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U.S. Department of Energy's Regional Carbon Sequestration Partnership Initiative: Update on Validation and Development Phases

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Abstract

The U.S. Department of Energy (DOE) is the lead federal agency for the development and deployment of carbon sequestration technologies. The Regional Carbon Sequestration Partnerships (RCSPs) are the mechanism DOE utilizes to prove the technology and to develop human capital, stakeholder networks, information for regulatory policy, best practices documents and training to work toward the commercialization of carbon capture and storage (CCS). The RCSPs are tasked with determining the most suitable technologies, regulations, and

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infrastructure for carbon capture, transport, and storage in their respective geographic areas of responsibility. The seven partnerships include more than 400 state agencies, universities, national laboratories, private companies, and environmental organizations, spanning 43 states and four Canadian provinces.

The Regional Partnerships Initiative is being implemented in three phases: Characterization, Validation, and Development. The initial Characterization Phase began in 2003 and was completed in 2005 and focused on characterization of CO_2 storage potential within each region. It was followed by the Validation Phase, which began in 2005 and is nearing completion in 2011. The focus of the Validation Phase has been on small-scale field tests throughout the seven partnerships in various formation types such as saline, oil-bearing, and coal seams. The Validation Phase has characterized suitable CO_2 storage reservoirs and identified the need for comprehensive legal and regulatory frameworks to enable commercial-scale CCS deployment. Finally, the Development Phase will consist of a series of large-scale, one-million-ton, injection tests throughout the United States and Canada. The objective of these large-scale tests is to identify the regulatory path or challenges in permitting CCS projects, to demonstrate the technology can inject CO_2 safely, and to verify its permanence in geologic formations in preparation for the commercialization of geologic sequestration.

The United States has been recognized as having one of the largest and most effective programs in the world to develop and deploy carbon capture and storage (CCS) technologies to mitigate global climate change. The Carbon Sequestration Program being implemented by the DOE's Office of Fossil Energy and managed by the National Energy Technology Laboratory is helping to develop technologies to capture, separate, and store carbon dioxide (CO_2) in order to reduce greenhouse gas emissions without adversely influencing energy use or hindering economic growth [1] [2]. NETL envisions having a technology portfolio of safe, cost-effective, commercial-scale greenhouse gas capture, storage, and mitigation technologies that are available for commercial deployment beginning in 2020. NETL's primary carbon sequestration research and development (R&D) objectives are (1) lowering the cost and energy penalty associated with CO_2 capture from large point sources; and (2) improving the understanding of factors affecting CO_2 storage permanence, capacity, and safety in geologic formations and terrestrial ecosystems. Three key elements of this program that focus on attaining these goals are (1) Core Research and Development (Core R&D), (2) Infrastructure, highlighted by DOE's Regional Carbon Sequestration Partnerships (RCSPs), and (3) Global Collaborations with international CCS efforts.

The seven partnerships formed through the RCSP Initiative are tasked to determine the best geologic storage approaches and develop the technologies to permanently store CO_2 for their specific regions: Big Sky Carbon Sequestration Partnership (BIG SKY), Midwest Geological Sequestration Consortium (MGSC), Midwest Regional Carbon Sequestration Partnership (MRCSP), The Plains CO_2 Reduction Partnership (PCOR), Southeast Regional Carbon Sequestration Partnership (SECARB), Southwest Regional Partnership on Carbon Sequestration (SWP) and West Coast Regional Carbon Sequestration Partnership (WESTCARB). The RCSP Initiative is being implemented in three phases: (1) Characterization Phase (2003 – 2005), (2) Validation Phase (2005 – 2011), and (3) Development Phase (2008 – 2018). The Validation Phase evaluates promising CO_2 sequestration opportunities through a series small-scale (<1 million metric tons CO_2) field tests to develop understanding of injectivity, capacity, and storability of CO_2 in the various geologic formations within a wide-range of depositional environments. Experiences gained and lessons learned from this phase are being utilized to (1) provide a foundation for implementation of the large-scale field tests in the Development Phase, (2) develop "best practices" manuals, and (3) facilitate future CCS opportunities world-wide.

