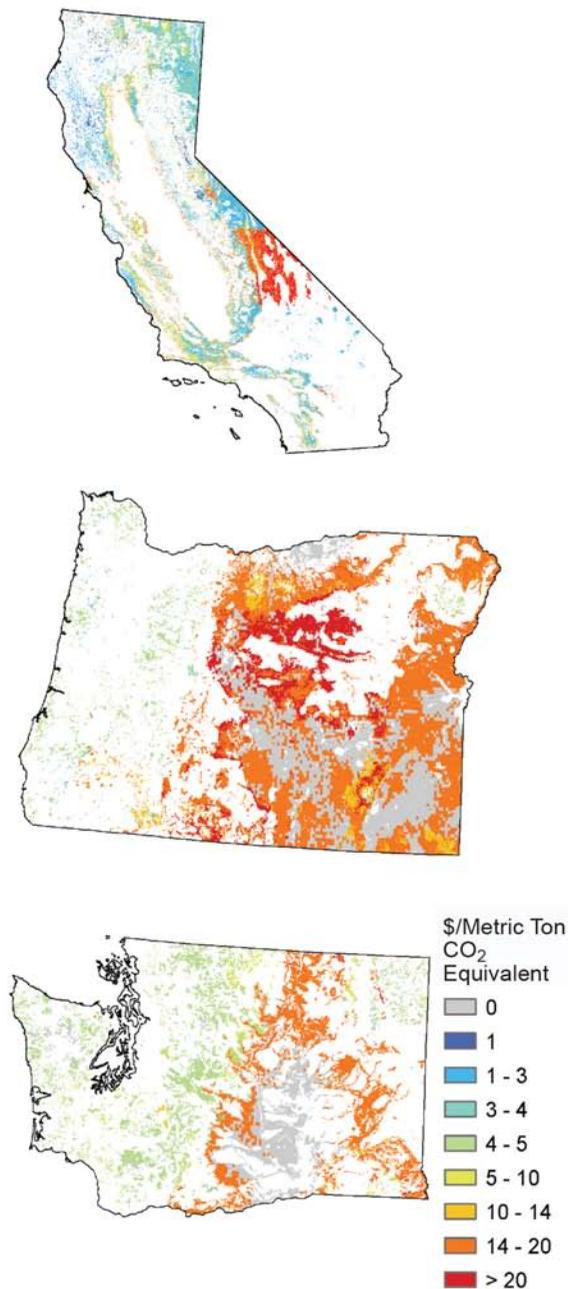
Afforestation of rangelands was examined for California, Oregon, and Washington on 20-, 40-, and 80-year time periods, including analysis of forest suitability of candidate lands; total costs including opportunity, conversion, maintenance, measurement, and monitoring costs; potential rates of carbon sequestration; and at different prices per metric ton CO<sub>2</sub>, the total area and geographic distribution of lands that might be afforested and quantity of carbon thus sequestered.

On agricultural lands, afforestation was analyzed for 20-, 40-, and 80-year projects on hay and wheat lands in Oregon and Washington, and conservation tillage was analyzed for California. Forest management options included 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 cutting, skidding, chipping, and hauling fuels from wildfire-prone forests to biomass energy plants, including suitability of lands for fuel reduction, treatable area, and biomass yield under typical treatment constraints.

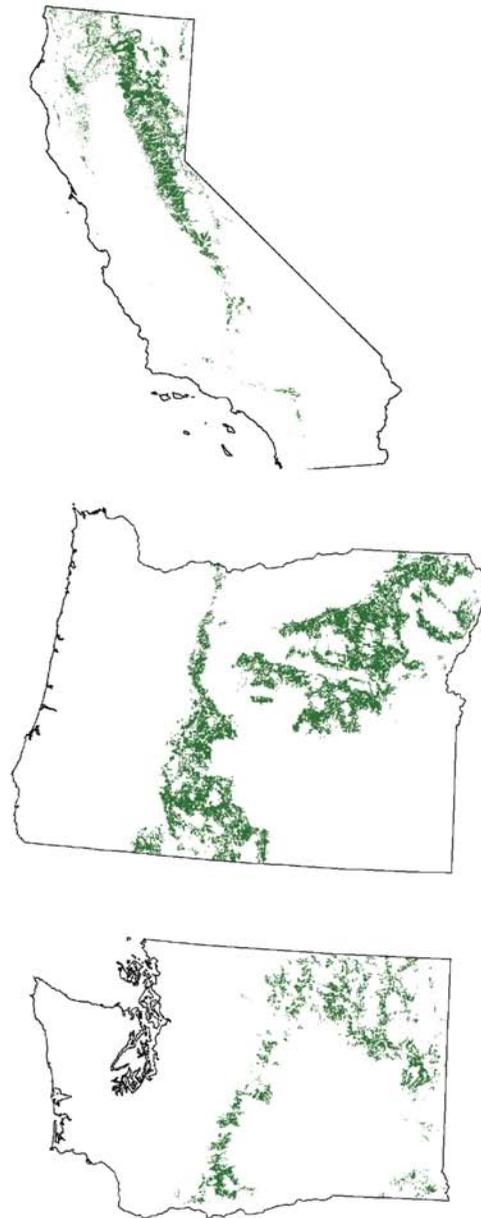
Potential Sequestration Through  
Afforestation After 40 Years



Marginal Cost After 40 Years of Sequestering  
Carbon by Afforestation \$ Per Metric Ton Carbon



Forest Lands Suitable for  
Biomass Fuel Production



## WESTCARB Field Validation Tests

WESTCARB will perform three geologic sequestration pilot tests, two terrestrial sequestration pilot tests, and two CO<sub>2</sub> storage investigations within its region.

Two geologic CO<sub>2</sub> sequestration pilot tests, collectively referred to as the Rosetta Resources CO<sub>2</sub> Storage Project, will be performed in the southern part of the Sacramento River Basin in the Central Valley of California. The Central Valley, composed of the Sacramento River Basin in the north and the San Joaquin River Basin in the south, contains numerous saline formations and oil and gas reservoirs that could be used for geologic storage of CO<sub>2</sub>. These Central Valley saline formations are estimated to have a storage capacity of 50–200 billion metric tons (55–220 billion tons) of CO<sub>2</sub>, representing a potential reservoir of thousands of years of emissions within the southern Sacramento River Basin near the proposed pilot site. The first pilot test will inject up to 1,000 metric tons (1,100 tons) of CO<sub>2</sub> into a saline formation below the Thornton Gas Field. The second test will inject about 500 metric tons (550 tons) of CO<sub>2</sub> into a depleting compartment of the Thornton Gas Field and assess the extent to which gas recovery can be enhanced due to reservoir pressurization and displacement of methane by CO<sub>2</sub>.

The Northern Arizona Saline Formation pilot will investigate CO<sub>2</sub> storage in saline formations in the Colorado Plateau Region in northern Arizona. The occurrence of natural CO<sub>2</sub> accumulations in the Colorado Plateau attests to its potential to store CO<sub>2</sub>. Storage capacity within the basin is estimated to be large because of the thickness—more than 100 m (330 ft)—of the potential storage formations and the presence of good seals. Although less studied than California’s Central Valley, available well data suggest suitable saline and seal formations may be found in the vicinity of the state’s coal-fired power plants. Proximity to these large sources of CO<sub>2</sub> could establish much of the infrastructure needed for a future “integrated” project involving both CO<sub>2</sub> capture and sequestration.

Terrestrial carbon sequestration pilots are initially taking place in Shasta County, California, and Lake County, Oregon. Opportunities for future terrestrial pilots in Washington and Arizona are also being identified. Pilot activities include afforestation (in Shasta County, of rangelands), improved management of forest fuels to reduce emissions from wildfires (and potentially fuel biomass power plants), and conservation-based forest management. Overall objectives are to quantify 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 capture verifiable reductions at reasonable cost to landowners and carbon credit buyers; explore questions of market validation for terrestrial activities; and evaluate environmental co-benefits.



### WESTCARB Region

#### Geologic Sequestration Field Validations Tests

1. Rosetta Resources Saline Formation CO<sub>2</sub> Storage Pilot (Near Rio Vista, CA. North Central Valley)
2. Rosetta Resources Gas Reservoir CO<sub>2</sub> Storage Pilot (Near Rio Vista, CA. North Central Valley)
3. Northern Arizona Saline Formation CO<sub>2</sub> Storage Pilot (Northeast Arizona, Kaiparowits Basin)
4. Kimberlina Saline Formation and Oil Field CO<sub>2</sub> Storage Investigation (Kimberlina CA. South Central Valley)
5. Centralia Geologic Formation CO<sub>2</sub> Storage Investigation (Centralia, WA. Puget Sound Basin)

#### Terrestrial Sequestration Field Validations Tests

1. Shasta County (CA) Terrestrial Sequestration Pilot
2. Lake County (OR) Terrestrial Sequestration Pilot



# Methodology for Development of Carbon Sequestration Capacity Estimates

## APPENDIX A

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### 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

**December 2006**

## Foreword

This document describes the methodologies that were used to produce the capacity estimates for the *2006 Carbon Sequestration Atlas for the United States and Canada*. The rationales presented were used to simplify assumptions for estimating the amount of carbon dioxide (CO<sub>2</sub>) that can be stored in subsurface geologic environments of the onshore United States on a formation-by-formation or basin-by-basin basis.

