Commercial Scale CO$_2$ Injection and Optimization of Storage Capacity in the Southeastern United States

Project Number: DE-FE0010554

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Advanced Resources International
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Presentation Outline

• Benefit to the Program
• Project Overview
• Technical Status
• Accomplishments to Date
• Summary
• Appendix
  – Organization Chart
  – Gantt Chart
  – Bibliography
The project will model **commercial-scale CO$_2$ storage capacity** optimization strategies to effectively manage the CO$_2$ plume and pressure field **within stacked reservoir systems**. These strategies will utilize geologic and performance data collected from SECARB’s Anthropogenic Test Site, and will be high-graded based on cost and storage efficiency, considering reservoir geomechanics (pressure field) and laboratory-derived cap rock data.

**Major advances:**

- Estimating commercial scale storage efficiency factors (*Support industry’s ability to predict CO$_2$ storage capacity in geologic formations to within ±30 percent*)
- Detailed confining unit core characterization
- Generation of reduced order models
- Stacked Reservoir System Best Practices Manual
Project Objectives

- Optimize capacity and ensure storage containment in stacked Gulf Coast saline and oil bearing reservoirs
- Leverage modern and historical geologic characterization and injection performance data to develop detailed geologic models
- Overlay economic and risk management scenarios for each simulation case to determine the overall feasibility of commercial scale storage.
- Conduct detailed cap rock core analysis testing
- Develop new storage efficiency factors based on these project results
- Develop reduced order models to approximate the ‘super computer’ results
- Summarize the results in a Best Practices Manual
Project Status: Study Area & Well Data Set

- 400+ total wells in Citronelle Field on 40-ac spacing
- Study area for geologic model = 56 sq. miles
- Geologic model characterizes injection zones and confining units from surface though the Donovan sandstones at depths >12,000 ft.
- D 9-8 #2 well in Citronelle Southeast Unit selected as Type Log for geologic correlations of injection zones & confining units.
- Multiple cross-sections constructed for geologic correlation of model layers.
- Digitized the SP & resistivity curves for 36 well logs. These data input to neural net software to estimate porosity.
Project Status: Building the Geologic Model

- Potential storage and confining layers were identified and correlated laterally.
- Structural closure is present at all horizons from surface through the Donovan (Rodessa) sandstone.
Extrapolated Continuity of Upper Paluxy Sandstones & Confining Units At Citronelle Southeast Unit NW – SE Example
Porosity Prediction

- Most of the legacy wells have resistivity logs only and no porosity logs.
- 3 new wells with modern porosity logs were drilled on well pads with existing abandoned wells.
- These paired wells offer a unique opportunity for using a neural network approach to predict porosity.
Porosity Prediction Results

• Porosity predicted from Neural Net for D-9-9 #1 compared to actual density porosity from D-9-9 #2 well.

• Average porosity values for selected Upper Paluxy sandstones are shown.

• Average porosity values for Paluxy sandstones for “predicted” and “actual” are very close.

• Larger range between min and max values and finer vertical resolution for actual porosity than for “predicted” porosity.
Upper Paluxy Permeability Prediction

- 60 Model Layers
- Three whole cores from the injection and observation wells, SECARB Phase III Anthropogenic Test at Citronelle Field
- Porosity range: 4.4% - 26.1%;
- Max permeability of 145 samples = 4,020 mD
- Mean porosity = 16.3%
- Mean $k_{\text{air}} = 373.9$ mD (arithmetic)
- Mean $k_{\text{air}} = 19.3$ mD (geometric)

Examples of Predicted Permeability for Upper Paluxy

<table>
<thead>
<tr>
<th>Core Porosity, %</th>
<th>Upper Paluxy</th>
<th>Core Porosity, %</th>
<th>Upper Paluxy</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Core Permeability, mD</td>
<td></td>
<td>Core Permeability, mD</td>
</tr>
<tr>
<td>6</td>
<td>0.004</td>
<td>24</td>
<td>1,186.7</td>
</tr>
<tr>
<td>8</td>
<td>0.058</td>
<td>26</td>
<td>2,446.1</td>
</tr>
<tr>
<td>12</td>
<td>2.26</td>
<td>28</td>
<td>4,778.6</td>
</tr>
<tr>
<td>16</td>
<td>30.4</td>
<td>30</td>
<td></td>
</tr>
<tr>
<td>20</td>
<td>228.5</td>
<td>32</td>
<td></td>
</tr>
<tr>
<td>22</td>
<td>540.6</td>
<td>34</td>
<td></td>
</tr>
</tbody>
</table>
Porosity and Permeability Extrapolated for Each Model Layer

