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

11:15am, Thursday, August 14, 2014

U.S. Department of Energy
National Energy Technology Laboratory
Carbon Storage R&D Project Review Meeting
Developing the Technologies and Infrastructure for CCS
August 12-14, 2014

Presentation Outline

- Benefit to the Program
- Project Overview
- Technical Status
- Accomplishments to Date
- Summary
- Appendix
  - Organization Chart
  - Gantt Chart
  - Bibliography

Benefits Statement

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

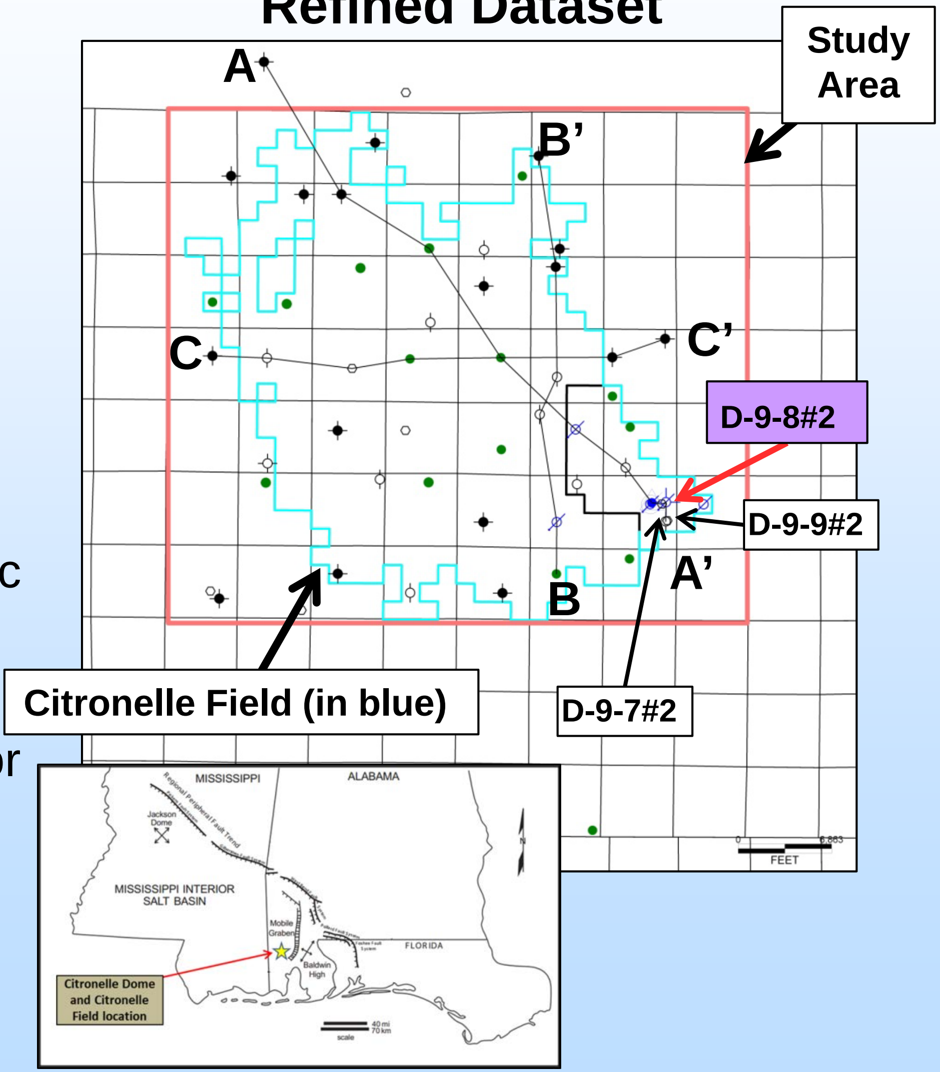
Project Objectives

- 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

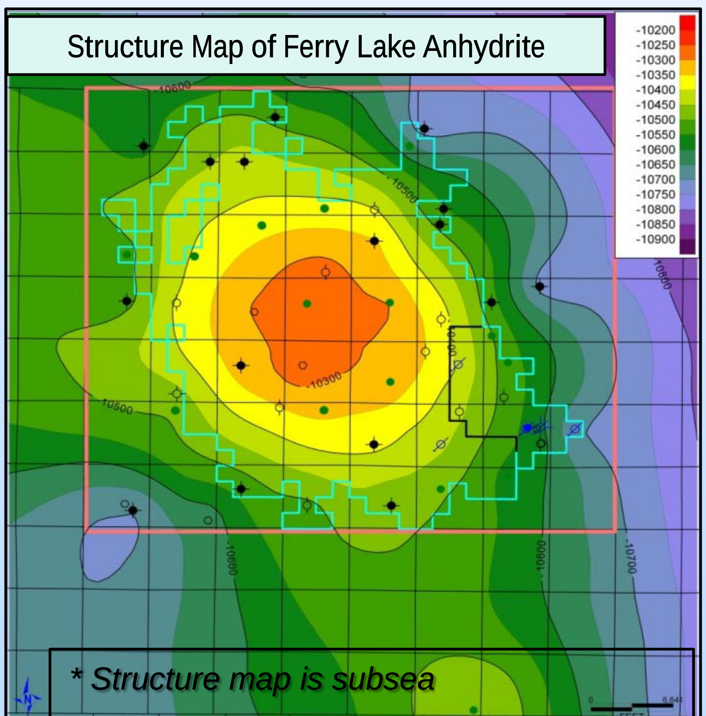
- 400+ total wells in Citronelle Field on 40-ac spacing
- Study area for geologic model = 56 sq. miles
- Geologic model characterizes injection zones and confining units from surface though the Donovan sandstones at depths >12,000 ft.
- D 9-8 #2 well in Citronelle Southeast Unit selected as Type Log 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.

