

SECARB

Southeast Regional Carbon Sequestration Partnership (SECARB) Gulf Coast Stacked Storage Project

Field Test Location

Cranfield Oilfield, Mississippi

Amount and Sources of CO₂

1,300,000 Tons (as of
December 1, 2010) from
Natural Source (Jackson
Dome)

Primary Contacts

DOE/NETL Project Manager

Mr. Bruce Lani
bruce.lani@doe.netl.gov

Principal Investigator

Mr. Kenneth J. Nemeth
Southern States Energy
Board (SSEB)
nemeth@sseb.org

Field Test Site Contact

Dr. Susan Hovorka
Gulf Coast Carbon Center,
Bureau of Economic
Geology
Jackson School of
Geosciences
The University of Texas at
Austin
susan.hovorka@beg.utexas.edu
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Field Test Partners

Primary Sponsors

DOE/NETL
SSEB
The University of Texas at
Austin

Industrial Partners

Denbury Onshore LLC
Sandia Technologies
Schlumberger CO₂

Summary of Field Test Site and Operations

The Southeast Regional Carbon Sequestration Partnership's (SECARB) Gulf Coast Stacked Storage Project demonstrates the concept of phased use of subsurface volumes, combining early use of carbon dioxide (CO₂) for enhanced oil recovery (EOR) with later injection into deeper and larger volume brine formations. Technical focus areas are: (1) documenting retention in the injection zone; (2) quantifying capacity; and (3) quantifying pressure response to injection. The Cranfield unit in southwest Mississippi operated by Denbury Onshore LLC is the site of this test. The Gulf Coast Carbon Center (GCCC) at the University of Texas-Austin's Bureau of Economic Geology (BEG) leads the Cranfield stacked storage project.

The Gulf Coast of Alabama, Mississippi, Louisiana, and Texas is formed by the thickest sedimentary wedge in the onshore United States. This clastic sequence is comprised of late Mesozoic to Cenozoic age formations composed of porous and permeable fluvial, deltaic, shoreline, and marine sandstones, separated by regionally extensive thick impermeable marine and non-marine mudrocks that isolate fluids. Further compartmentalization and isolation of storage volumes throughout the Gulf Coast is provided by structures, which include anticlinal four-way closures, roll-over anticlines, and fault bounded traps.

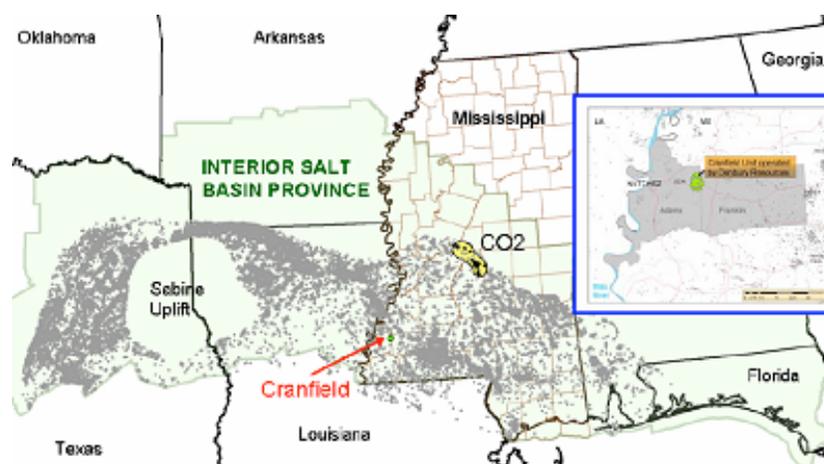


Figure 1. Geographical location of SECARB Phase II study at the Cranfield Field east of Natchez, Mississippi

The permanence of storage in these formations is well documented by oil and gas that has been trapped for long time periods. Representative world-class sequestration target formations in the Gulf Coast are the Cretaceous Tuscaloosa Formation of the Mississippi salt basin and the equivalent Woodbine Formation of the East Texas Basin, Cenozoic age Wilcox and Vicksburg/Frio formations, and Miocene formations of the lower Gulf Coast. The Tuscaloosa Formation lies beneath an area of approximately 46,000 square miles in southern Alabama and Mississippi, the Florida Panhandle, and

Using NATCARB 2008 assumptions, Massachusetts Institute of Technology (MIT) has estimated a minimum storage volume for the Tuscaloosa Formation of 14,000 million metric tonnes of CO₂. The Woodbine of East Texas, a continuation of this regionally significant CO₂ sink, can hold approximately equivalent volumes. Additional storage in the Gulf Coast Cenozoic reservoirs, expanded in 2008 to include offshore, is estimated to be more than 2,000 billion metric tonnes. Data from the Tuscaloosa trend can also help provide improved capacity estimates for the Cretaceous of the eastern seaboard, which presents the best target for this area, totaling an additional 134,000 million metric tonnes of CO₂.