- **Tertiary/Quaternary Model Layers (Midway-Surface):**
  - Predicted porosity from neural net not successful due poor log data quality/missing data.
  - A single porosity and permeability value applied for each model layer over the entire study area.

- **Cretaceous Model Layers (Donovan to Selma):**
  - Apply geostatistics to interpolate predicted porosity.
  - Apply porosity-permeability transforms from core data to extrapolate reservoir permeability from predicted porosity.

<table>
<thead>
<tr>
<th>Formation</th>
<th># Model Layers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alluvium</td>
<td>1</td>
</tr>
<tr>
<td>Citronelle</td>
<td>1</td>
</tr>
<tr>
<td>Miocene</td>
<td>1</td>
</tr>
<tr>
<td>Chickasawhay</td>
<td>1</td>
</tr>
<tr>
<td>Vicksburg</td>
<td>1</td>
</tr>
<tr>
<td>Jackson</td>
<td>1</td>
</tr>
<tr>
<td>Claiborne</td>
<td>3</td>
</tr>
<tr>
<td>Wilcox</td>
<td>5</td>
</tr>
<tr>
<td>Midway</td>
<td>5</td>
</tr>
<tr>
<td>Selma</td>
<td>20</td>
</tr>
<tr>
<td>Eutaw</td>
<td>20</td>
</tr>
<tr>
<td>Upper Tuscaloosa</td>
<td>50</td>
</tr>
<tr>
<td>Tuscaloosa Marine Shale</td>
<td>10</td>
</tr>
<tr>
<td>Lower Tuscaloosa</td>
<td>30</td>
</tr>
<tr>
<td>Washita</td>
<td>60</td>
</tr>
<tr>
<td>Fredericksburg</td>
<td>60</td>
</tr>
<tr>
<td>KWF Confining</td>
<td>5</td>
</tr>
<tr>
<td>Upper Paluxy</td>
<td>60</td>
</tr>
<tr>
<td>Lower Paluxy</td>
<td>20</td>
</tr>
<tr>
<td>Mooringsport</td>
<td>5</td>
</tr>
<tr>
<td>Ferry Lake Anhydrite</td>
<td>1</td>
</tr>
<tr>
<td>Donovan</td>
<td>40</td>
</tr>
</tbody>
</table>
Heterogeneity Modeling

- Heterogeneity was modeled over the study area using geostatistics.
  - Generating realizations was tedious
  - (least squares) Kriging methods within *Petra* approximated geostatistics.

Porosity Interpolation for the Paluxy (Layer 7)

Letter markings on the maps highlight the corresponding low and high porosity regions that are spatially and morphologically similar.
Heterogeneity Modeling

- Moving forward, *Petra* (Kriging) was used to generate the heterogeneity cases for each layer, proving more flexible and efficient.

<table>
<thead>
<tr>
<th>Heterogeneity Scenario</th>
<th>Surface Style Contouring</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case</td>
<td>Highly connected features</td>
</tr>
<tr>
<td>Low Heterogeneity</td>
<td>Minimum Curvature</td>
</tr>
<tr>
<td>High Heterogeneity</td>
<td>Disconnected Features</td>
</tr>
</tbody>
</table>

Upper Paluxy layer 7
Laboratory Results
Confining Layer in the Paluxy Formation, Citronelle Field

Absolute permeability of Sample 2FD from the SECARB Phase III Anthropogenic Test.

Core from Well D-9-9 #2, 9431.3 ft depth.