The Validation Phase field tests were conducted on the most promising storage formation types in rock types representative of the varying depositional environments that are present both in North America and around the world. These tests targeted four geologic storage types: saline formations, oil and gas reservoirs, unmineable coal seams, and basalt formations (Figure 1). These first field injection projects were akin to exploration projects in the petroleum industry. They were designed to test areas where regional mapping and depositional models indicated that storage resource would be present but additional subsurface information was needed to verify storage resource and injectivity. Acquired well data have been very instrumental in further refinement of regional storage resource calculations within each RCSP. The completed tests have provided valuable information to better understand each region's geologic storage potential and determine specific areas within each RCSP that are in need of future research.

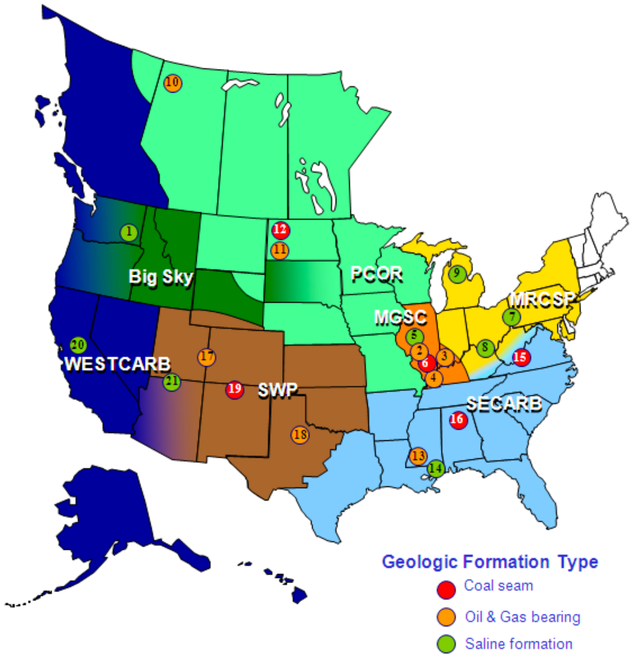

Figure 1: RCSP Validation Phase Small-Scale Geologic Field Tests.

Lessons learned from these Validation Phase projects are being integrated into the larger-scale projects in the Development Phase, which includes a more detailed characterization, and injection and monitoring of larger volumes of CO_2 in subsurface formations. DOE is also compiling these lessons learned from the RCSPs in a series of six Best Practices Manuals. Three of these: *Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations, Public Outreach and Education for Carbon Storage Projects and Site Screening, Site Selection and Initial Characterization of CO_2 in Deep Geologic Formations*, have been released and are available on the NETL website in the 2010 Carbon Sequestration Project Portfolio or on the Reference Shelf. The remaining three manuals, covering Simulation and Risk Assessment, Well Construction, Operation and Completion, and Terrestrial Sequestration, will be released in the 2010/2011 time frame.

Saline formations targeted for geologic storage are porous sedimentary deposits saturated with brine having salinity greater than 10,000 mg/l total dissolved solids (TDS). Such formations are widely distributed globally and the 2008 National Carbon Atlas estimates of 3,300 to 12,600 billion metric tons of Prospective Storage of CO_2 in saline formations throughout North America [3]. However, even though current storage estimates are large, greater understanding of the geology is critical to determining site-specific storage potentials. The wide ranges in current regional assessments of saline formations are partly due to lack of historic and current subsurface information and analyses on these saline formations. Even in areas of oil and natural gas exploration or production where wells may exist, they typically have not been drilled deep enough to provide data on underlying saline formations; however, in areas that are not hydrocarbon- producing, deep wells typically are very limited. The RCSP Initiative planned for approximately one third of its Validation tests to be conducted in saline storage formations of various depositional settings to further understand the subsurface characteristics of these saline formations [4]. Table 1 summarizes in detail the specific geologic conditions for the five completed field tests.