The Regional Carbon Sequestration Partnerships (RCSPs) were charged with providing a quantitative assessment of the volume of CO<sub>2</sub> storage potential available in the subsurface environments of their Regions. These volumes are required to indicate the extent to which carbon capture and storage (CCS) technologies could contribute to the reduction of CO<sub>2</sub> 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 are designed to integrate results of data completed by the seven RCSPs for three types of geological formations: saline formations, unmineable coal seams, and hydrocarbon (oil and gas) formations. These methodologies were developed to be consistent across North America for a wide range of data. Results of this assessment are intended to be distributed by a geographic information system (GIS) and available as hard-copy results in the *2006 Carbon Sequestration Atlas for the United States and Canada*.

This document is a consensus product resulting from discussions among researchers representing all seven RCSPs. A subcommittee on Capacity Assessment convened by the Geologic Working Group of the RCSP in May of 2006 provided leadership for this effort. Methods used by the RCSP for estimating CO<sub>2</sub> storage capacity were inventoried, and methods in the literature were reviewed (Holloway and others, 1996; Brennan and Burruss, 2003; Carr and others, 2003; Bradshaw and others, 2006; Obdam, 2006). A workshop in Kansas July 11–12, 2006, provided a venue for broader discussion within the Geologic Working Group and GIS working groups, and additional discussion has occurred via phone conference and e-mail, leading to development of consensus on the approach presented here.

# Contents

<b>74</b>	<b>Introduction</b>
<b>74</b>	<b>Approach</b>
<b>74</b>	<b>Limits</b>
<b>74</b>	<b>Reporting</b>
<b>75</b>	<b>Types of Geologic Environments</b>
	– Saline Formations
	– Oil and Gas Reservoirs
	– Coal Beds
<b>78</b>	<b>Data Density and Uncertainty</b>
<b>78</b>	<b>References</b>
<b>79</b>	<b>Appendices</b>
	– Appendix 1. Estimation of the Storage Efficiency Factor for Saline Formations (prepared by Scott Frailey)
	– Appendix 2. Estimation of the Storage Efficiency Factor for Unmineable Coal Seams (prepared by Scott Frailey)
	– Appendix 3. Comparison of Pore Volume Occupied by CO <sub>2</sub> Dissolution in Saline and Free Phase CO <sub>2</sub> (prepared by Scott Frailey)
	– Appendix 4. Comparison of CO <sub>2</sub> Storage Estimates in Oil Formations Using Production and Volumetrics (prepared by Scott Frailey)

## Introduction

Geologic carbon storage capacity is an estimate of the maximum amount of carbon dioxide (CO<sub>2</sub>) that can be stored in geologic formations. The methodologies used to estimate geologic carbon storage capacities for this 2006 assessment consist of widely accepted assumptions about geologic storage mechanisms. Data collected by the Regional Carbon Sequestration Partnerships (RCSPs) during the first 3 years of the RCSP Initiative were used, along with these methodologies, to estimate geologic storage capacities. Diverse data from three types of geologic formations (saline formations, coal seams, and hydrocarbon formations) in the subsurface were summarized, interpolated, averaged, or generalized to calculate storage capacities on a subregional (formation or basin) scale by each of the seven RCSPs. Storage capacity methodologies for shale and basalt formations are currently under development.

Capacity estimates produced using these methodologies were unencumbered capacities, meaning that nongeologic factors that may limit the amount of CO<sub>2</sub> stored, such as cost of capture and transport or incompatible surface land uses.

## Approach

The approach used to determine these methodologies was to (1) quantify at a subregional scale the storage resource (pore volume or adsorptive space) available (suitable saline, hydrocarbon, coal volumes) and (2) apply an estimate of the efficiency at which this resource can be used for storage of CO<sub>2</sub>. Storage efficiency (E) represents a percentage of saline and coal resources that can be used for storage in all formations throughout the United States. Monte Carlo simulations, including ranges of uncertainty, were used to generate a low- and a high-efficiency estimate, which results in estimation of a low and a high value of capacity (Appendices 1 and 2). For hydrocarbon (oil or gas) formations, a single value of capacity was calculated because these storage volumes are well understood in comparison with other formation types. Any equivalent efficiency needed for each formation or group of formations was developed by each RCSP. Appendices 3 and 4 discuss standardization among types of data that were available for different regions.

## Limits

The purpose of capacity estimates developed using these methodologies is to provide a high-level inventory of the capacity of the subsurface to store CO<sub>2</sub> in the United States and Canada. This information can be used by the general public, elected officials, and planners. These methodologies are not designed to support site-specific decisions, such as location of injection wells. Site-specific capacity per unit volume of the subsurface could be either higher or lower than the average per-unit volume storage in the Region assessed.

This assessment is not intended for highly quantitative cross-comparison of the capacity of each type of storage formation (for example, saline vs. oil and gas vs. coal) because in some

cases the volumes are not separated (in some areas oil and gas formation and coal formation volume estimates are summarized collectively within saline formation storage estimates). In addition, the efficiencies assigned have not been normalized against each other to support a rigorous comparison. Cross-comparison of the capacity of each type of storage formation will become more quantitative as capacity is field-tested.

It is anticipated that capacity estimates will be updated as a result of acquiring new data, developing different methodologies and assumptions, and using comparatively more conservative standards or more aggressive standards. It is also expected that data quality and conceptual understanding of the carbon sequestration process will be improved over the next few years, which will refine capacity estimates.

## Reporting

The RCSPs began by compiling data that was collected in their respective Regions and submitting it to the National Carbon Sequestration Database and Geographical Information System (NATCARB). Polygons enclosing each area assessed (formation or basin) with an attached database file (.dbf) were the preferred method of reporting. In the database, a low and a high estimate of saline formation and coal capacity in metric tons of CO<sub>2</sub> 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. For storage in oil and gas formations, a capacity in metric tons of CO<sub>2</sub> was calculated for each formation, play, or region with individual or total oil and gas formation storage capacity displayed in a polygon. Data that support the calculated volumes (for example, thickness, depths, and porosity maps and grids, and any intermediate calculations such as per-unit or per-grid cell capacity) were archived by each RCSP.

Estimates of near-zero (0) capacity were acceptable for regions that have little chance of finding large-capacity storage using technologies now under consideration. An example of areas that have near-zero capacity are regions of exposed or shallow (<2,500 feet) plutonic or metamorphic basement rocks. In some assessments, these rock types do not provide adequate seals.

Placeholder values for capacity were accepted for areas that had not been assessed or which had been partly assessed but quantitative data were too incomplete to calculate a capacity (for example shale and basalt). Unassessed values were used to indicate that the area had not been studied and the presence of adequate saline, oil and gas, or unminable coal deposits was not yet available in the RCSP database. Unquantified values were used to indicate areas where assessment had been started and that data suggest that the area may have capacity; however, adequate or adequately quantitative data (for example, average porosity or thickness) were sparse or absent.

The Department of Energy (DOE) RCSP Program is intended to leverage local expertise on many aspects of carbon capture and sequestration technologies. If an alternative geographical information system (GIS) or mapping approach was required to show a Region's capacity, this approach was documented.

## Types of Geologic Environments

For the purposes of this assessment, the subsurface was categorized into five major geologic formations: saline formations, coal seams, hydrocarbon (oil and gas) formations, shale, and basalt formations. Each of these is defined and input parameters for capacity calculations are described below. Storage capacity has been quantified where possible for saline, coal, oil, and gas, whereas shale and basalts are presented as future opportunities and presented as bulk resources.

### Saline Formations

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 mg/L, which has the capacity to store large volumes of CO<sub>2</sub>. Capacities were determined for all saline formations below 2,500 feet where adequate data was available. A saline formation can include more than one named geologic formation or be defined as only part of a formation. More than one saline formation can be assessed within a vertical sequence of rocks. Many formations are part of the total CO<sub>2</sub> volume that occupies structurally defined basins, and in this case, the name of the basin is commonly used to describe multiple formations. However, in some cases, the conceptualization and terminology were not appropriate, and in these cases the customary local terminology was accepted instead. Assumptions used in this assessment included (1) saline formations are heterogeneous and therefore under multiphase conditions; (2) only 20 to 80% of the area inventoried and 25 to 75% of the formation thickness assessed would be occupied by CO<sub>2</sub>; and (3) the efficiency factor accounts for net to effective porosity, areal displacement efficiency, vertical displacement efficiency, gravity effects, and microscopic displacement efficiency.