Refined Dataset



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

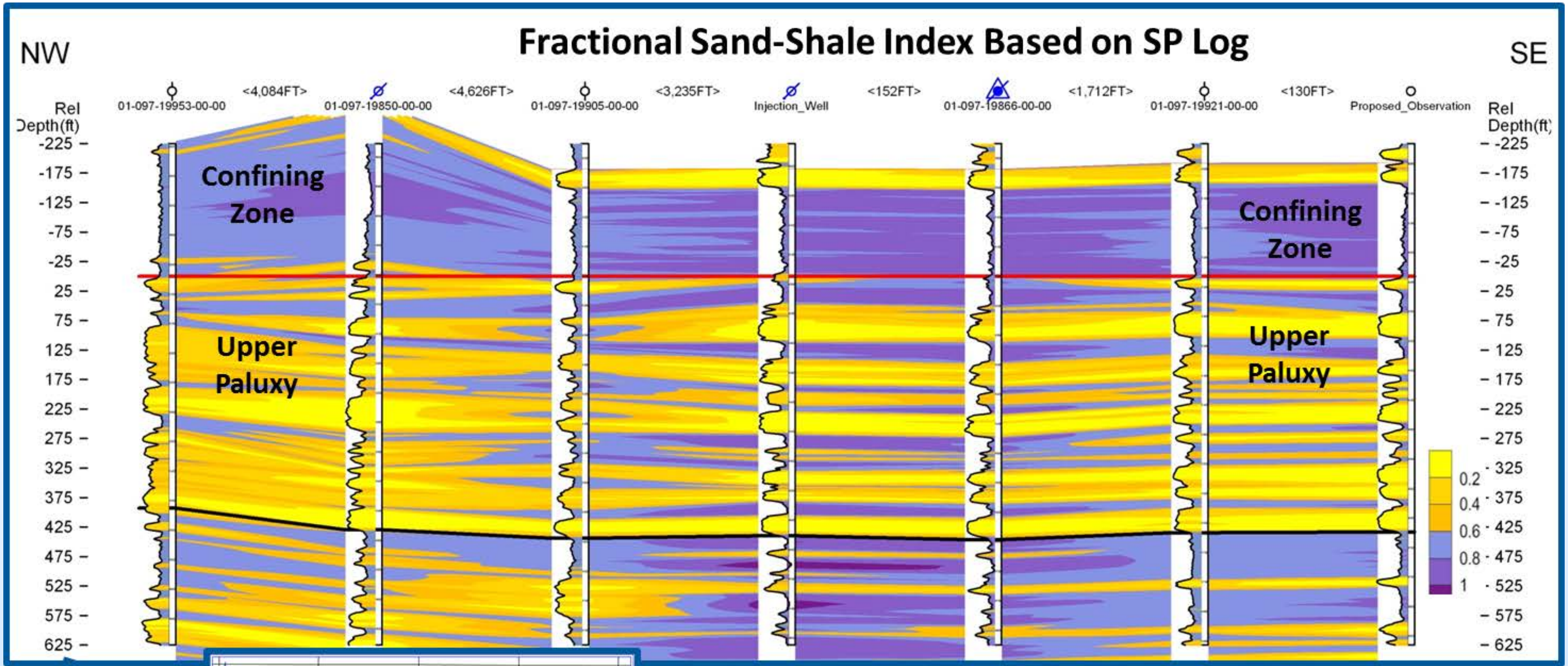


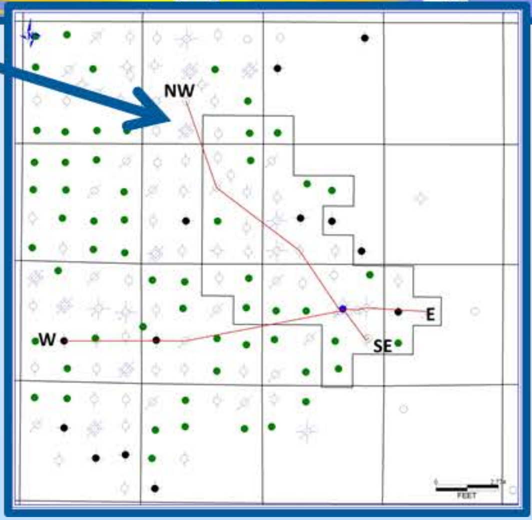
Stratigraphic Column

System	Series	Stratigraphic Unit	Major Sub Units	Potential Reservoirs and Confining Zones
Tertiary	Plio-Pliocene		Citronelle Formation	Freshwater Aquifer
	Miocene	Undifferentiated		Freshwater Aquifer
	Oligocene		Chicasawhay Fm.	Base of USDW
		Vicksburg Group	Bucatunna Clay	Local Confining Unit
	Eocene	Jackson Group		Minor Saline Reservoir
		Claiborne Group	Talahatta Fm.	Saline Reservoir
		Wilcox Group	Hatchetigbee Sand	Saline Reservoir
	Paleocene		Bashi Marl	
			Salt Mountain LS	
		Midway Group	Porters Creek Clay	Confining Unit
Cretaceous	Upper	Selma Group		Confining Unit
		Eutaw Formation		Minor Saline Reservoir
		Tuscaloosa Group	Upper Tusc.	Minor Saline Reservoir
			Mid. Tusc. Marine Shale	Confining Unit
			Lower Tusc. Pilot Sand Massive sand	Saline Reservoir
Cretaceous	Lower	Washita-Fredericksburg	Dantzler sand	Saline Reservoir
			Basal Shale	Primary Confining Unit
		Paluxy Formation	'Upper' 'Middle' 'Lower'	Proposed Injection Zone
		Mooringsport Formation		Confining Unit
		Ferry Lake Anhydrite		Confining Unit
		Donovan Sand	Rodessa Fm. 'Upper'	Oil Reservoir
			'Middle'	Minor Saline Reservoir
			'Lower'	Oil Reservoir