Table 1: Summary of geologic conditions at selected RCSP Validation Phase field tests injecting in saline formations

Geologic Provinces	Injected Volume (CO_2)	Storage Formation (Thickness)	Perm (mD)	Avg Phi (%)	Depositional Environment	Confining System (Thickness)
MRCSP – Michigan Basin	60,000 metric tons	Bass Island Dolomites (73 feet)	22 - 54	13%	Shallow Shelf (Carbonates)	Amherstburg (2,000 feet)
MRCSP – Cincinnati Arch	1,000 metric tons	Mt. Simon Sandstone (300 feet)	70 – 100	18%	Strandplain (Clastics)	Eau Claire Shale (400 feet)
SECARB – Mississippi Gulf Coast	2,740 metric tons	Lower Tuscaloosa (120 feet)	800 – 1,500	24%	Delta Marine (Clastics)	Marine Tuscaloosa (500 feet) Midway Shale (350 feet) Selma Chalk/Austin (1,300 feet)
WESTCARB – Colorado Plateau	Insufficient perm for injection	Naco/Martin Formations (700 feet)	0.015	10.5%	Shallow Shelf (Carbonates)	Supai Formation (1,900 feet)
MRCSP – Appalachian Basin	<50 metric tons	Oriskany (31 feet) Salina (200 feet) Clinton (67 feet)	0.1	6%	Shallow Shelf (Clastics)	Chagrin Shale (1,000 feet) Lower Huron Shale (1,400 feet) Rhinestreet Shale (700 feet)

The five Validation tests investigated storage formations in rocks of five different depositional environments: shallow shelf, strandplain, delta-marine, nearshore and deep marine. As previously mentioned, these tests were considered exploratory, so sometimes the results were positive and other times, negative. Those formations that were found to have both good permeability (average 22-2,300 mD) and porosity (average 8-25%) had good injection capabilities. The Michigan Basin, Cincinnati Arch, and Mississippi Gulf Coast test locations had a good combination of porosity and permeability. The injection zone was capable of accepting CO_2 at an effective rate and volume and the CO_2 was retained within the target formation by the confining system, as expected. The small-scale tests in the target formations of the Appalachian and Colorado Plateau provinces did not have sufficient permeability and, as a result, did not have successful injections.

Some of these results indicate the challenges of using generalized regional stratigraphic information to develop storage potential estimates. For example, the poor permeability found for the Appalachian and Colorado Plateau target formations does not mean that there is no storage potential in these provinces but is an indication of the lack of availability of sufficiently detailed subsurface information to capture the degree of geologic heterogeneity in these regions. Improving the storage potential estimates for these provinces will require further characterization and testing to better understand the geology within the region. It is also of interest that the Michigan Basin and Colorado Plateau, both shallow shelf carbonate depositional systems, had very different results. The differences in porosity and permeability results between the two test sites may be explained by heterogeneities within these types of depositional systems or by differences in the development of secondary porosity and permeability by diagenetic or geomechanical processes. Results from one test within a depositional environment or a specific formation, whether successful or unsuccessful, cannot necessarily be considered predictive of results from other parts of the same formation or from similar formations in other locations. For this reason, further research and injection tests should be conducted to better understand heterogeneities, both in primary depositional environments and post-depositional processes, and how they influence the storage resources within saline formations.

Oil and gas formations offer great near-term potential for CO_2 storage, and the geologic conditions that trap oil and gas are also conducive to long-term geologic storage of CO_2 [5]. An added benefit of CO_2 injection in oil and gas formations is the potential for enhanced oil recovery (EOR) in which CO_2 injection may recover an additional 10-15 percent of the oil in place. The RCSPs have documented the locations of approximately 138 billion metric tons of Prospective Storage in oil reservoirs distributed over 27 states and three Canadian provinces [3][5]. While CO_2-based EOR has been practiced for over thirty years, additional effort will be needed to reconcile the conflicting goals of CCS and EOR and optimize both oil production and CO_2 storage [6] [7]. The RCSP's are conducting eight small-scale Validation Phase tests in oil and gas formations in five different depositional environments: deltaic, shelf clastics, shelf carbonates, reef, and fluvial (Table 2). Regardless of the injected volumes, formation thickness/characteristics, or depositional environment, all injection test sites successfully injected CO_2 and had associated oil production. The PCOR Zama test in the Alberta Basin is also testing the capability to inject a combination of CO_2 and H_2S into a carbonate reservoir, and is monitoring the effects on the injection zone, confining system, and produced hydrocarbon quality.