The sequestration target tested for the Gulf Coast Stacked Storage Project is within and associated with Denbury's Cranfield unit (Figure 1), east of Natchez, Mississippi. The injection target was selected to be representative of the high quality targets provided by the Gulf Coast, in that it lies within the thick marine-reworked to fluvial lower sandstone of the Tuscaloosa Formation in a typical Gulf Coast four-way closure (Figure 2). This test site was selected at a location where large volumes of pipeline CO₂ are available since July 2008 and where existing infrastructure and substantial industry match allowed the field investigation to be cr

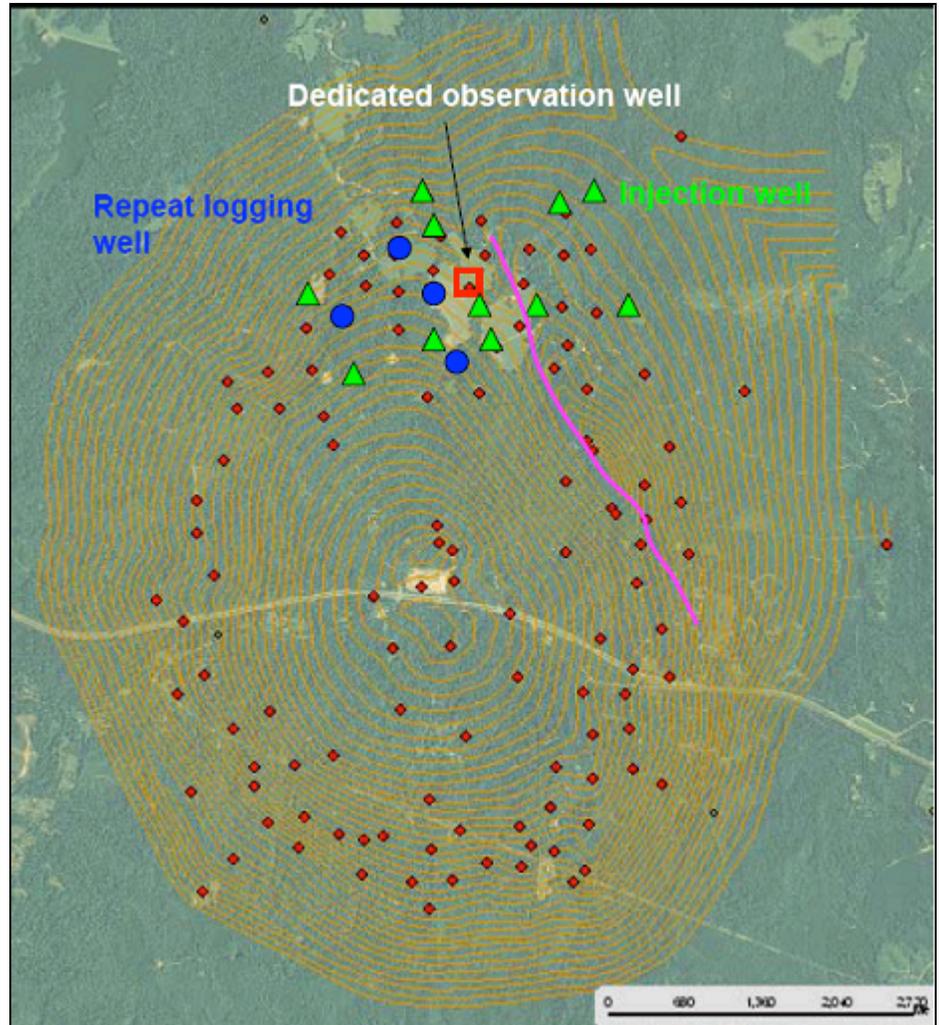


Figure 2. Injection target for the Stacked Storage Project lies within the thick marine-reworked to fluvial lower sandstone of the Tuscaloosa Formation in a typical Gulf Coast four-way closure

Research Objectives

Phased Use of Subsurface Volume

The stacked storage concept is based on the following assessment: Where large volume oil fields in decline exist in a region, market forces will determine that initial anthropogenic carbon capture will supply CO₂ for enhanced oil recovery (CO₂-EOR). As the CO₂ demand for EOR decreases over decades and volumes of CO₂ captured increase, brine storage will become widely utilized. Existing and developed pipeline infrastructure and a favorable geologic setting will favor continued injection in the same geologic trends that hosted EOR resources. Lack of cement behind casing in EOR production wells may limit the use of horizons shallower than the EOR interval for brine storage. However, injection into brine-bearing formations below and adjacent to former production may prove to be attractive targets. Deeper formations

in the same footprint as oil production have attractive characteristics in that they are geologically well known, have well-defined surface and mineral ownership, and public acceptance of subsurface activities is high.