Assessed Zone

Logged Interval



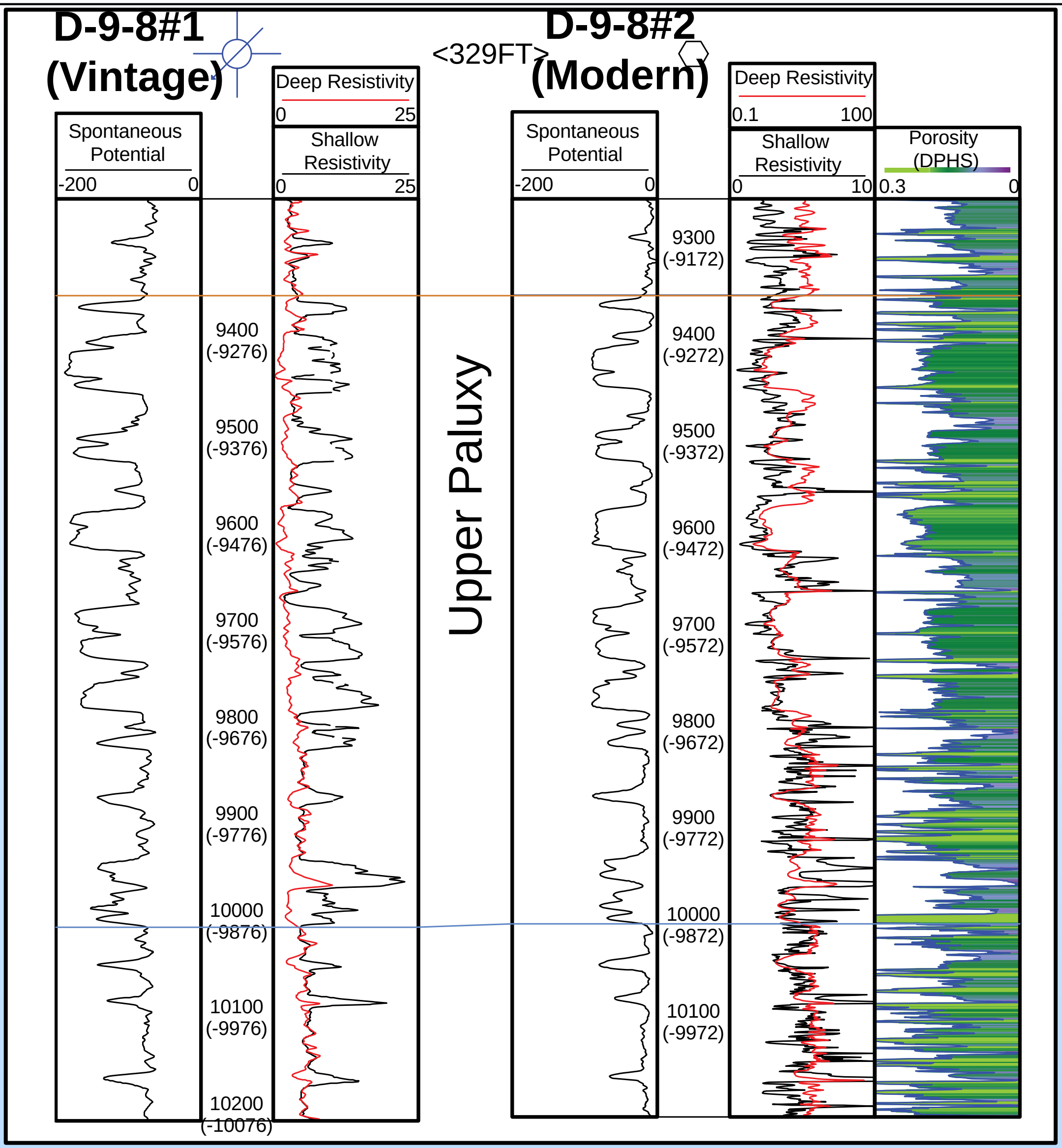


Extrapolated Continuity of Upper Paluxy Sandstones & Confining Units At Citronelle Southeast Unit