Table 2: Summary of geologic conditions at selected RCSP Validation Phase field tests injecting in oil and gas formations

Geologic Provinces	Injected Volume (CO_2)	Storage Formation (Thickness)	Perm (mD)	Avg Phi (%)	Depositional Environment	CO_2-EOR Activity
MGSC – Illinois Basin-Loudon Field	40 metric tons	Cypress Sandstone (80 feet)	15	15%	Delta Tidal Dominated (Clastics)	93 bbl produced
MGSC – Illinois Basin-Mumford Hills	2,850 metric tons	Clore Formation (10-40 feet)	155	19%	Fluvial Channel (Clastics)	4-8 times increase in current production rate
MGSC – Illinois Basin-Sugar Creek	5,850 metric tons	Jackson Sandstone (5-20 feet)	15	15%	Marine Shelf (Clastics)	2-3 times increase in current production rate
PCOR – Alberta Basin (Zama)	25,400 metric tons	Keg River Formation (400 feet)	100-1,000	10%	Pinnacle Reef (Carbonates)	25,000 bbl produced
PCOR – Williston Basin	400 metric tons	Mission Canyon Formation (14 feet)	0.35	15%	Shallow Shelf (Carbonates)	242 bbl produced
SECARB – Gulf Coast- Cranfield	627,744 metric tons	Tuscaloosa Formation (90 feet)	50-1,000	25%	Fluvial (Clastics)	NA
SWP – Paradox Basin	630,000 metric tons	Desert Creek and Ismay (200 feet total)	5-30	10%	Shallow Shelf Restricted (Carbonates)	~159,000 bbl produced
SWP – Permian Basin	86,000 metric tons	Cisco-Canyon (213 feet)	10-50	2-15%	Reef (Carbonate)	Increase from 575 to 2,000 bbl/day

Although all these tests have been successful, there is still some further investigation needed to understand controls on the CO_2 plume migration in these reservoirs. Initial indications from the SECARB Cranfield test are that plume migration is highly influenced by the stratigraphy within a depositional environment, i.e. fluvial channel. Because oil and gas formations typically have large amounts of existing data, including well-logs, core, production history, and seismic, there is sufficient subsurface information to support simulations and further research to predict, monitor, and understand plume migration and control.

A down side to this storage type, if there is one, is the potential difficulty of operating to optimize both oil production and CO_2 storage within the same formation. Because there is no current business case for sequestering CO_2 and no economic incentive to maximize CO_2 injection, whereas EOR operators seek to maximize incremental oil produced while minimizing the volume of CO_2 they must purchase for injection, these two coinciding efforts are usually conflicting. Even though CO_2-EOR has been ongoing for the past thirty years, additional research could be conducted to test the effects on oil production when CO_2 storage is optimized within various types of oil reservoirs.

Potential geologic storage in unmineable coal seams through adsorption processes is still considered a lower potential or unknown geologic storage type. This is because of the technical risks associated with swelling of the solid coal matrix during the adsorption process, resulting in reduced cleat aperture and overall permeability. However, similar to EOR in oil and gas formations, there is an added benefit to this storage type. The CO_2 injection into coal seams (either as a gas or as a supercritical fluid) results in sorption of CO_2 on organic-rich surfaces within the coal and, depending on the hydrostatic pressure, methane being liberated and produced while the CO_2 is retained [5]. CO_2 Prospective Storage resources in coal seams in North America are estimated between 157 – 178 billion metric tons [3] [5]. Five total unmineable coal seam tests have occurred at various injected volumes, seam thicknesses, and adsorption values as shown in Table 3 below.