Key information needed to demonstrate the validity of this model are: (1) will CO₂ used for EOR be retained in the subsurface effectively so that benefit to the atmosphere is produced, especially considering the impact of well penetrations; (2) how should the capacity in large volumes below and downdip of the reservoirs be calculated, as this will determine how large a footprint will be underlain by CO₂; and (3) is the pressure response in the near and far field understood quantitatively well enough to safely move to large volume injection?

GCCC has partnered with Denbury Onshore LLC of Plano, Texas, to begin to answer these questions under realistic conditions associated with large volume injection (> 1 million tons per year CO₂). The CO₂ injection design used by Denbury is identical to that which would be used for large volume storage in that CO₂ is injected continuously, so that the CO₂ injection volume and field pressure is high as compared to the West Texas process of injection of water alternating with gas (WAG). The Cranfield oil field was depleted in the mid-1960's and wells plugged and abandoned (P&A), so that the field has had more than 40 years to re-equilibrate. Over this time, pressure has recovered to near original pre-production pressure because of water incursion. Denbury has redeveloped the field to produce remaining oil with CO₂-EOR, with injection starting July 2008. Denbury produces by gas lift so that the initial part of the test period did not have production identical to storage -only.

The Denbury pipeline network extends across Mississippi, Louisiana, and Texas is supplied by the Jackson Dome, a naturally occurring subsurface source of CO₂. Denbury's development plan calls for the incorporation of anthropogenic CO₂ into the pipeline network. Ultimately this pipeline network has potential to connect depleted reservoirs and large volume brine storage to sequester anthropogenic CO₂ produced throughout the region.

Plan Implementation

Detailed characterization of the field, the foundation of both good flood design and successful monitoring strategy, was completed in the spring of 2008 by Denbury and GCCC. Two hundred 1940's vintage wireline logs provide stratigraphic and structural data; several hundred sidewall cores plugs and detailed field production records provide information on fluid flow. New characterization data contributed by Denbury includes a 3-D seismic survey and data from ten new wells including open-hole logs, whole cores from two wells, and side wall cores from two others have been provided to GCCC as matching data. Stratal slicing of the seismic volume to assess storage volume interconnectivity has been completed, as well as assessment of new and existing cores to evaluate seal and monitoring intervals. Further characterization was completed as part of Phase III.

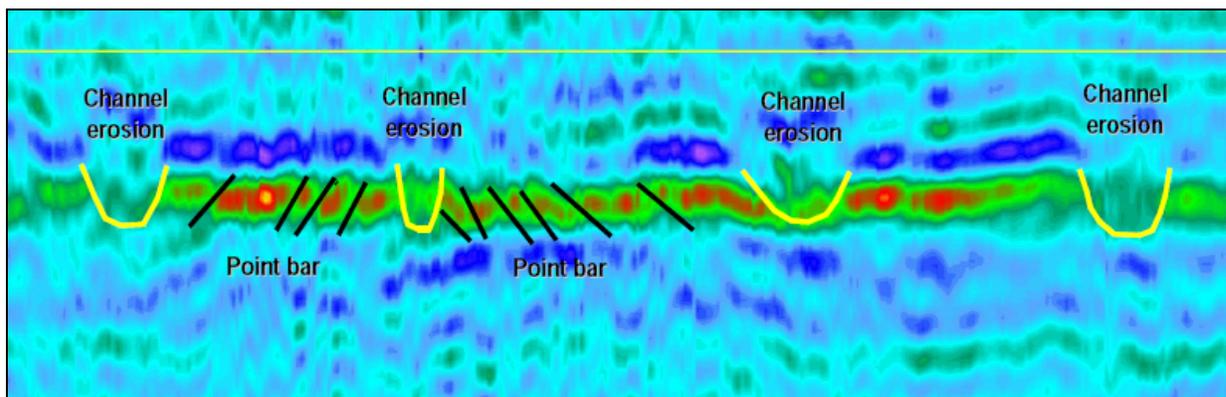


Figure 3. Stratal slicing and high resolution processing (Hongliu Zeng) shows an interpretation of the complexity within a fairly continuous lower Tuscaloosa sand body.