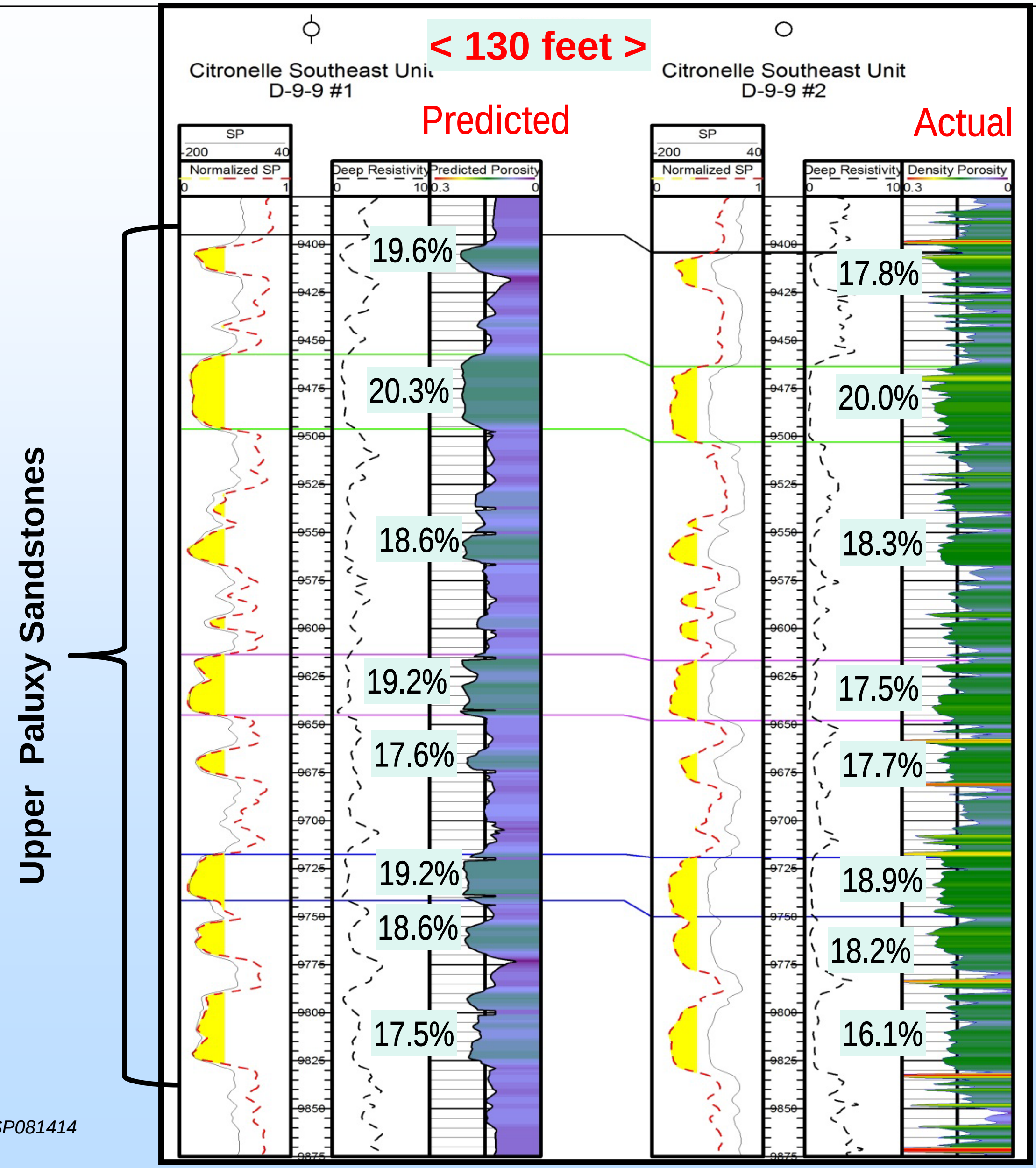
NW – SE Example

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

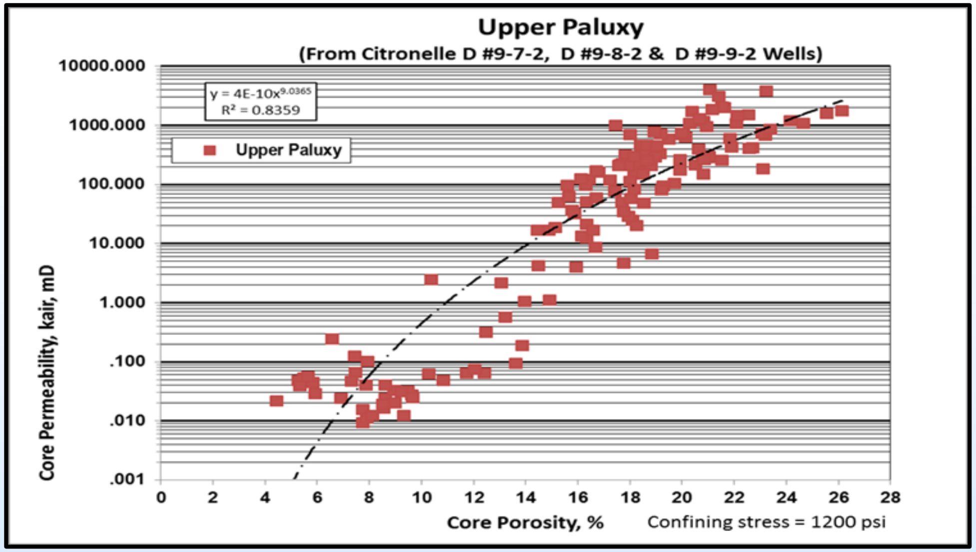


- Porosity predicted from Neural Net for D-9-9 #1 compared to actual density porosity from D-9-9 #2 well.
- Average porosity values for selected Upper Paluxy sandstones are shown.
- Average porosity values for Paluxy sandstones for “predicted” and “actual” are very close.
- Larger range between min and 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_{air} = 373.9 mD (arithmetic)
- Mean k_{air} = 19.3 mD (geometric)

Porosity - Permeability Transform for Upper Paluxy



Examples of Predicted Permeability for Upper Paluxy

Core Porosity, %	Upper Paluxy Core Permeability, mD	Core Porosity, %	Upper Paluxy Core Permeability, mD
6	0.004	**24**	**1,186.7**
8	0.058	**26**	**2,446.1**
12	**2.26**	28	4,778.6
16	**30.4**	30	
20	**228.5**	32	
22	**540.6**	34	

Porosity and Permeability Extrapolated for Each Model Layer

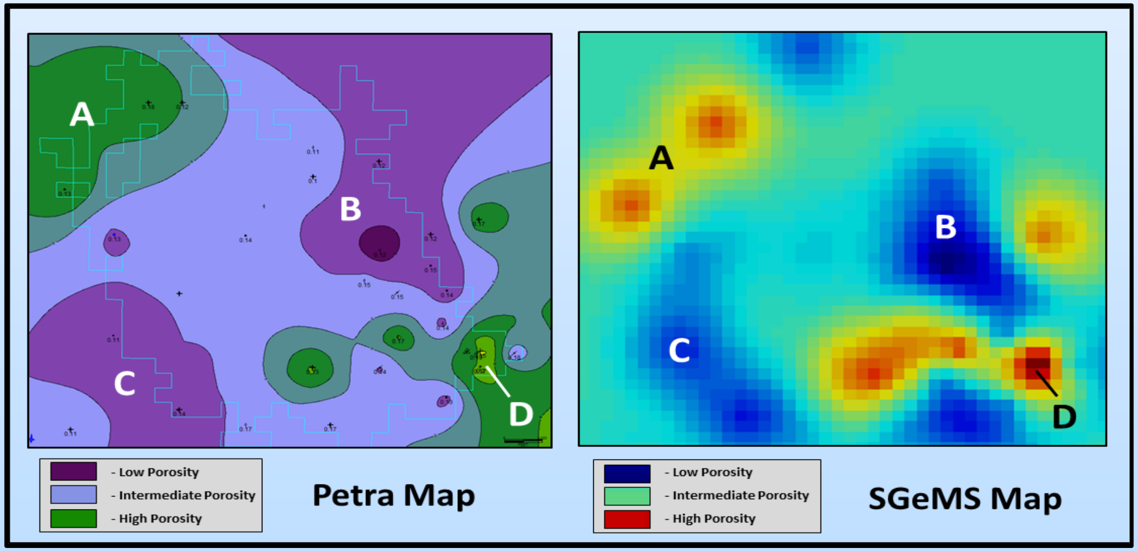
- **Tertiary/ Quaternary** Model Layers (Midway-Surface):
  - Predicted porosity from neural net not successful due poor log data quality/ missing data.
  - A single porosity and permeability value applied for each model layer over the entire study area
- **Cretaceous** Model Layers (Donovan to Selma):
  - Apply geostatistics to interpolate predicted porosity
  - Apply porosity-permeability transforms from core data to extrapolate reservoir permeability from predicted porosity

Formation	# Model Layers
Alluvium	1
Citronelle	1
Miocene	1
Chickasawhay	1
Vicksburg	1
Jackson	1
Claiborne	3
Wilcox	5
Midway	5
Selma	20
Eutaw	20
Upper Tuscaloosa	50
Tuscaloosa Marine Shale	10
Lower Tuscaloosa	30
Washita	60
Fredericksburg	60
KWF Confining	5
Upper Paluxy	60
Lower Paluxy	20
Mooringsport	5
Ferry Lake Anhydrite	1
Donovan	40

Heterogeneity Modeling

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

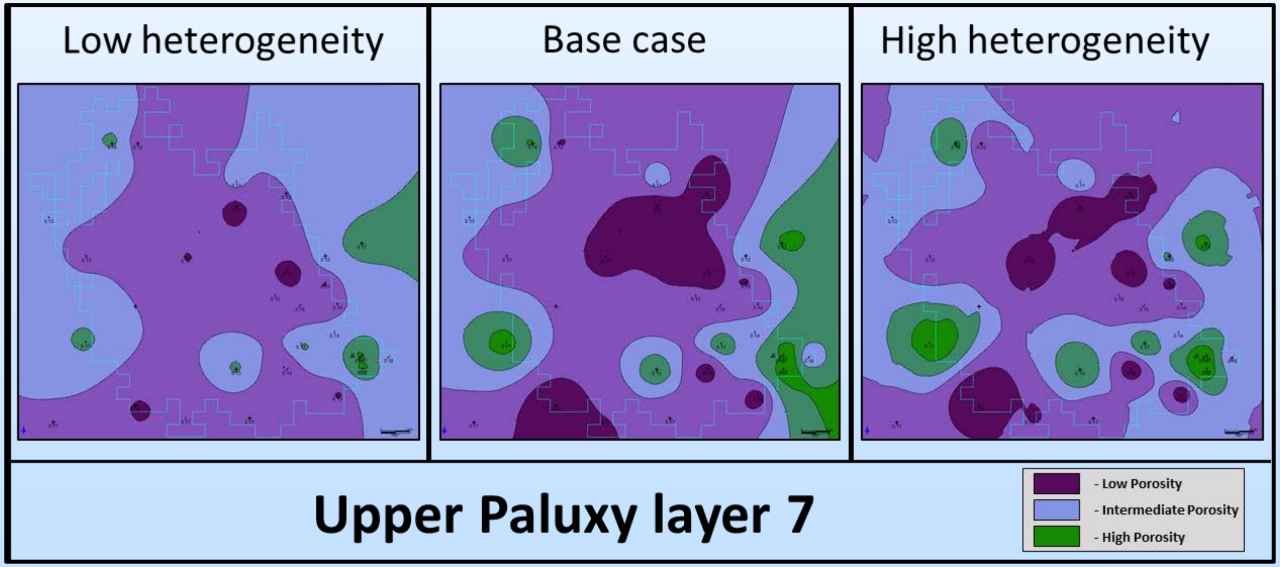
Porosity Interpolation for the Paluxy (Layer 7)