Table 3: Summary of geologic conditions at selected RCSP Validation Phase field tests injecting in unmineable coal seams

Geologic Provinces	Injected Volume (CO_2)	Storage Formation (Thickness)	Avg Adsorption (scf/ton)	Avg Injection Rate (Day)	Results
MGSC – Illinois Basin	91 metric tons	Springfield Coal (7 feet)	1075 @390 psi	0.5-0.75 metric tons	Injection decreased then stabilized
PCOR – Williston Basin	90 metric tons	Fort Union (10 feet)	350 @350 psi	5.5 metric tons	Injection supports storage potential
SECARB – Black Warrior Basin	252 metric tons	Black Creek, Mary Lee, and Pratt (1-6 feet each)	600-900 @350psi	80 metric tons	Higher injectivity than expected
SECARB – Central Appalachian Basin	907 metric tons	Pocahontas & Lee (36 feet total)	300-750 @350psi	42 metric tons	Injectivity decreased to 20 metric tons per day
SWP – San Juan Basin	16,700 metric tons	Fruitland Coal Seams (60 feet total)	809 @ 317 psi 766 @ 260 psi 1038 @ 372 psi	46 metric tons	Lower injection rate than anticipated

The five Validation tests have demonstrated safe and effective CO_2 storage in coal seams; however, results in the Illinois Basin, Central Appalachian Basin, and San Juan Basin indicate lower-than-expected or reduced CO_2 injection rates over time. Again, the possible explanation for this is the effect of the swelling coal matrix over time. Laboratory investigations, small scale field tests, and numerical modelling results are encouraging, but currently results indicate that swelling can compromise the project performance and economics by having a fairly significant adverse impact on incremental methane recovery and long-term CO_2 injectivity [8]. The results have highlighted the need for additional research on the behavior of CO_2 in deep coal seams during injection to determine how to manage the effects of coal-swelling on a long-term injection. The ability to utilize this storage type, similar to EOR, will provide incentive to inject CO_2 into coal seams for geologic storage because of the potential to produce methane or natural gas, which has commercial value.

Basalt formations are geologic formations of solidified lava. Reaction with the minerals in basalts could potentially convert all of the injected CO_2 to a solid mineral form, isolating it from the atmosphere permanently. Basalt flows, such as those of the Columbia River Basalts in the Pacific Northwest, are believed to have a large potential for permanent CO_2 geologic storage. These flows are inter-layered, consisting of flow tops with high permeability (60-90mD) and porosity (15%), and flow interiors with low permeability and porosity. They are overlain by two suitable confining layers (Slack Canyon and Umtanum formations); however their sealing ability has yet to be demonstrated. The Big Sky Partnership is the only partnership conducting a pilot-scale injection of approximately 1,000 metric tons of supercritical CO_2 into a deep basalt formation (Grande Ronde Basalt) in western Walla Walla County in eastern Washington State. The test is assessing the mineralogical, geochemical, and hydrologic impact of injected CO_2 within a basalt formation and incorporating site MVA activities. Because this is the only basalt injection, additional understanding is still needed regarding CO_2 reactions in basalts, fundamental basalt geology (for example, distribution of breccias), and demonstration of large-scale confining layers.

The large-scale injection projects of the Development Phase involve at least one injection of approximately one million metric tons or more of CO_2 by each RCSP into regionally significant geologic formations of different depositional environments, focusing on saline formations. These large-volume injection tests are designed to demonstrate that CO_2 storage sites have the potential to store regional CO_2 emissions safely, permanently, and economically. The projects will progress through the Exploration Phase as described in the DOE Site Screening, Site Selection and Initial Characterization manual, but then will go through additional characterization processes in the Site Characterization Phase in preparation for the large-scale injection. The results of the characterization and injection processes should provide enough information to refine the regional storage resource estimates to a more specific site location storage resource estimate and to classify each site as “Contingent Storage Resource” [5]. Regional variations among the projects of the RCSPs will provide researchers with vitally important information and experience as they (1) test injection across a variety geologic settings; (2) engage shareholders and the public to provide education and insight into CCS activities; and (3) contribute to the development of permitting and other regulatory requirements that will be used for long-term injection and geologic storage of CO_2. These projects are considered the pre-cursors to commercial-scale major demonstration projects. As the knowledge gained though the

Validation Phase is incorporated in these Development Phase Projects, so the knowledge gained during this phase of the RCSP Initiative will be instrumental to future commercial-scale projects.