The lower Tuscaloosa injection zone at Cranfield is a highly heterogeneous complex of fluvial channel sandstones and conglomerates (Figure 3). Basal Tuscaloosa conglomerates (unit E) are incised into marine shales and silts of the Washita-Fredericksburg Group; overlying lithic arkoses are poorly sorted and show sinuous patterns with amalgamated cross-bedded and point bar deposits forming a fairly continuous sand-rich zone across the field (unit D). Calcite and Fe-chlorite cements further complicate the flow system developed in these rocks. Red overbank mudstones serve as seals on the oil-producing interval. Overlying fluvial sandstones (A through C) show more strongly aggradational characteristics in that they are not amalgamated and form more discontinuous sand-rich horizons across the field.

The SECARB monitoring program for Phase II Stacked Storage at Cranfield began in the spring of 2008 prior to CO₂ injection and continues as part of Phase III. A novel test element is a dual completed observation well to allow monitoring pressure in two zones: the lower Tuscaloosa injection zone and an aerielly continuous, 12 ft thick, 100 md sandstone above the thick middle Tuscaloosa mudstone that serves as an above-zone monitoring interval (AZMI). This test assessed the adequacy of established Mississippi well integrity standards for retaining CO₂ for greenhouse gas mitigation. Modeling shows that, should significant leakage occur through the reservoir seal through preferred conduits such as flawed well completions or faults in the area, pressure would increase in the monitoring zone. A plugged and abandoned former production well, the Ella G. Lees #7, was reentered and repaired to serve as a dedicated observation well prior to the start of injection. Pressure and temperature data from both the injection zone and AZMI are transmitted via wireline to a satellite uplink, providing real-time access to 10 minute data, with higher frequency data stored at the well site. Over 2 1/2 years, pressure in the injection zone increased as much as 1200 psi. Pressure measurement at an idle well completed in the injection zone proved to be an effective tool for injection surveillance. Pressure at the observation well responded rapidly and with high sensitivity to injection and shut-in at distant wells documenting hydrologic continuity of the reservoir, as well as the corroborating effective cross-fault sealing performance predicted on the basis of production history of one of the crestal graben-bounding faults. Slow onset of production by natural lift was more difficult to separate from response due to reservoir heterogeneity. Additional monitoring undertaken to constrain the model and thereby document the capacity under the conditions at the site includes intermittent flowing and shut in pressure measurements at selected producers using memory gauges, selected injection and production profiles, and wireline behind-casing estimates of fluid changes measured with Schlumberger's Reservoir Saturation Tool (RST) at selected observation wells. Change in well-head pressure because of lower fluid column density was effective in documenting arrival of CO₂ at the observation well where breakthrough of CO₂ occurred in 2010, about a year later than predicted by modeling.

Pressure changes in the AZMI showed a more complex response than predicted, but document that the AZMI is mostly isolated from the injection zone. A slight decrease at the start of injection, followed by an increase (Figure 4) is attributed to a combination of near-well bore effects, geomechanical effects, and minor fluid migration along well completions. It is difficult to isolate the effects of these similarly-trending processes. In future projects we plan to reduce complexity by installing single-use AZMI wells to reduce the near-well bore effects. At project end, fluid sampling to test the AZMI for geochemical evidence of leakage is planned.

A soil gas and groundwater program to assess the value of such monitoring at the Cranfield site is underway and continues as part of Phase III. No anomalies attributed to CO₂ leakage have been observed.