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

Heterogeneity Modeling

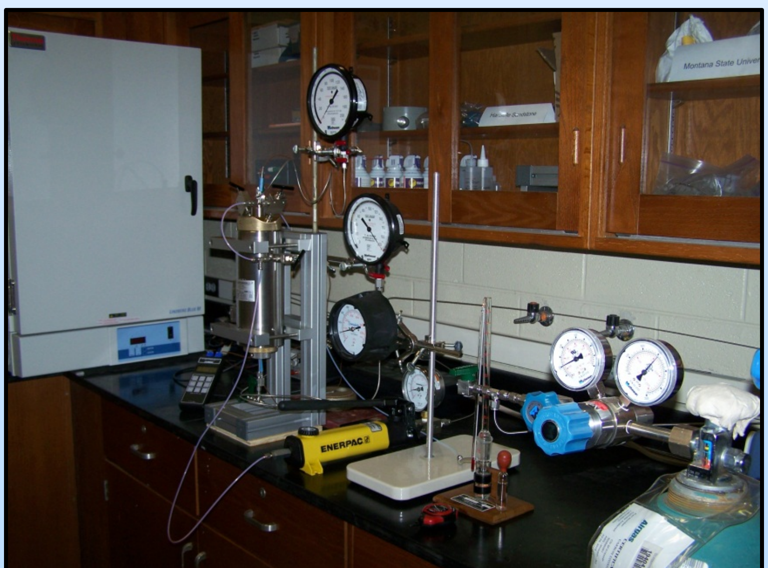
- Moving forward, *Petra* (Kriging) was used to generate the heterogeneity cases for each layer, proving more flexible and efficient.



Heterogeneity Scenario	Surface Style Contouring
Base Case	Highly connected features
Low Heterogeneity	Minimum Curvature
High Heterogeneity	Disconnected Features

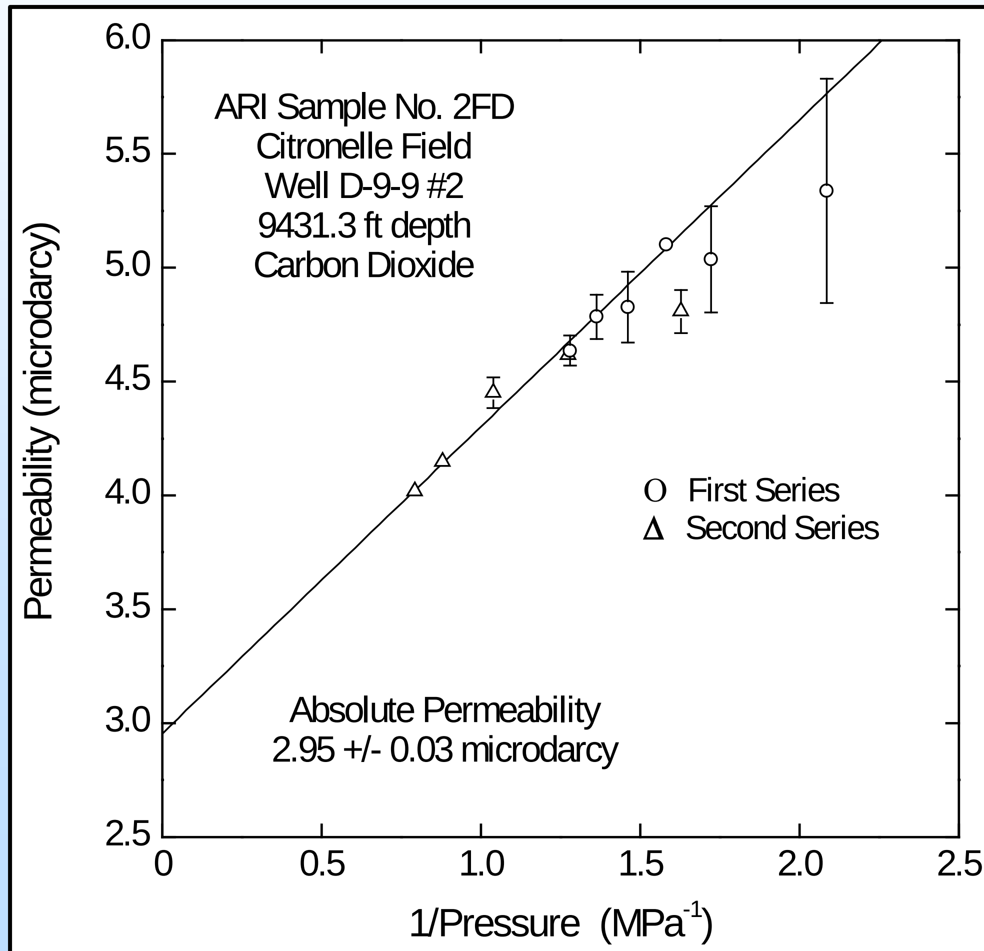
Laboratory Results
Confining Layer in the Paluxy Formation, Citronelle Field

4” dia. core
1” dia. plug



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

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



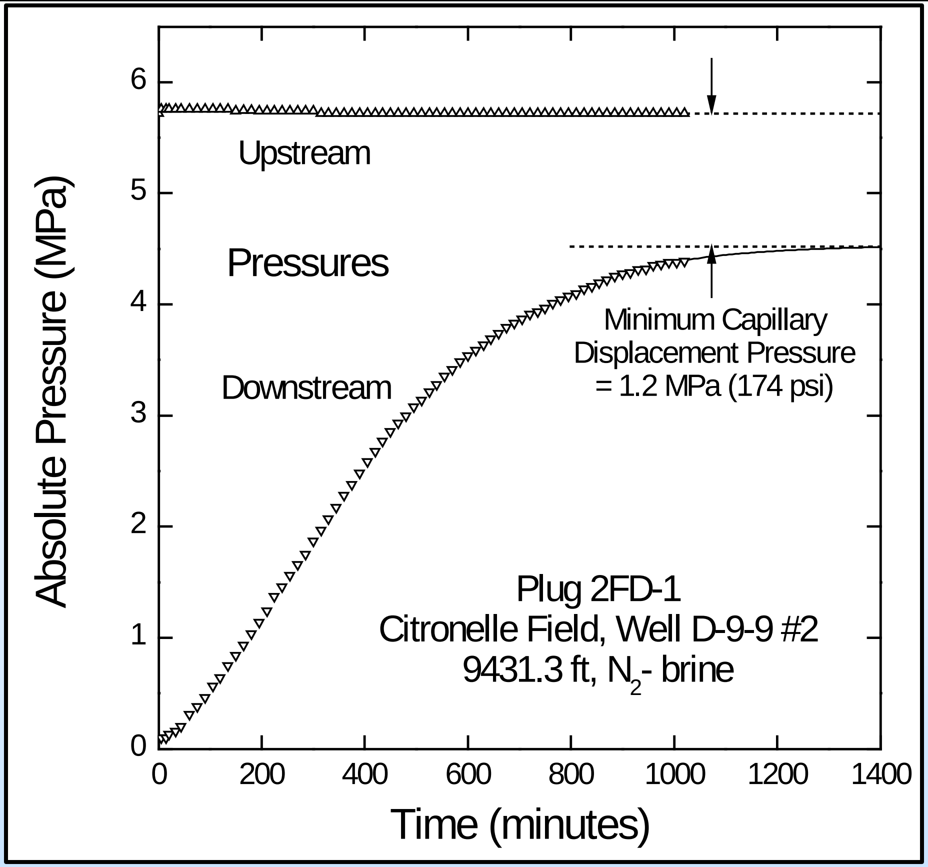
Determination of Minimum Capillary Displacement Pressure*†