Saline formations assessed for storage were restricted to those where the following basic criteria for the storage are met: (1) pressure and temperature conditions in the saline formation are adequate to keep the CO<sub>2</sub> in dense phase (liquid or supercritical), (2) a suitable seal is present to limit vertical flow of the CO<sub>2</sub> to the surface, and (3) salinity in the saline formation is such that injection is acceptable under provisions of the Underground Injection Control (UIC) Program. For this assessment, a depth of 2,500 feet below surface was accepted as a reasonable proxy for these criteria to be met. At a later time, new data or analysis may show sustainable storage at depths <2,500 feet.

For site-specific evaluations, exceptions may be required where local conditions indicate that a locality-specific modification is required. Examples of local conditions and locality-specific modification of this depth are

- (1) abnormally deep water table (adjust depth cutoff to assure that CO<sub>2</sub> is dense in the saline formation, or assume that a gas phase cap is acceptable);
- (2) abnormally high or low geothermal gradient (adjust depth cutoff to assure that CO<sub>2</sub> is dense in the saline formation);

- (3) seal of sufficient quality and geometry to retain CO<sub>2</sub> in dense phase in the subsurface may not be present over the entire area (reduce area [A] and thickness [h] to the volume where seal is present);
- (4) salinity is <10,000 mg/L (reduce A and h to the volume where salinity is >10,000 mg/L, or, if not applicable for a region, assume that a waiver of relevant UIC rules will be granted).

In this assessment, details of the storage mechanism within a saline formation are not specified. No distinction is made between CO<sub>2</sub> that is stored as an immiscible phase within structural or stratigraphic geologic traps; CO<sub>2</sub> that is stored as an immiscible phase outside of traps (for example, trapped in pores by capillary processes); CO<sub>2</sub> that is stored as dissolved phase in saline; and CO<sub>2</sub> that is precipitated as minerals. However, displacement of saline in the pore volume by immiscible CO<sub>2</sub> is the fundamental mechanism implicit in the calculations. This issue is explained in more detail in Appendix 3, which provides a discussion of the equivalence of displacement-based capacity to dissolution-based capacity. Researchers within the RCSP recognize that capacity estimates will be refined as conceptualization of processes and quantification of subsurface data mature. A range of storage capacity was therefore calculated reflecting these uncertainties by proving the 15 and 85% confidence level from the Monte Carlo distribution used to calculate storage efficiency (Appendix 1).

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

$$G_{CO_2} = A h_g \phi_{tot} \rho E$$

Parameter	Units*	Description
G <sub>CO2</sub>	M	Mass estimate of saline-formation CO <sub>2</sub> storage capacity
A	L <sup>2</sup>	Geographical area that defines the basin or region being assessed for CO <sub>2</sub> storage-capacity calculation
h <sub>g</sub>	L	Gross thickness of saline formations for which CO <sub>2</sub> storage is assessed within the basin or region defined by A
φ <sub>tot</sub>	L <sup>3</sup> /L <sup>3</sup>	Average porosity of entire saline formation over thickness h <sub>g</sub> . Total porosity of saline formations within each geologic unit's gross thickness divided by h <sub>g</sub>
ρ	M/L <sup>3</sup>	Density of CO <sub>2</sub> evaluated at pressure and temperature that represents storage conditions anticipated for a specific geologic unit averaged over h <sub>g</sub>
E	L <sup>3</sup> /L <sup>3</sup>	CO <sub>2</sub> Storage Efficiency Factor that reflects a fraction of the total pore volume that is filled by CO <sub>2</sub>

\* L is length; M is mass

Monte Carlo simulations estimated a range of E between 1 and 4 percent of the bulk volume of saline formations for a 15 to 85% confidence range (Appendix 1).

## Appendix A: Methodology for Development of Carbon Sequestration Capacity Estimates

This assessment was conducted at a subregional (basin or regional) scale, and the details of calculation methodologies used were determined by each RCSP. A few examples include the following:

- Create two- or three-dimensional grids of capacity and sum them.
- Average parameters across the saline formation and multiply the average values using the volumetric equation.
- Assess capacity of one or more stratigraphically distinct named formations.
- Group permeable strata more coarsely in areas of greater complexity or less well-defined stratigraphy.

These methods are acceptable as long as they approximate algebraic equality. To approximate algebraic equality, input values must be applicable to the volumes assessed. For example, it is critical that  $\phi_{tot}$  be an average that represents average porosity over the gross thickness  $hg$ . If thickness  $hg$  includes nonformation rocks, the porosity of these rocks should be represented by  $\phi_{tot}$  in a proportion similar to that of their occurrence in the formation. Furthermore,  $\phi_{tot}$  should not equal effective (or interconnected) porosity.

### Oil and Gas Reservoirs

Oil or gas reservoir storage capacity for this assessment was defined as volumes of the subsurface that have hosted natural accumulations of oil and/or gas and that could, in the future, be used to store  $CO_2$ . Mapping of the seal to oil and gas reservoirs is not required because the entrapment of hydrocarbons is considered evidence that a  $CO_2$  containment seal is present and the associated water is assumed to be nonpotable. Minimum depth was assigned by each RCSP. Production of hydrocarbons from these reservoirs has demonstrated that pores within the produced area are interconnected and can therefore 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 reservoirs with  $CO_2$ .

Storage volume methodology for oil and gas reservoirs was simplified to provide a nationwide base-case. Calculation was based on quantifying the volume of hydrocarbons produced and assuming that they could be replaced by an equivalent volume of  $CO_2$ , where both hydrocarbon and  $CO_2$  volumes were calculated at initial formation pressure or a pressure that was 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 selected by each RSCP was based on available data. Appendix 4 describes a case study suggesting that the two methods can be used as equivalents. The two methods have storage efficiency factors built into their respective methodologies. No range of capacity values is proposed for oil and gas reservoirs, reflecting a relatively good understanding of volumetrics of this system.

**Volumetrics-based  $CO_2$  Storage Estimate for Oil and Gas Reservoirs**—The volumetrics-based  $CO_2$  storage estimate uses standard industry methods to calculate original oil in place

(OOIP) or original gas in place (OGIP). OOIP is calculated by multiplying reservoir area (A), net oil column height ( $h_n$ ), average effective porosity ( $\phi_e$ ), and oil saturation (1 - water saturation as a fraction). A reservoir-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. In the equation below, this fraction is defined as E and can be derived from local experience or reservoir simulation. For site-specific studies, reservoir volumetrics involving gas require consideration of pressure and reservoir drive mechanism. Because of previous extensive experience in estimating volumetrics of reservoirs, regional, play, or reservoir-specific values supplied by each Partnership were used.

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

$$G_{CO_2} = A h_n \phi_e (1-S_w) B_o \rho E$$

Parameter	Units*	Description
$G_{CO_2}$	M	Mass estimate of hydrocarbon reservoir $CO_2$ storage capacity
A	$L^2$	Area that defines oil or gas reservoir that is assessed for $CO_2$ storage capacity calculation
$h_g$	L	Hydrocarbon column height in the reservoir
$\phi_e$	$L^3/L^3$	Average porosity over net thickness $h_n$ . Effective porosity of reservoir divided by $h_n$
$S_w$	$L^3/L^3$	Average water saturation within the total area (A) and net thickness ( $h_n$ )
B	$L^3/L^3$	Reservoir volume factor; converts standard oil or gas volume to subsurface volume (at reservoir pressure and temperature)
$\rho$	$M/L^3$	Density of $CO_2$ evaluated at pressure and temperature that represents storage conditions in the reservoir 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

It is acceptable to distribute these parameters over a geocellular grid and sum the values obtained for each cell or to multiply values averaged over the formation (GIS polygon), as long as the resulting values are approximately equivalent.

**Production-based  $CO_2$  storage estimate for oil and gas reservoirs**—A production-based  $CO_2$  storage estimate is possible if acceptable records are available on volumes of hydrocarbons produced. Produced water was not considered in the estimates, nor was injected water (waterflooding), although these volumes may be useful in site-specific calculations. It is necessary to apply an appropriate reservoir volume factor (B) to convert surface hydrocarbon volumes reported as production to subsurface volumes, including

## Appendix A: Methodology for Development of Carbon Sequestration Capacity Estimates

correction of solution gas volumes if gas production in an oil reservoir is included. No area, column height, porosity, residual water saturation, or estimation of the fraction of OOIP that is accessible to CO<sub>2</sub> was required because production reflected these reservoir characteristics. If data were available, it was possible to apply efficiency to production data to convert it to CO<sub>2</sub> storage volumes; otherwise replacement of produced hydrocarbons by CO<sub>2</sub> on a volume-for-volume basis (at reservoir pressure and temperature) was accepted.

**Simplifying assumptions for oil and gas reservoirs**—No effort was made to consider the economic aspects of oil and gas reservoirs. No distinction was made between reservoirs that were in production and those that were or would soon become depleted or abandoned. RCSP researchers are aware that sophisticated analysis of the potential for use of oil and gas reservoirs for CO<sub>2</sub> sequestration can be made, including use of CO<sub>2</sub> for enhanced oil recovery (EOR) and enhanced gas recovery (EGR). A large number of variables could be considered that potentially increase or decrease the estimate of CO<sub>2</sub> storage available in the reservoir. However, it was not feasible to standardize these variables on a homogeneous nationwide approach, but it will be of value in more focused assessments. Moreover, Appendix 4 shows a study of production and volumetric data for the Illinois Basin illustrating a simulation-based storage efficiency (that accounts for most all of these variables), with volumetrics compared very similarly to the production replacement method.