<table>
<thead>
<tr>
<th>Pressure (MPa$^{-1}$)</th>
<th>Permeability (microdarcy)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.5</td>
<td>2.95 +/- 0.03 microdarcy</td>
</tr>
</tbody>
</table>

ARI Sample No. 2FD
Citronelle Field
Well D-9-9 #2
9431.3 ft depth
Carbon Dioxide
Determination of Minimum Capillary Displacement Pressure*†

Sample from the SECARB Phase III Anthropogenic Test, Paluxy Formation, Citronelle Field.

Plug 25 mm in diameter by 27 mm long. Single-phase permeability, 3 microdarcy.

Decay of a pressure pulse imposed across the plug, initially saturated with brine. Upstream pressure, 815 psig.

Upstream-downstream pressure difference approaches an asymptotic value equal to the capillary pressure at the narrowest throat in the highest conductivity pore.

Determines the “minimum capillary displacement pressure,” at which gas would break through brine-saturated rock, given enough time.

Provides a better estimate of breakthrough pressure than obtained by increasing the upstream pressure until gas appears at the downstream face.

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Effective Permeability*†

During the approach to the minimum capillary displacement pressure, the effective permeability to the gas phase can be obtained from the derivative of the downstream pressure with respect to time.

The effective permeability first increases, as brine drains and gas phase saturation increases, then decreases as brine returns, closing off open pores, from smallest to largest.

The maximum effective permeability, 0.09 to 0.10 microdarcy, ~ 1/30th of the absolute permeability, determines the maximum gas flow rate through a confining layer following breakthrough.

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Effective Permeability vs. Pressure

Dependence of the effective permeability of the brine-saturated plug on upstream to downstream pressure difference, following breakthrough.

The minimum capillary displacement pressure, $P_d$ (1.2 MPa, 174 psi) is the pressure at breakthrough, on the left.

The effective permeability varies from 0 at the minimum capillary displacement pressure to a maximum of 0.09 to 0.10 microdarcy at $P_{\text{max}} = 3.55$ MPa (515 psi), at the minimum brine saturation and maximum gas saturation.

The dependence of the effective permeability on pressure, above the minimum capillary displacement pressure, can be described by:

$$\frac{k_{\text{eff}}}{k_{\text{eff, max}}} = 1 - \left( \frac{P_{\text{max}} - P}{P_{\text{max}} - P_d} \right)^4 \quad P_d \leq P \leq P_{\text{max}}$$

The effective permeability is expected to remain at its maximum value, $k_{\text{eff, max}}$, with further increase in excess gas pressure above $P_{\text{max}}$.

The "excess pressure" in the laboratory set-up is the upstream to downstream pressure difference across the plug. In the field it would be the difference between the pressure in stored CO$_2$ at the interface with a confining layer and the local hydrostatic pressure.
Size Distribution of Conducting Pores Derived from the Dependence of Effective Permeability on Pressure

Dependence of effective permeability on pressure:

\[ \frac{k_{eff}}{k_{eff,max}} = 1 - \left( \frac{P_{max}-P}{P_{max}-P_d} \right)^4 \]  
(1)

Relationship between pore radius and capillary pressure:

\[ P_{capillary} = \frac{2 \gamma \cos \theta}{r} \]  
(2)

Washburn (1921).

Rate of change of porosity, \( \phi \), with increase in radius, \( r \), of \( N \) parallel monosize pores:

\[ \frac{d\phi}{dr} = \frac{8}{r^2} \frac{dk}{dr} \]  
(3)

Hildenbrand et al., Geofluids, (2002) 2, 3-23.

Substitute Eq. (2) into Eq. (1), then differentiate Eq. (1) with respect to \( r \), and substitute the result into Eq. (3).

Volume-based size distribution of conducting pores.

Area under the curve = transport porosity \( \approx 0.015\% \)
Injected CO₂ is treated as a simple column having uniform cross section and depth.

Rate of CO₂ storage (mass per unit time per unit plan area) = injection rate – leakage rate.

Excess pressure at the confining layer/reservoir interface = (density brine - density CO₂) × g × height of CO₂ column

Leakage begins when the excess pressure exceeds the minimum capillary displacement pressure.