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.

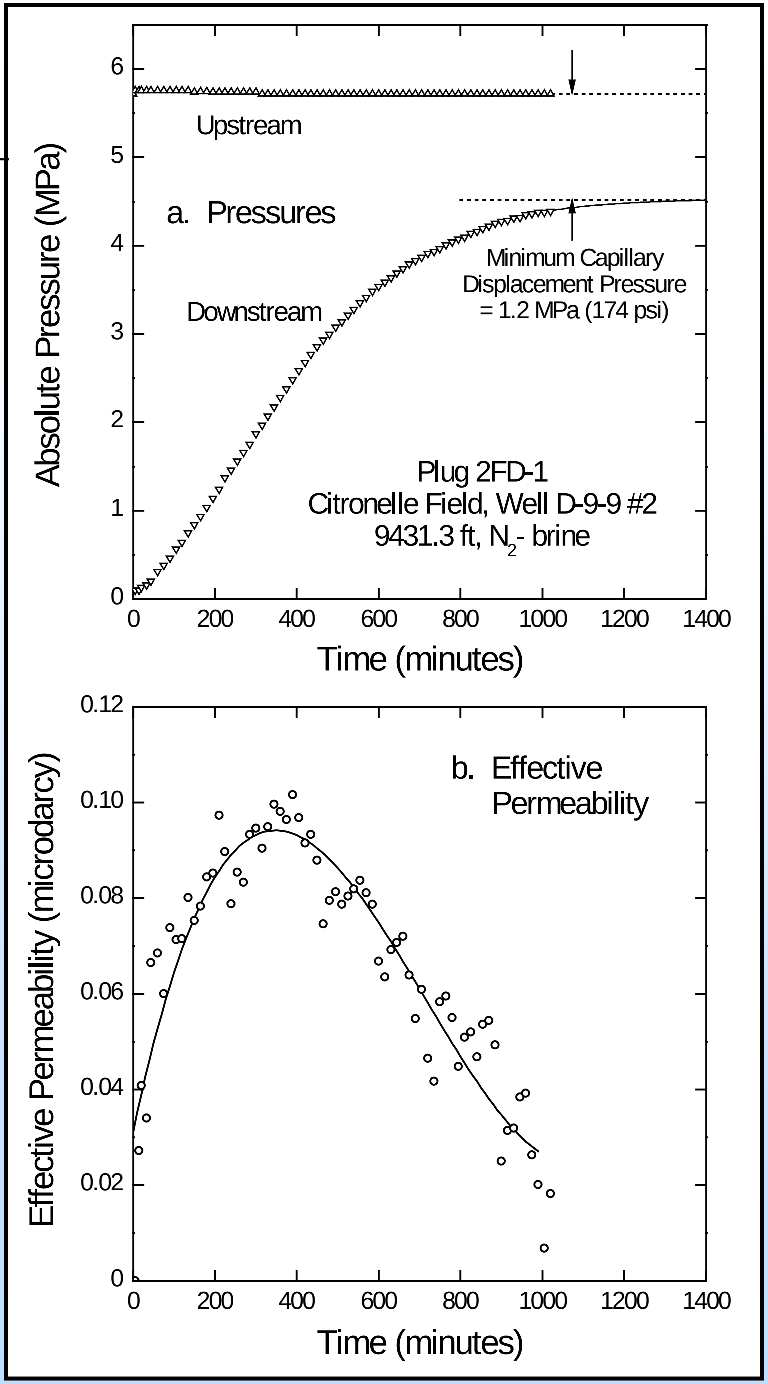
*Hildenbrand, A., S. Schlömer, and B. M. Krooss, "Gas breakthrough experiments on fine-grained sedimentary rocks." *Geofluids*, **2002**, *2*, 3-23.
†Hildenbrand, A., S. Schlömer, B. M. Krooss, and R. Littke, "Gas breakthrough experiments on pelitic rocks: comparative study with N_2, CO_2 and CH_4," *Geofluids*, **2004**, *4*, 61-80.

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.



*Hildenbrand, A., S. Schlömer, and B. M. Krooss, "Gas breakthrough experiments on fine-grained sedimentary rocks." *Geofluids*, **2002**, *2*, 3-23.

†Hildenbrand, A., S. Schlömer, B. M. Krooss, and R. Littke, "Gas breakthrough experiments on pelitic rocks: comparative study with N_2, CO_2 and CH_4," *Geofluids*, **2004**, *4*, 61-80.

Effective Permeability vs. Pressure

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

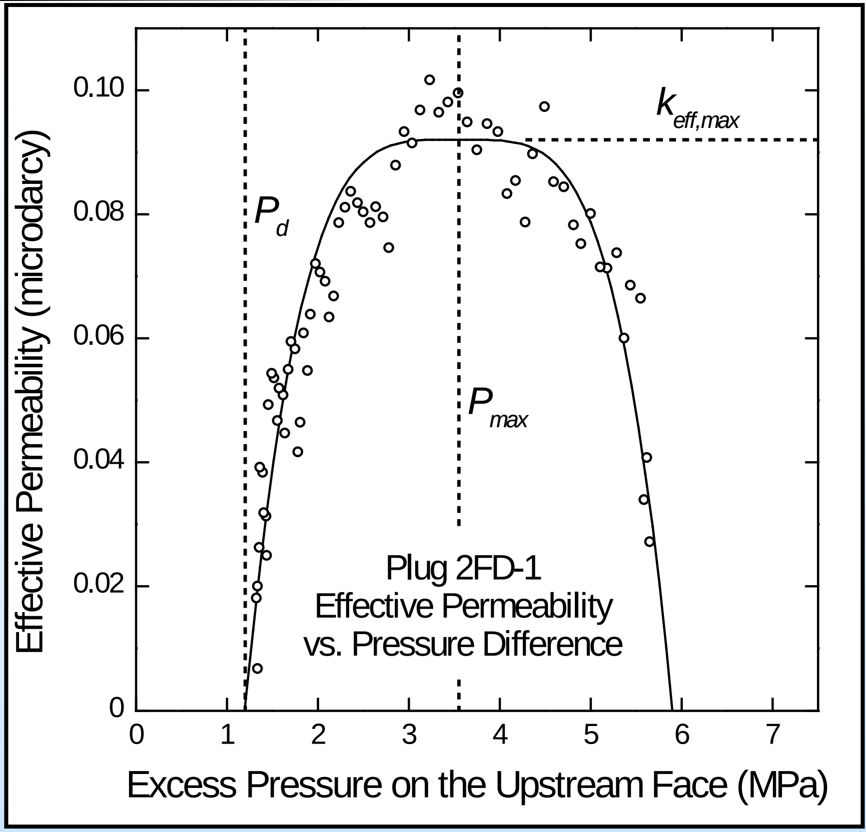
The minimum capillary displacement pressure, P_d (1.2 MPa, 174 psi) is the pressure at breakthrough, on the left.