Examples of factors not explicitly considered in the production-based method that might increase the volume that could be stored include miscibility of CO<sub>2</sub> into oil, dissolution of CO<sub>2</sub> into residual and associated water, mineral trapping, and pressure decline as a result of production. Optimizing reservoir engineering via integration of reservoir characterization with well placement, completion, conformance control, and injection strategies may increase storage capacity. Parameters not considered that may limit the 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<sub>2</sub> 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<sub>2</sub> stored is equivalent to the volume of oil and gas originally trapped because of pressure perturbations of the formation during production (for example, compromise to the seal by well penetration or by deformation during production) or that seal will respond identically to trapping CO<sub>2</sub> as the original fluid stored.

### Coal Beds

The adsorptive nature of coal (quantified as sorptive capacity, expressed in standard cubic feet gas per unit volume or mass of coal) compared with that of porous media was expected to cause the range of parameters for displacement efficiency terms to be much higher than for porous media. Gas concentration from the Langmuir isotherm was substituted for the porosity that was used in other capacity calculations. We assume that delineation of most coals via mapping is better than quantification of porosity distribution in saline formations; however, some unmapped heterogeneity at a basin scale was included within the estimated value of E. The definition of unminable coal varies from region

to region due to depth distribution of the total resource relative to the rate and cost of mining.

Gas concentration is ideally determined from Langmuir adsorption isotherm data. These gas contents represent the maximum gas content adsorbed in the coals. Alternatives to using adsorption data would be using desorption data, which, in areas of underpressurized coals, will have gas-content values less than those of the Langmuir isotherm data. Desorption data can be used as a substitute for Langmuir adsorption isotherm data, recognizing that the gas-content values will be underreported, and, hence, sequestration capacity of the coals will be lower when compared with using Langmuir (saturated) values.

The volumetric equation with consistent units assumed is

$$G_{CO_2} = A h C \rho E$$

Parameter	Units*	Description
G <sub>CO<sub>2</sub></sub>	M	Mass estimate of CO <sub>2</sub> storage capacity of one or more coal beds
A	L <sup>2</sup>	Geographical area that outlines the coal basin or region for CO <sub>2</sub> storage capacity calculation
h <sub>g</sub>	L	Gross thickness of coal seam(s) for which CO <sub>2</sub> storage is assessed within the basin or region defined by A
C	L <sup>3</sup> /L <sup>3</sup>	Concentration of CO <sub>2</sub> standard volume per unit of coal volume (Langmuir or alternative); assumes 100% CO <sub>2</sub> saturated coal conditions; if on dry-ash-free (daf) basis, A and h must be corrected for daf
ρ	M/L <sup>3</sup>	Standard density of CO <sub>2</sub>
E	L <sup>3</sup> /L <sup>3</sup>	CO <sub>2</sub> Storage Efficiency Factor that reflects a fraction of the total coal bulk volume that is contacted by CO <sub>2</sub>

\* L is length; M is mass

The CO<sub>2</sub> storage efficiency factor has several components that reflect different physical barriers that inhibit CO<sub>2</sub> from contacting 100% of the coal bulk volume of a given basin or region. Depending on the definitions of area, thickness, and CO<sub>2</sub> concentration (from Langmuir), the CO<sub>2</sub> 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. Appendix 2 provides the assumptions used to estimate E for coal. Monte Carlo simulations estimated a range of E between 28 and 40%; these values provide a 15 to 85% confidence range. Details are provided in Appendix 2.

## Data Density and Uncertainty

The RCSPs worked toward assigning levels of confidence to storage estimates of specific sink types. Available data such as well penetration and seismic surveys are unevenly distributed, and the level of characterization of the subsurface both by the geoscience community and by the RCSP program is variable. In addition, the complexity of the subsurface is variable; in some areas reasonable confident extrapolations can be made between data points; in others, confidence in correlation between data points drops sharply with distance. As an example, a simple rubric is provided below for each Partnership to provide a 1 (low) to 9 (high) relative index of availability of data needed to estimate capacity and level of confidence in the assessment on a basin or formation scale.

		Confidence Indicator		
Subsurface Heterogeneity	Complex subsurface, numerous structures at spacings of <2 miles, highly discontinuous formation properties at <2 mile spacing, typical of tectonically deformed areas	5	3	1
	Moderately heterogeneous subsurface, structure and anisotropy present but repetitive at 2-10 mile spacing possible to interpolate rock properties for up to 10 miles	7	5	3
	Structural complications are infrequent and range of rock properties can be projected over areas >10 miles.	9	7	5
		Well density avg. > 1 well/square mile seismic survey spacing average >1 line per 10 linear mile	Well density avg. > 1 well/9 square mile seismic survey spacing average >1 line per 50 linear mile	Well density avg. > 1 well/100 square mile seismic line spacing average >1 line per 100 linear mile
		Data Density		

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# Appendices

## Appendix 1. Estimation of the Storage Efficiency Factor for Saline Formations (prepared by Scott Frailey)

## Appendix 2. Estimation of the Storage Efficiency Factor for Unmineable Coal Seams (prepared by Scott Frailey)

## Appendix 3. Comparison of Pore Volume Occupied by CO<sub>2</sub> Dissolution in Saline and Free Phase CO<sub>2</sub> (prepared by Scott Frailey)

## Appendix 4. Comparison of CO<sub>2</sub> Storage Estimates in Oil Formations Using Production and Volumetrics (prepared by Scott Frailey)

### Appendix I. Estimation of the Storage Efficiency Factor for Saline Formations

Efficiency is the multiplicative combination of volumetric parameters that reflect the portion of a basin’s or region’s total pore volume that CO<sub>2</sub> is expected to actually contact. The CO<sub>2</sub> storage efficiency factor for saline formations has several components that reflect different physical barriers that inhibit CO<sub>2</sub> from contacting 100 percent of the pore volume of a give basin or region. Depending on the definitions of area, thickness, and porosity, the CO<sub>2</sub> 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 capacity equation, efficiency must include terms that adjust gross thickness to net thickness and total porosity to effective porosity (interconnected).

The terms can be grouped into a single term that defines the entire basin’s/region’s pore volume and terms that reflect local formation effects in the injection area of a specific injection well. Assuming that CO<sub>2</sub> injection wells can be placed regularly throughout the basin/region to maximize storage, this group of terms is applied to the entire basin/region. Given this assumption, the capacity estimate is the maximum storage available because there is no restriction on the number of wells that could be used for the entire basin/region area. Because formation heterogeneity terms are included, this estimate could be considered a “reasonable” maximum storage estimate.

Terms included in the CO<sub>2</sub> storage efficiency factor are:

Term	Symbol (range)	Description
<b>Terms used to Define the Entire Basin/Region Pore Volume</b>		
Net to total area	$A_n/A_t$ (0.2–0.8)	Fraction of total basin/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	$\phi_e/\phi_{tot}$ (0.6–0.95)	Fraction of total porosity that is effective, i.e. interconnected
<b>Terms used to Define the Pore Volume Immediately Surrounding a Single Well CO<sub>2</sub> Injector</b>		
Areal displacement efficiency	$E_A$ (0.5–0.8)	Fraction of immediate area surrounding an injection well that can be contacted by CO <sub>2</sub> ; most likely influenced by areal geologic heterogeneity such as faults or permeability anisotropy.
Vertical displacement efficiency	$E_v$ (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 <sub>2</sub> 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 compared with others, the CO <sub>2</sub> will fill this one quickly and leave the other zones with less CO <sub>2</sub> or no CO <sub>2</sub> in them.
Gravity	$E_g$ (0.2–0.6)	Fraction of net thickness that is contacted by CO <sub>2</sub> as a consequence of the density difference between CO <sub>2</sub> and in situ water. In other words, 1-E <sub>g</sub> is that portion of the net thickness <b>not</b> contacted by CO <sub>2</sub> because the CO <sub>2</sub> rises within the geologic unit.
Microscopic displacement efficiency	$E_d$ (0.5–0.8)	Portion of the CO <sub>2</sub> -contacted, water-filled pore volume that can be replaced by CO <sub>2</sub> . E <sub>d</sub> is directly related to irreducible water saturation in the presence of CO <sub>2</sub> .

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 4<sup>th</sup> and 5<sup>th</sup> cases were run to assess sensitivity to the input parameters and were 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<sub>50</sub> case seems less sensitive to choice of distribution. P<sub>15</sub> and P<sub>85</sub> 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<sub>50</sub> E of approximately 1.8 to 2.2%.