The dependence of effective permeability on excess pressure, following breakthrough, is described by the equation fit to the measurements.

CO₂ is injected at a rate of 500 metric tons/day for 40 years into wells on 40-acre centers.

Breakthrough occurs 29 years after the start of CO₂ injection.

For confining layers thicker than about 5 m, >99% of CO₂ is retained at 100 years.

Porosity of the storage reservoir: 19%
Minimum capillary displacement pressure: 174 psi
CO₂ column height at breakthrough: 273 m
Maximum permeability of the confining layer: \( k_{\text{eff, max}} = 0.095 \text{ microdarcy at 515 psi} \)
Reservoir Sandstone

Cross-beds

Ripple cross-laminae

Meniscate burrows
(insects and other soil dwellers)

Core width = 10 cm
Geological Highlights

- Reservoir: Multistorey bedload-dominated fluvial deposits.
- Baffles, barriers, and seals: Interfluvial mudstone with caliche.
- Sandstone is very fine- to coarse-grained subarkose and arkose.
- Diagenesis reflects dominant influence of soil development.
- Grain dissolution, quartz overgrowth, illuvial clay coating, carbonate cement influence reservoir quality.
- Reservoir porosity commonly >20%.
- Permeability up to 3.8 Darcies.

Similar deposits are widespread in Lower Cretaceous of Gulf of Mexico region.
Accomplishments to Date

• Completed geologic model
• Successful implementation of the Neural Network approach to predict porosity
• Generated low, base and high heterogeneity cases
• Completed simulation models, handed over to UAB for testing, debugging and execution
• Laboratory measurements/estimates of
  • effective permeability,
  • minimum capillary displacement pressure, and
  • leakage impact
• OSU is underway with Paluxy core, petrographic and x-ray diffraction
Key Findings/ Lessons Learned

• The Project Team is able to successfully characterize a subsurface volume of $1.9 \times 10^{13}$ ft$^3$ for reservoir simulation ($56$ square miles x $12,000$ vertical feet), by combining legacy geophysical log data with modern log data, core data, and state of the art interpretive tools like neural net and geostatistics software.

• Neural network tools were extremely effective in “modernizing” the vintage geophysical well logs to ascertain spatial variations in porosity and, by proxy, permeability.

• Kriging, in lieu of full geostatistical analyses may greatly improve the workflow of the project when reviewing heterogeneity variability.

• Effective permeability through brine-filled confining units appear to be on the order of $1/30^{th}$ of the absolute permeability.

• CO$_2$ containment through significantly thick and low permeability confining units appears to be $>99\%$, based on Paluxy data.
Future Plans

- **Sensitivity Study**: Will explore sensitivities such as well design and lateral heterogeneity to maximize storage capacity while minimizing the operation’s footprint.

- **Optimization**: Will incorporate economic and risk management considerations which will be overlain on the modeling results to ascertain their financial impact.

- **Cap Rock Analysis**: Caprock analysis will provide regional seal characteristic data to be used in numerical modeling.

- **New Storage Efficiency Factors**: Will develop new commercial storage efficiency factors.

- **Screening Models**: Will develop simplified screening models to cost effectively identify potential commercial storage sites.

- **Scoping Level Models**: Will develop a scoping level model to provide baseline storage capacity and injectivity and estimate ground deformation, plume extent and pressure build-up.

Appendix: Organization Chart

US DOE/NETL Product Office

Advanced Resources International

G. Koperna
Project Director and Principal Investigator

Task 1.0
Project Management and Reporting

ARI

Task 2.0
Gather and Characterize Regional Geologic Info

ARI

Task 3.0
Construct Geologic Models

ARI

Task 4.0
Upscale Geologic Model for Reservoir Simulation

ARI

Task 5.0
Model Sensitivity Study

Southern Company
ARI
UAB

Task 6.0
Development of Reduced Order Models

ARI
Southern Company
UAB

Task 7.0
Economics and Risk Management

ARI

Task 8.0
UAB Caprock Experiments

UAB
Appendix: Gantt Chart
Appendix: Bibliography