The effective permeability varies from 0 at the minimum capillary displacement pressure to a maximum of 0.09 to 0.10 microdarcy at P_{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:

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

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

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

Relationship between pore radius and capillary pressure:

$$P_{capillary} = \frac{2\,\gamma\cos\vartheta}{r} \qquad (2)$$

Washburn (1921).

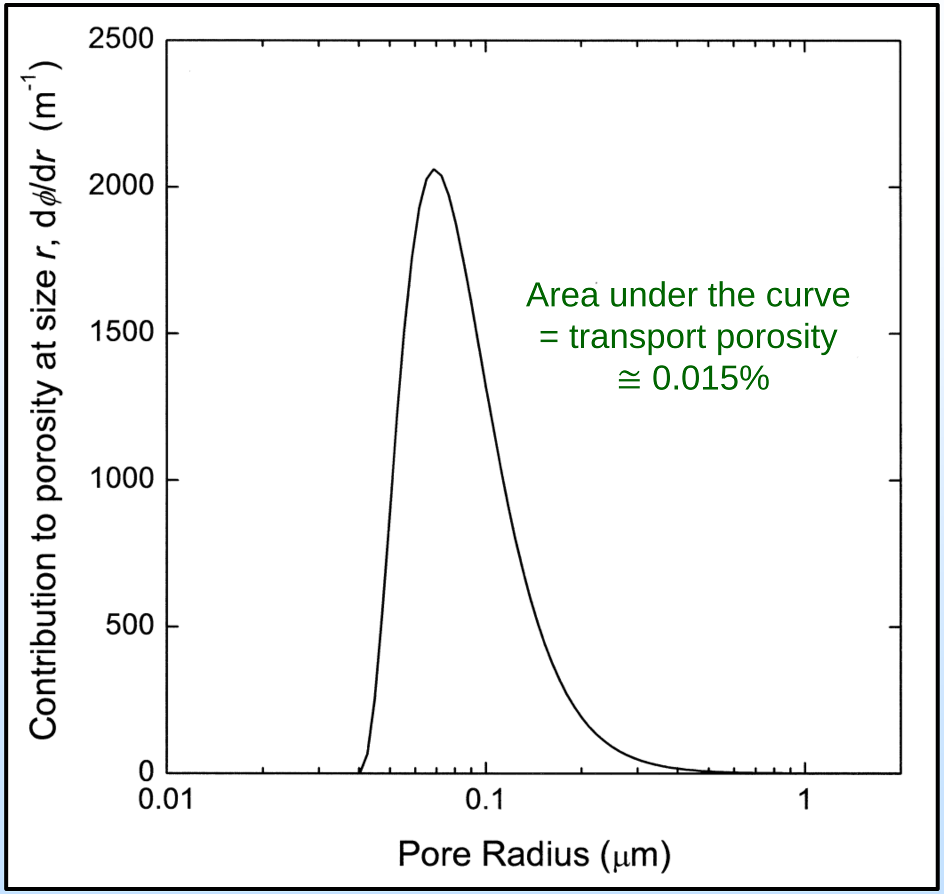
Rate of change of porosity, ϕ, with increase

In radius, *r*, of *N* parallel monosize pores:

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

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.

Leakage through a Confining Layer

Injected CO_2 is treated as a simple column having uniform cross section and depth.

Rate of CO_2 storage (mass per unit time per unit plan area) = injection rate – leakage rate.

Excess pressure at the confining layer/reservoir interface = (density brine - density CO_2)
x g x height of CO_2 column

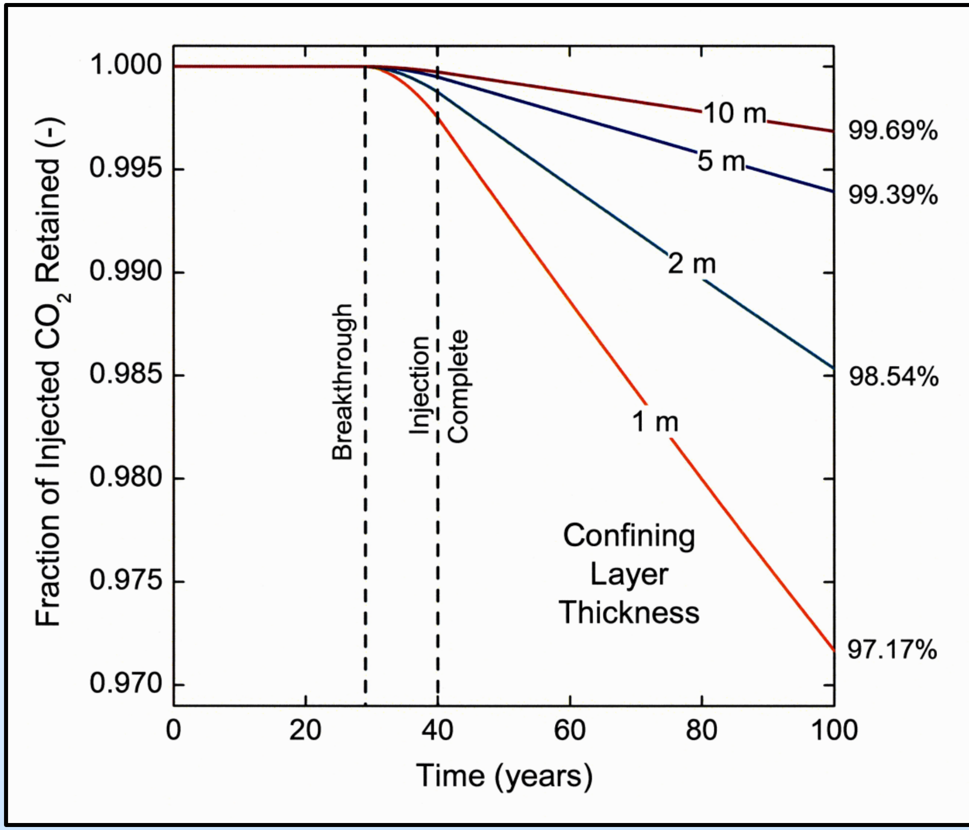
Leakage begins when the excess pressure exceeds the minimum capillary displacement pressure.