Case	Parameter	Range	Distribution	P <sub>15</sub>	P <sub>50</sub>	P <sub>85</sub>	Comment
Base-uniform	$A_n/A_t$	0.2–0.8	Uniform	1.6	2.7	4.2	
	$h_n/h_g$	0.25–0.75	Uniform				
	$\phi_e/\phi_{tot}$	0.6–0.95	Uniform				
	$E_A$	0.5–0.8	Uniform				
	$E_I$	0.6–0.9	Uniform				
	$E_g$	0.2–0.6	Uniform				
Base-normal with variance 1.0 max-min difference	$A_n/A_t$	0.2–0.8	Normal	0.44	1.8	4.1	Median given as midpoint of range; variance given as max less median (broad flat normal distribution)
	$h_n/h_g$	0.25–0.75	Normal				
	$\phi_e/\phi_{tot}$	0.6–0.95	Normal				
	$E_A$	0.5–0.8	Normal				
	$E_I$	0.6–0.9	Normal				
	$E_g$	0.2–0.6	Normal				
Base-normal with variance 2.0 max-min difference	$A_n/A_t$	0.2–0.8	Normal	0.22	1.9	10	Median given as midpoint of range; variance given as twice max less median (very broad, flat normal distribution) P <sub>85</sub> likely too high as wide distribution makes values of some components over 1.0
	$h_n/h_g$	0.25–0.75	Normal				
	$\phi_e/\phi_{tot}$	0.6–0.95	Normal				
	$E_A$	0.5–0.8	Normal				
	$E_I$	0.6–0.9	Normal				
	$E_g$	0.2–0.6	Normal				
Base-normal with variance ½ max-min difference	$A_n/A_t$	0.2–0.8	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)
	$h_n/h_g$	0.25–0.75	Normal				
	$\phi_e/\phi_{tot}$	0.6–0.95	Normal				
	$E_A$	0.5–0.8	Normal				
	$E_I$	0.6–0.9	Normal				
	$E_g$	0.2–0.6	Normal				
Base-normal with variance 1.0 max-min difference with minimum imposed	$A_n/A_t$	0.2–0.8	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
	$h_n/h_g$	0.25–0.75	Normal				
	$\phi_e/\phi_{tot}$	0.6–0.95	Normal				
	$E_A$	0.5–0.8	Normal				
	$E_I$	0.6–0.9	Normal				
	$E_g$	0.2–0.6	Normal				
Base-mixed distribution	$A_n/A_t$	0.2–0.8	Uniform	0.65	1.9	4.4	Change in distribution based on possible petrophysical distribution
	$h_n/h_g$	0.25–0.75	Normal				
	$\phi_e/\phi_{tot}$	0.6–0.95	Uniform				
	$E_A$	0.5–0.8	Normal				
	$E_I$	0.6–0.9	Log Normal				
	$E_g$	0.2–0.6	Normal				
$E_d$	0.5–0.8	Normal					

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% confidence range.

## Appendix 2. Estimation of Storage Efficiency Factor for Unminable Coal Seams

Efficiency is the multiplicative combination of volumetric parameters that reflect the portion of a basin’s or region’s coal bulk volume that CO<sub>2</sub> is expected to actually contact.

The terms that describe this volume can be grouped into one term that defines the entire basin’s/region’s coal bulk volume and the local formation effects in the injection area of a specific injection well. Assuming that CO<sub>2</sub> injection wells can be placed regularly throughout the basin/region to maximize the basin’s coal storage, this group of terms is applied to the entire basin/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/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 on the next page were modified for coal. Because of the lack of extensive enhanced coalbed methane (ECBM) field experience, ranges were 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 coals, the permeability reduction expected in coal due to CO<sub>2</sub> swelling will most likely have a “correcting” mechanism, which reduces the velocity of CO<sub>2</sub> as the coal swells and redirects CO<sub>2</sub> to lesser-swept parts of the coal seam. Because coals are thinner than saline formations, gravity effects will likely be very slight, so this term was raised also. The bulk coal terms ( $A/A$  and  $h/h$ ) were increased because most basin coals would be better defined compared with saline formations.

## Appendix A: Methodology for Development of Carbon Sequestration Capacity Estimates—Appendix 2

Terms included in the CO<sub>2</sub> storage efficiency factor for coal are:

Term	Symbol (range)	Description
<b>Terms used to Define the Entire Basin/Region Bulk Coal Volume</b>		
Net to total area	$A_n/A_t$ (0.6–0.8)	Fraction of total basin/region area that has bulk coal present; used if known or suspected locations are within a basin/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.
<b>Terms used to Define the Coal Volume Immediately Surrounding a Single Well CO<sub>2</sub> Injector</b>		
Areal displacement efficiency	$E_A$ (0.7–0.95)	Fraction of the immediate area surrounding an injection well that can be contacted by CO <sub>2</sub> ; most likely influenced by areal geologic heterogeneity such as faults or permeability anisotropy.
Vertical displacement efficiency	$E_t$ (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 <sub>2</sub> will fill this one quickly and leave the other zones with less CO <sub>2</sub> or no CO <sub>2</sub> in them.
Gravity	$E_g$ (0.9–1.0)	Fraction of the net thickness that is contacted by CO <sub>2</sub> as a consequence of the density difference between CO <sub>2</sub> and the in-situ water in the cleats. In other words, 1- $E_g$ is the portion of the net thickness not contacted by CO <sub>2</sub> because the CO <sub>2</sub> 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 <sub>2</sub> 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<sub>50</sub> case seems less sensitive to choice of distribution. P<sub>15</sub> and P<sub>85</sub> 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<sub>50</sub> E of 33%.

Case	Parameter	Range	Distribution	P <sub>15</sub>	P <sub>50</sub>	P <sub>85</sub>	Comment
Base-uniform	$A_n/A_t$	0.6–0.8	Uniform	28	33	40	
	$h_n/h_g$	0.75–0.90	Uniform				
	$E_A$	0.7–0.95	Uniform				
	$E_t$	0.8–0.95	Uniform				
	$E_g$	0.9–1.0	Uniform				
	$E_d$	0.75–0.95	Uniform				
Base-normal with variance 1.0 max-min difference	$A_n/A_t$	0.6–0.8	Normal	25	33	43	Median given as midpoint of range; variance given as max less median (broad flat normal distribution)
	$h_n/h_g$	0.75–0.90	Normal				
	$E_A$	0.7–0.95	Normal				
	$E_t$	0.8–0.95	Normal				
	$E_g$	0.9–1.0	Normal				
	$E_d$	0.75–0.95	Normal				
Base-normal with variance ½ max-min difference	$A_n/A_t$	0.6–0.8	Normal	29	33	38	Median given as midpoint of range; variance given as one-half max less median (narrow, spike normal distribution)
	$h_n/h_g$	0.75–0.90	Normal				
	$E_A$	0.7–0.95	Normal				
	$E_t$	0.8–0.95	Normal				
	$E_g$	0.9–1.0	Normal				
	$E_d$	0.75–0.95	Normal				
Base-normal with variance 2.0 max-min difference	$A_n/A_t$	0.6–0.8	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
	$h_n/h_g$	0.75–0.90	Normal				
	$E_A$	0.7–0.95	Normal				
	$E_t$	0.8–0.95	Normal				
	$E_g$	0.9–1.0	Normal				
	$E_d$	0.75–0.95	Normal				
Base-normal with variance 1.0 max-min difference with minimum imposed	$A_n/A_t$	0.6–0.8	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
	$h_n/h_g$	0.75–0.90	Normal				
	$E_A$	0.7–0.95	Normal				
	$E_t$	0.8–0.95	Normal				
	$E_g$	0.9–1.0	Normal				
	$E_d$	0.75–0.95	Normal				

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

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

## Appendix 3. Comparison of Pore Volume Occupied by CO<sub>2</sub> Dissolution in Saline and Free Phase CO<sub>2</sub>

Because some RCSPs used dissolution of CO<sub>2</sub> in water and other RCSPs used free-phase CO<sub>2</sub> to estimate their respective basins/regions' storage capacity, the total storage efficiency (E) derived for use in one technique is not equivalent or applicable to the other.

The dominant mechanism of CO<sub>2</sub> storage may change from storage of an immiscible free-phase to CO<sub>2</sub> dissolved in water over time, and the proportion of dissolved CO<sub>2</sub> to a basin's/region's pore volume would be larger than the proportion contacted by free phase CO<sub>2</sub>. Several RCSPs focused on dissolved storage for capacity calculation. To avoid any RCSP's repeating a rigorous calculation of capacity with new methodology, a method of converting E for free-phase CO<sub>2</sub> to the equivalent E for dissolved CO<sub>2</sub> 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<sub>2</sub> is 48.55 pound mass per cubic foot (lbm/ft<sup>3</sup>), 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<sub>2</sub> 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<sup>3</sup> of pore volume, the 48.55 lbm of free-phase CO<sub>2</sub> occupies 1 ft<sup>3</sup> of pore space.

$$\left( \frac{118 \text{ scf} - \text{CO}_2}{\text{stb} - \text{water}} \right) \left( \frac{1 \text{ bbl}}{5.615 \text{ ft}^3} \right) \left( \frac{1 \text{ ton} - \text{CO}_2}{17,140 \text{ scf} - \text{CO}_2} \right) \left( \frac{2000 \text{ lbm}}{\text{ton}} \right) = \frac{2.452 \text{ lbm} - \text{CO}_2}{\text{ft}^3 - \text{pore volume}}$$

For dissolution of CO<sub>2</sub> into water, 1 ft<sup>3</sup> of pore space is occupied by water; 118 scf of CO<sub>2</sub> 100% saturates a stb of 100,000 ppm water at 140 °F and 3500 psia. Converting to lbm/ft<sup>3</sup>

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<sup>3</sup> of water volume due to dissolution of CO<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub>, 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.