A total of nine tests are slated for the Development Phase, of which six project sites have already been selected, and the remaining three sites are being negotiated. Table 4 provides an overview of the six identified projects planning to inject into formations of four different types of depositional environments: fluvial, fluvial-deltaic, shallow shelf clastics, and barrier reef complex. The majority of these depositional environments are clastic-dominated, but one PCOR test in the Alberta Basin is testing a carbonate barrier reef complex. Although a good start to understanding depositional reservoirs, more work is needed in all the potential reservoir types. The Development Phase tests will further expand our understanding of these reservoirs, building on the knowledge gained through the Validation Phase tests in conjunction with previous research corroborated on injection and migration of other types of fluids in the subsurface [9], heterogeneities created by depositional environment and post-depositional processes that alter the initial porosity and permeability are important controls on the potential of all formation storage types to store CO_2.

Table 4: Summary of geologic conditions at selected RCSP Development Phase injection sites

Geologic Provinces	Proposed Injected Volume (CO_2)	Storage Formation	Depositional Environment	**Scheduled Injection	CO2 Source
MGSC – Illinois Basin	1,000,000 metric tons	Mt. Simon	Braided Fluvial (Clastics)	2011	ADM's Ethanol Production Facility
MRCSP – Michigan Basin	1,000,000 metric tons	St. Peter/ Bass Islands	Shallow Shelf Restricted (Clastics)	2011/2012	Natural Gas Processing Plant
PCOR – Alberta Basin	Up to 2,200,000 metric tons/yr	Elk Point Group	Barrier Reef Complex (Carbonates)	2012/2013	Spectra Energy Natural Gas Processing Plant
PCOR – Powder River Basin	1,000,000 metric tons/yr	Cretaceous Muddy Formation	Fluvial Deltaic (Clastics)	2013/2014	Conoco Phillips Lost Cabin/Madden Natural Gas Processing Plant
SECARB – Gulf Coast	1,500,000 metric tons	Lower Tuscaloosa	Fluvial Deltaic (Clastics)	Injecting >1,000,000 metric tons	Jackson Dome (Natural Source)
SECARB – Gulf Coast	300,000 metric tons	Paluxy Formation	Fluvial Deltaic (Clastics)	2011/2012	Southern Company's Plant Barry Coal Fired Power Plant

** Injection dates are subject to change and the dates above reflect those currently current planned

In addition to the various depositional environments being tested, the RCSP Initiative's Development Phase projects are also exploring the issues with utilization of a variety of CO_2 sources including naturally occurring, ethanol facilities, natural gas processing plants, and capture from power plants [3]. Using CO_2 from a variety of sources across Partnership tests provides insight into the required infrastructure, costs, and overall level of effort needed to capture and safely store CO_2 from a particular source type. Tests are designed to not only investigate commercial-scale injection of CO_2, but will also be used to understand the necessary regulatory and public outreach efforts needed for successful CCS, and to develop the necessary human capital, knowledge base, and experience necessary to implement future CCS operations.

In conclusion, the Regional Partnership Initiative has completed almost all of the planned Validation Phase and is in the process of initiating the nine Development Phase project tests assessing various CO_2 sources, storage types and target formations of different depositional environments. Each of the storage types being assessed, saline, oil and gas formations, unmineable coal seams, and basalts, has allowed the Partnerships to make great strides towards understanding the advantages and challenges of geologic storage in each storage type and to elucidate for each, a set of future research needs. These include future tests and larger research projects to: (1) improve and refine regional Prospective Storage resource estimates for each storage type throughout North America; (2) understand the complexities of the subsurface which affect potential injectivity and plume migration, including depositional environments and post-depositional processes (e.g., diagenetic, structural); (3) address fundamental research issues, such as accurate prediction of long-term migration and stabilization of plumes, long-term reactivity of CO_2 with fluids and minerals in the subsurface (e.g., swelling of coal seams, basalt reactivity and permanency of storage in all rock types through mineralization reactions); and (4) inform regulators, policymakers, and the public about the issues associated with deployment of commercial-scale CCS. It is through all these integrated efforts that technically sound assessments of the subsurface could ensure safe and permanent geologic storage of CO_2.

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