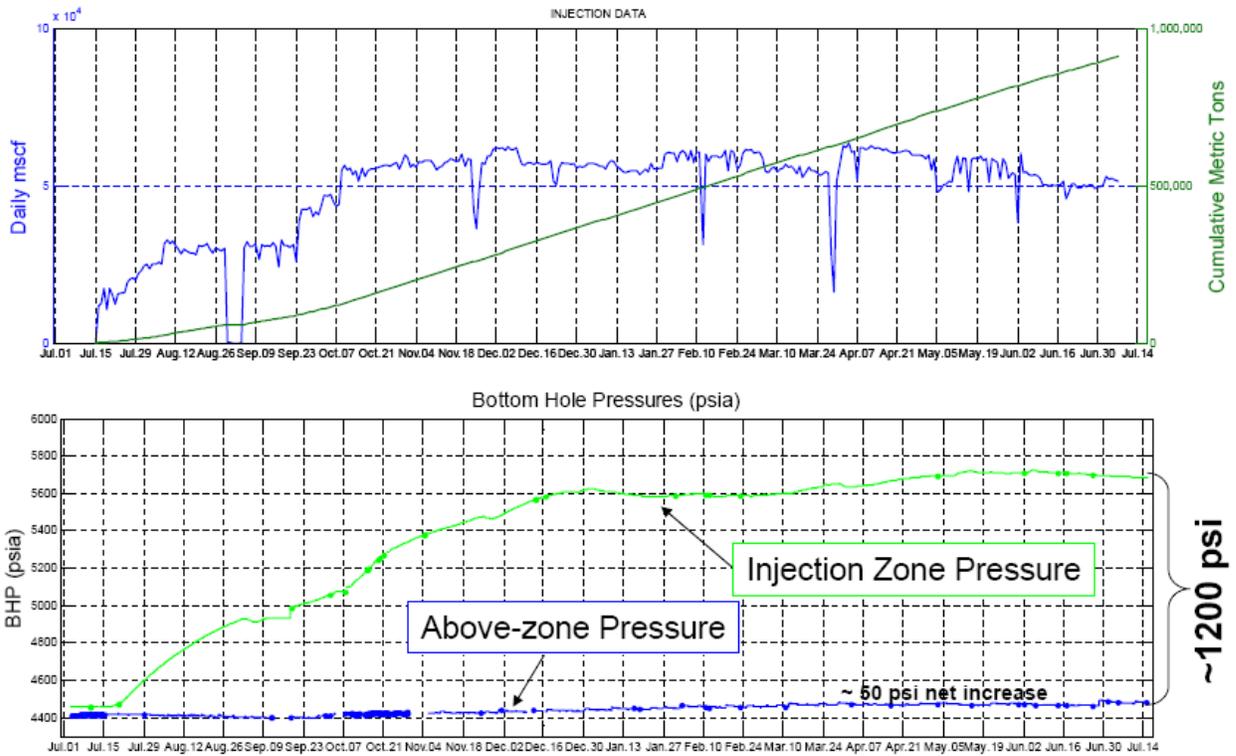


Figure 4. One year record of injection and corresponding pressure increase in the injection zone is not matched by corresponding pressure increase in the overlying monitoring zone shows the degree of isolation in an area with numerous wells.

Regional Significance

The economic engine that can help power the initial deployment of carbon capture and sequestration (CCS) technology is CO₂-based enhanced oil recovery. However, to use this technology to support CCS, it is important to document how well CO₂ is retained in an area with numerous existing well penetrations. This test will provide the first quantitative field test of well integrity across many wells. It complements the Southwest Regional Sequestration Partnership test at SACROC where CO₂ has been injected over decades.

The Bureau of Economic Geology has made a conservative estimate that over 5 billion barrels of oil are recoverable by CO₂ EOR in the target area of east Texas, Louisiana, Mississippi and Alabama. This activity can pay for the CCS equipment, regional CO₂ pipelines, and compression facilities that can also be used for putting CO₂ into long term storage in deep brine reservoirs in the Gulf Coast. Preliminary economic modeling by the BEG and the Massachusetts Institute of Technology (MIT) support the conclusion that such regional pipeline complexes linking many sources and sinks are more efficient than single pipelines linking individual sources and sinks. Such regional pipelines also allow matching capture and injection rates across multiple sites to reduce risk.

The Gulf Coast region contains more than 3,000 oil and natural gas reservoirs that could be used first for EOR and then for large-volume, long-term storage of CO₂ in nonproductive formations below the reservoir interval. Many oil reservoirs have at least one deeper brine aquifer that could be accessed by drilling deeper sequestration injection wells from existing field footprint.

<p>Cost</p> <p>Total Field Project Cost: <u>\$7,790,649</u></p> <p>DOE Share: <u>\$4,634,562 59%</u></p> <p>Non-DOE Share: <u>\$3,156,087 41%</u></p>	<p>Field Project Key Dates</p> <p>Characterization Completed: Q1, FY08</p> <p>Workover Operations Completed: Q2, FY08</p> <p>Injection Operations Began: Q3, FY08</p> <p>MVA Events:</p> <p style="padding-left: 20px;">Pre-injection baseline completed: Q2, FY08</p> <p style="padding-left: 20px;">One year injection monitored : Q2, FY09</p> <p style="padding-left: 20px;">Injection monitoring continues: Q1, FY10</p>
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Tasks	FY2006				FY2007				FY2008				FY2009				FY2010			
	Q1	Q2	Q3	Q4																
1.1 Project Definition	█	█	█	█	█	█	█	█	█	█	█	█	█	█	█	█	█			
1.2 Design			█	█	█	█	█	█												
1.3 Implementation									█	█	█	█								
1.4 Operations													█	█	█	█	█	█	█	█
1.5 Closeout/Reporting																█			█	█

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