## Appendix 4. Comparison of CO<sub>2</sub> Storage Estimates in Oil Formations Using Production and Volumetrics

### Background

The methodology chosen to assess CO<sub>2</sub> storage in oil formations depends primarily on available data. Two distinct data types are production and formation geometry. Production data include cumulative oil and (hydrocarbon) gas. For this analysis, cumulative gas production was considered for gas formations, except for associated gas of oil formations. Water production and water injection are not considered in this assessment; however, they might be considered in the future. Formation geometry data would need to include area, thickness, porosity, water saturation, and formation volume factors.

### Production-Based CO<sub>2</sub> Storage Estimate

A simple method proposed in this assessment is to replace cumulative hydrocarbon production with an equivalent formation volume of CO<sub>2</sub>. Doing so would require the hydrocarbon formation volume factor to convert the surface volume of hydrocarbon to formation pressure and temperature and CO<sub>2</sub> density to find the mass of CO<sub>2</sub> that would occupy the pore space previously occupied by oil or gas.

An advantage of using hydrocarbon production to estimate CO<sub>2</sub> storage is that production reflects a hydrocarbon (production) recovery factor, which is a portion of the original oil volume that was produced. (This recovery factor, much like the storage efficiency factor, would include formation heterogeneity influences on cumulative oil production). Disadvantages of using hydrocarbon production to estimate CO<sub>2</sub> storage include incomplete data records and various stages of oil-field maturity (percent depleted).

Replacement of produced fluids with CO<sub>2</sub> requires close examination to understand the inherent assumptions required to assess CO<sub>2</sub> storage using cumulative fluid production. When oil is produced from a formation during primary production, either associated hydrocarbon gas or water replaces the oil within the pore space. If the formation was waterflooded, a portion or

all of the free gas is removed and additional oil is produced; both are replaced by water. In any case, using an oil-production-based estimate for CO<sub>2</sub> storage, it is necessary to assume that the fluids that replaced the oil can be replaced with CO<sub>2</sub>. Also, using cumulative oil production alone does not include the volume of CO<sub>2</sub> that would replace oil produced as a consequence of CO<sub>2</sub> EOR or dissolution of CO<sub>2</sub> into in situ oil and water.

Use of production (and injection) data to estimate CO<sub>2</sub> storage capacity requires assumptions of natural formation drive mechanisms, production history, and CO<sub>2</sub> replacement ratio. For example, if the natural drive mechanism were solution gas drive and a large portion of free gas were liberated in situ and subsequently produced, use of oil and gas production to determine CO<sub>2</sub> storage would be appropriate. However, if the natural drive mechanism had been water encroachment via an underlying saline formation, oil may have been replaced with an equivalent volume of water. Stored CO<sub>2</sub> would have to force water out of the pore space similar to storage in a saline formation, and replacement of oil production with CO<sub>2</sub> may be overly optimistic.

Use of water and gas production and injection may be done on a field by field basis if data are available; however, this level of assessment is not expected for this analysis. Cumulative water production and injection are likely very large and similar in magnitude for mature oil formations; the difference would not afford much storage. Additionally, much of the mobile water can most likely be displaced during the CO<sub>2</sub> injection process. If a large portion of cumulative gas production were from an original gas cap, use of gas production to estimate CO<sub>2</sub> storage would likely be a good approximation; however, if a large portion of the gas production were from solution gas, the use of gas production would overestimate CO<sub>2</sub> storage in an oil formation.

## Volumetrics-Based CO<sub>2</sub> Storage Estimate

Use of volumetrics to estimate CO<sub>2</sub> storage is based on an estimate of original oil in place (OOIP). A fraction of the OOIP is assumed to be replaced by CO<sub>2</sub> (storage efficiency factor). This fraction could be derived from historical observations of the West Texas CO<sub>2</sub> experience or compositional simulation of the CO<sub>2</sub>-EOR process for general geologic models of a basin. Because these approaches are based on the CO<sub>2</sub> injection process, all of the storage mechanisms (free phase CO<sub>2</sub>, dissolved CO<sub>2</sub> in water and oil) modeled and production variations associated with primary production and waterflooding are included in the storage efficiency factor.

## Comparison

As a result of the data available within each region, some RCSPs used production and some used volumetrics. To develop a National storage estimates using comparative methodology, an adjustment to one method's results would be needed to have a consistent capacity estimate between regions. Data sets that had both types of data for the same fields were thus required. Two data sets were available to compare the CO<sub>2</sub> storage estimates using oil production and volumetrics. For the Illinois Basin, a data set of cumulative oil production by field and formation geometry data by formation was available for comparison.

A second data set based on compositional simulation results using Landmark's VIP software was also available. In Phase I the Midwest Geologic Sequestration Consortium (MGSC) modeled three geologic units in nine different oil fields in the Illinois Basin. The geologic units were selected from the most prolific in the Basin. Only very qualitative history matching was done because the main goal was to have geologic models that represented the Basin's oil formations. Moreover, ultimate oil recovery was the goal, not specific, historical, field performance. Each formation was simulated under miscible and immiscible conditions. Consequently, this data set provided 18 model results to compare each method with the actual CO<sub>2</sub> storage estimated in the model. All models had 25 years of solution gas drive, followed by 40 years of waterflooding, followed by 20 years of CO<sub>2</sub> EOR. WAG or continuous CO<sub>2</sub> injection; however, the continuous data set was only used for comparison because it was expected to be a more likely scenario in a predominantly sequestration (vs. a predominantly EOR) environment.

## Compositional Modeling Data Set

For each geologic formation, a range of CO<sub>2</sub> storage factors for miscible and immiscible conditions were derived from the compositional simulation results. The average of this storage factor range was applied to the OOIP of each model to estimate the CO<sub>2</sub> stored. (Note that if the exact storage factor derived from each model had been applied to that specific model, the exact CO<sub>2</sub> storage volume would have been found.) Production-based CO<sub>2</sub> storage used oil production only. Actual storage is calculated from the model's gas injection and production.

The estimate of CO<sub>2</sub> storage using production data is slightly higher than the actual storage, and the CO<sub>2</sub> storage estimate using volumetrics is slightly lower than the actual storage (Figure 1). The 1:1 line would be a perfect prediction.

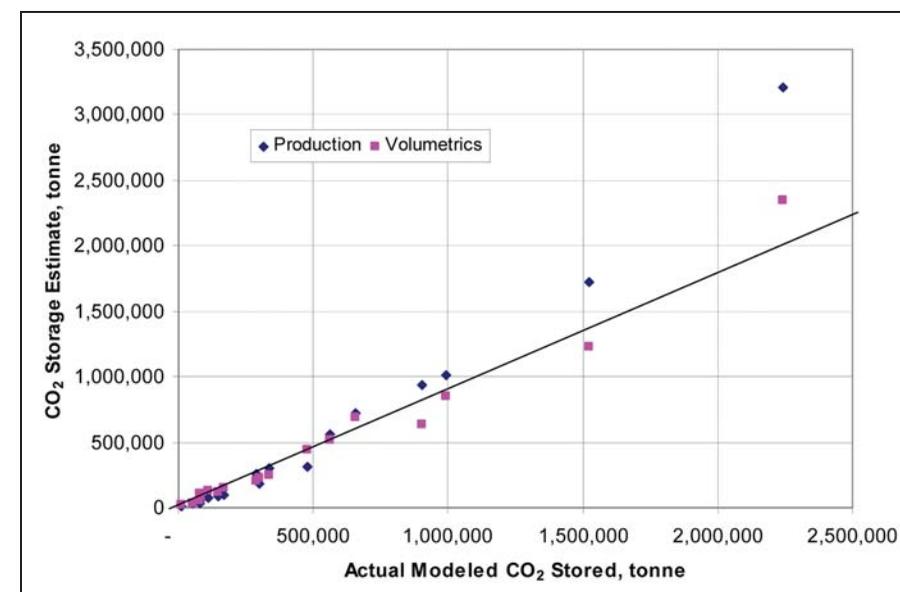


Figure 1. Comparison between CO<sub>2</sub> storage estimates on the basis of cumulative oil production (primary and waterflooding) and volumetrics using a storage factor derived from compositional simulation with the actual mass of CO<sub>2</sub> stored using the models.

When oil production is used, the trend is very similar to that of actual storage of up to 1 million tonne of CO<sub>2</sub> and then the general trend starts to deviate upward somewhat substantially, but only with two points. The volumetrics-based estimate is very similar to the actual storage of up to 0.6 million tonne of CO<sub>2</sub>; however, the overall trend follows the 1:1 slope. Trendlines through the data (not shown) show that the volumetrics-based method is closer to fitting the 1:1 curve (slope of 0.96) and a y-intercept of zero (31 ktonne), as compared with the trendline through the production-based estimate (slope of 1.3 and y-intercept of 134 ktonne).

Figure 2 is a direct comparison of volumetrics- and production-based storage estimates. The production-based estimate overpredicts, as compared with the volumetrics-based method

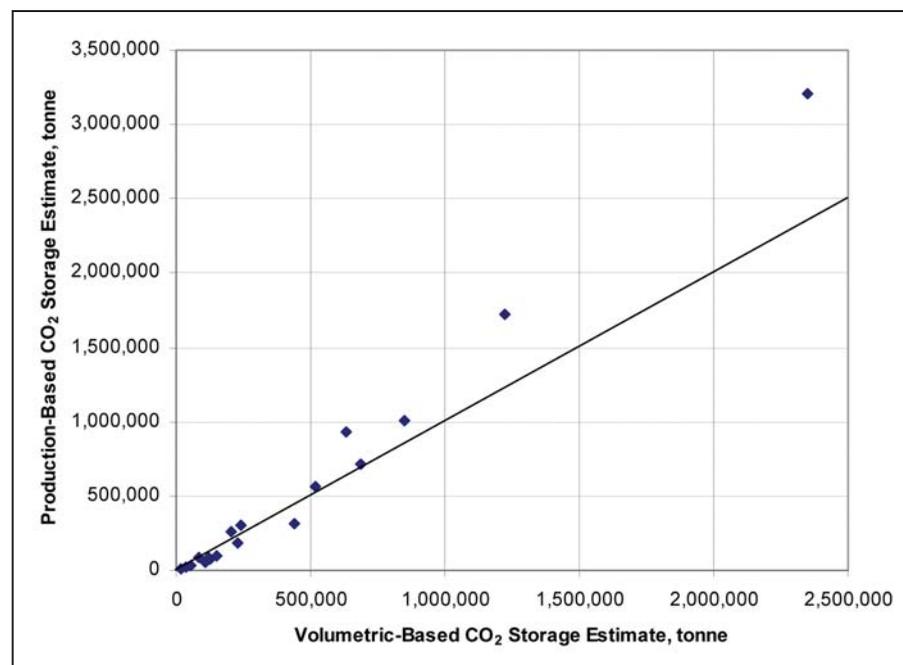


Figure 2. A direct comparison between volumetrics- and production-based CO<sub>2</sub> storage shows the slight overprediction of the production method compared with the 1:1 line shown.

Whereas the trend indicates that at higher storage values, the production-based method may overpredict storage, the simulation data set suggests that replacing cumulative oil production with an equivalent volume of CO<sub>2</sub> is an acceptable substitute for simulation-based storage factors.

### Illinois Basin Oil-Field Data Set

Cumulative oil production is available by field for many oil fields in the Illinois Basin. Exceptions are several of the Kentucky oil fields, where no oil production was available. For fields that were drilled pre-law (1939), the Basin's oil-production records are questionable. Oil fields with very low (<1,000 bbl) reported production were removed. Additionally, shallower oil fields are the earliest discovered and are generally expected to have poorer production records.

Figure 3 is a comparison between production- and volumetrics-based CO<sub>2</sub> storage estimates. The trendline through the data has a slope of 1.08 and a y-intercept of 22 ktonne, which indicates very good comparison between the methods. To improve visualization of the data, Figure 4 is the same data on a log-log scale.

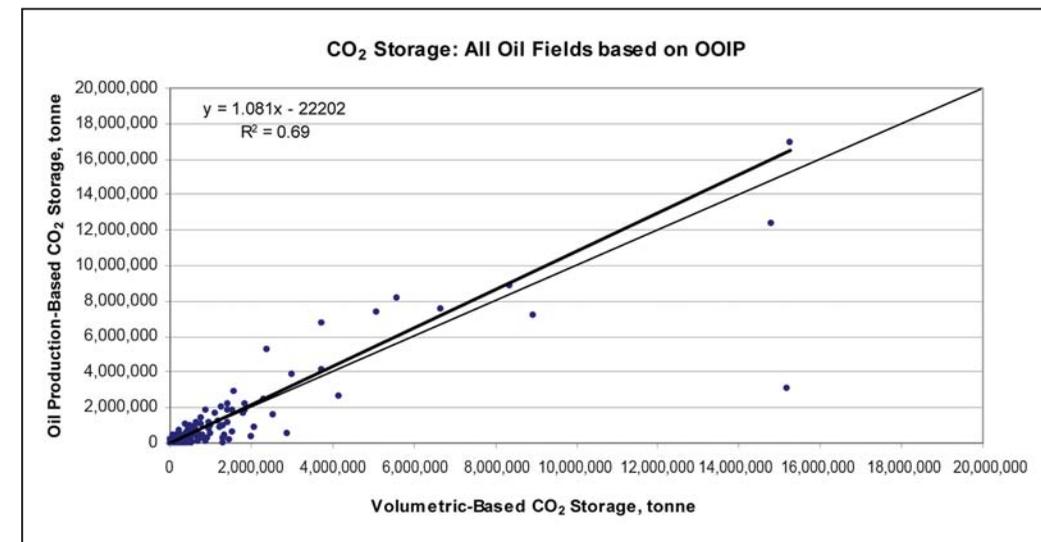


Figure 3. Cartesian plot of Illinois Basin oil fields with reported cumulative oil production exceeding 1,000 bbl. The trendline shows that each method gives comparable results.

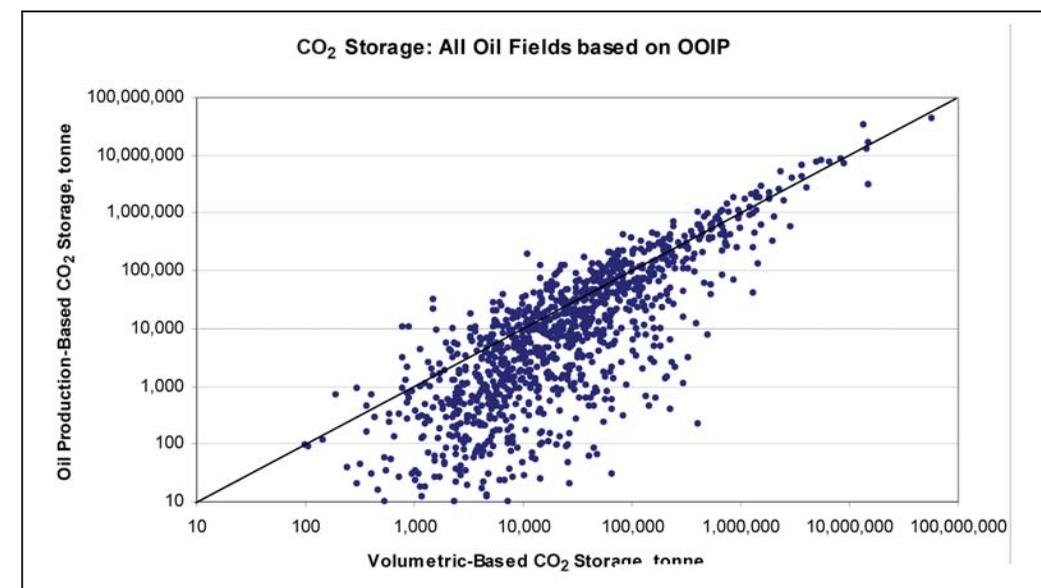


Figure 4. Log-log plot of Figure 3. Lower reported oil production yields lower calculated CO<sub>2</sub> storage using the cumulative oil-production method. The volumetrics method is independent of reported oil production and shows relatively higher CO<sub>2</sub> storage for oil fields with reported low oil production.

The log-log plot shows that relatively smaller oil fields tend to have lesser oil production reported—note the trend of the data to scatter more in the lower left of Figure 4.

To further understand the scatter in the data, the data were separated by cumulative oil, OOIP, and miscibility type. Classifying the Illinois Basin oil fields by cumulative production shows that those oil fields with relatively higher reported production have a more similar trend between the two methods (Figure 5). A trendline through each data grouping has a slope of about 0.85, which can be interpreted that the oil-production-based method is underpredicting by 15%. (The y-intercepts were relatively close to zero considering the maximum x and y-axis values.)

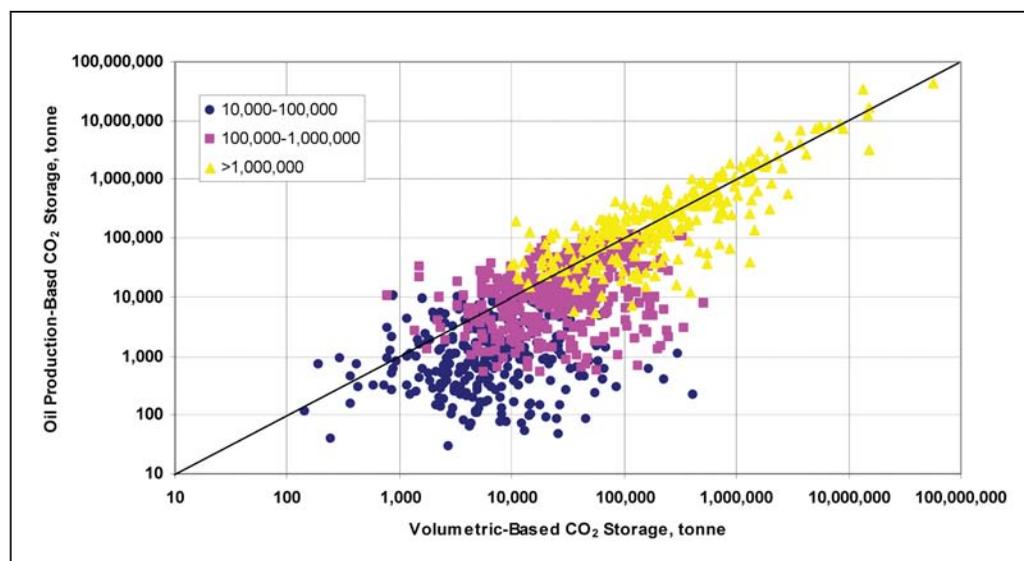


Figure 5. Oil fields in the basin are identified by three ranges of cumulative oil. Oil fields with larger reported oil production give relatively results similar to those between production- and volumetric-based methods.

To see the effects of OOIP on calculated storage estimates, fields were classified on the basis of ranges of volumetrically calculated OOIP (Figure 6). There is no cutoff of >1,000-bbl production. In comparison with Figure 5, the trend of Figure 6 shows the influence of low reported oil production.

In general, cumulative oil production makes a better prediction for larger oil fields, and smaller oil fields are more influenced by underreporting of oil production. For Illinois Basin fields, underreporting of oil production resulted in underpredicting CO<sub>2</sub> storage by 2 to 3 orders of magnitude.

Because MGSC divided oil fields according to miscibility type (miscible, immiscible, and near-miscible), oil fields in the study were divided according to miscibility type, too (Figure 7). (“Near-miscible” was for pressure and temperatures that were considered too close to be able to label an entire field as either miscible or immiscible and would have to be classified on a formation-by-formation basis within each field.) Miscibility classification was based primarily on depth, as well as anticipated pressure and temperature anticipated at these depths using a range of gradients.

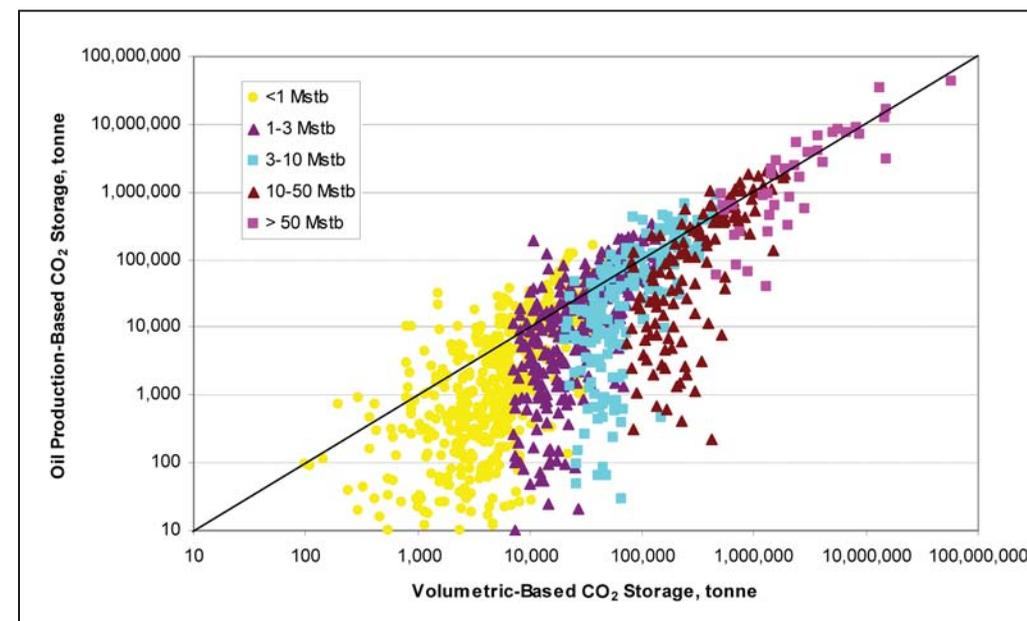


Figure 6. Oil fields in the basin are identified by three ranges of OOIP. Oil fields with larger volumetrically calculated OOIP (>50 Mstb) give results relatively similar to those between production- and volumetric-based methods. For <50 Mstb, a large discrepancy is present, which is attributed to poorly reported oil production in the early history of the basin. (M is million)

Figure 7 suggests that cumulative oil production gives inferior results for immiscible CO<sub>2</sub> EOR formations. However, it is more likely an indication of production records. Immiscible fields are shallower than miscible and near-miscible classified oil fields. Generally in the Illinois Basin, shallow oil fields were discovered early in the Basin’s history and have less-reliable production data. This plot further emphasizes the effect of poor production data on the CO<sub>2</sub> storage estimate with this method.

## Summary

Using the cumulative oil production method in the Illinois Basin underpredicted CO<sub>2</sub> storage compared with the volumetric method, probably because of questionable pre-law production records. When exact production data (simulation dataset) were available, simulations suggest that the production-based method slightly overpredicts CO<sub>2</sub> storage, with increasing overprediction occurring at higher storage values.

In fields with good production data, the production-based method will give good results. In fields with underreported oil production, the CO<sub>2</sub> storage estimate may be too low by 2 to 3 orders of magnitude.

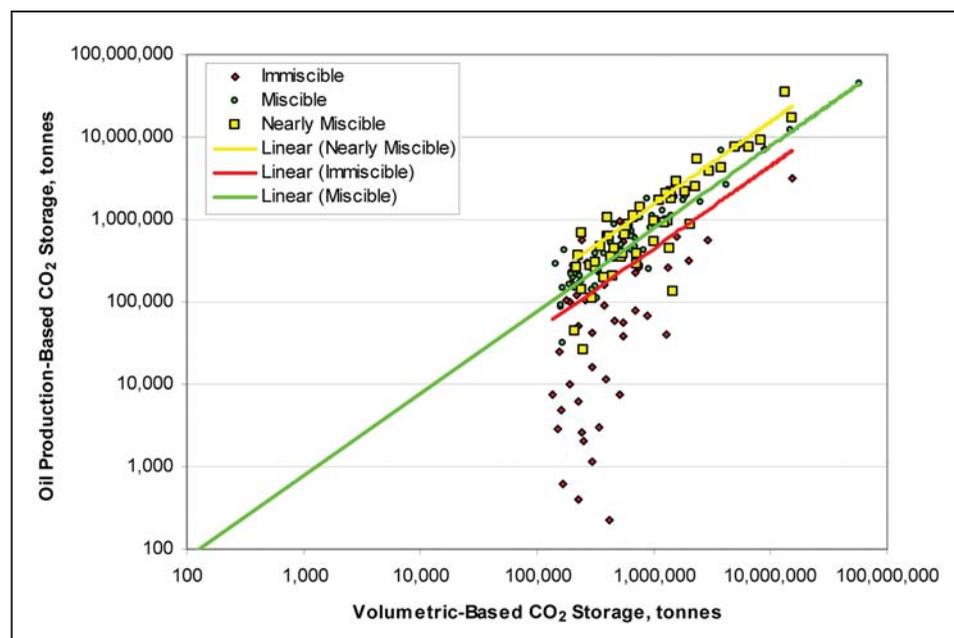


Figure 7. Oil fields in the basin are identified by miscibility classification, which is primarily governed by depth. Deeper oil fields with classifications of miscible and near-miscible show very similar storage estimates between the two methods.

### Recommendation

The cumulative-oil-production-based method may slightly overpredict CO<sub>2</sub> storage capacity when good oil-production records are available and underestimate storage when poor production records are available. It is anticipated that the magnitude of the factor will have slight to modest effects on the storage estimate. In the Illinois Basin, lack of good production data accounted for a 15% underprediction of CO<sub>2</sub> storage using the production method.

On the basis of this study using the Illinois oil-field database, it is recommended that replacing cumulative oil production (primary and secondary) with an equivalent volume of CO<sub>2</sub> is an effective means of estimating CO<sub>2</sub> storage for oil formations, as compared with using compositional simulation-based storage factors with volumetrics. For National storage estimates that combines all storage sinks, in comparison with the storage in saline formations, any adjustment to the oil-field formation estimate would be of minimal consequence.

**No change to the RCSPs' Phase I estimates of CO<sub>2</sub> storage in oil reservoirs is recommended.**

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Printed in the United States on recycled paper 

March 2007