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

CO_2 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 CO_2 injection.

For confining layers thicker than about 5 m, >99% of CO_2 is retained at 100 years.



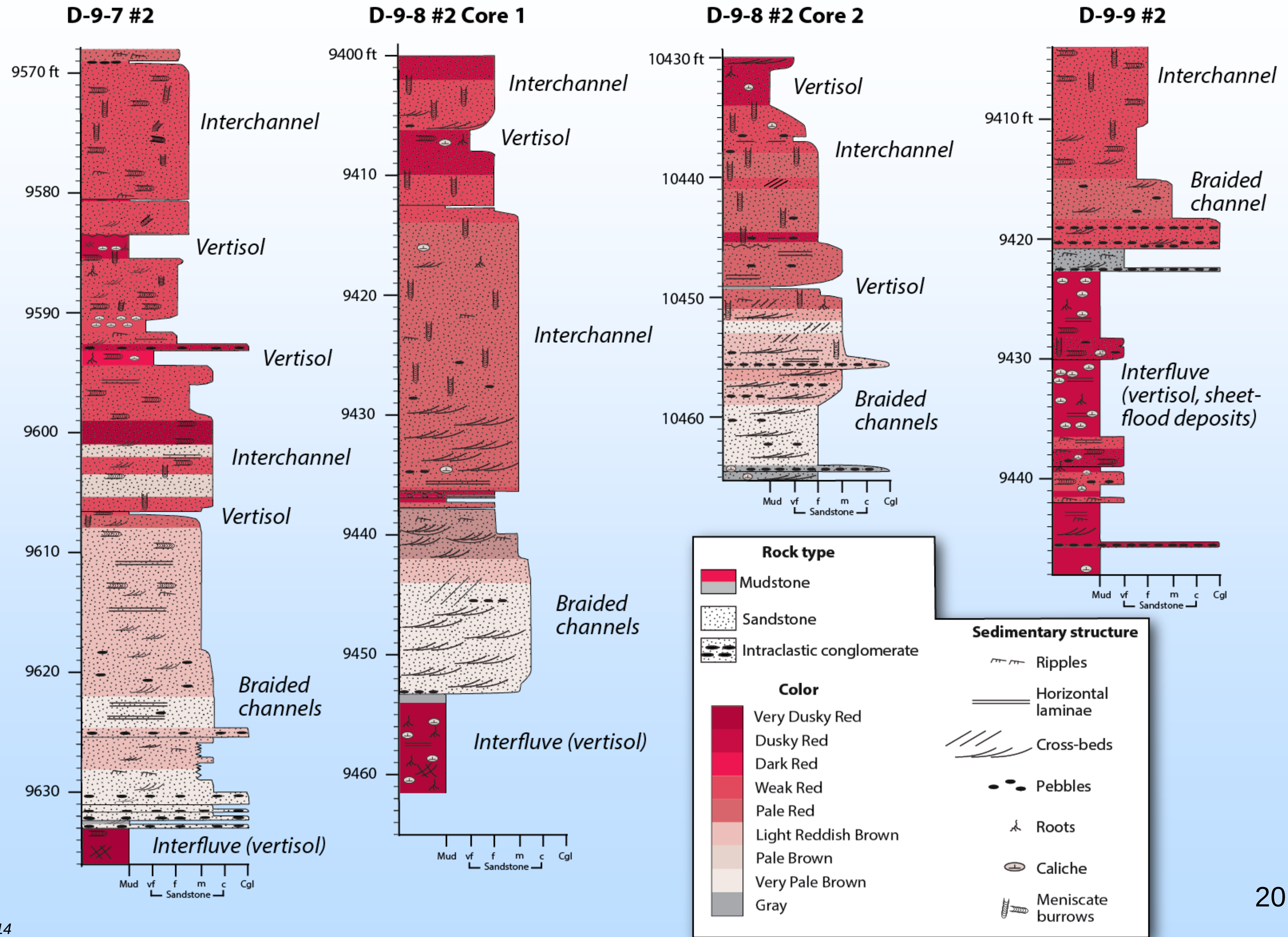
Porosity of the storage reservoir: 19%

Minimum capillary displacement pressure: 174 psi

CO_2 column height at breakthrough: 273 m

Maximum permeability of the confining layer: $k_{eff,max}$ = 0.095 microdarcy at 515 psi

Graphic Core Logs



Reservoir Sandstone

Cross-beds

Ripple cross-laminae

Core width = 10 cm

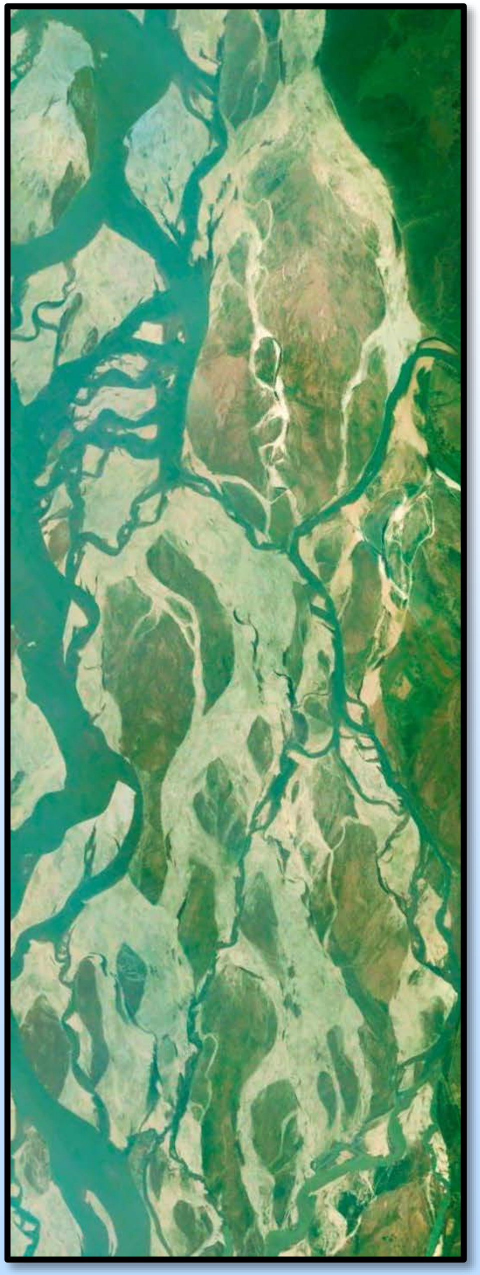
Meniscate burrows

(insects and other soil dwellers)

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

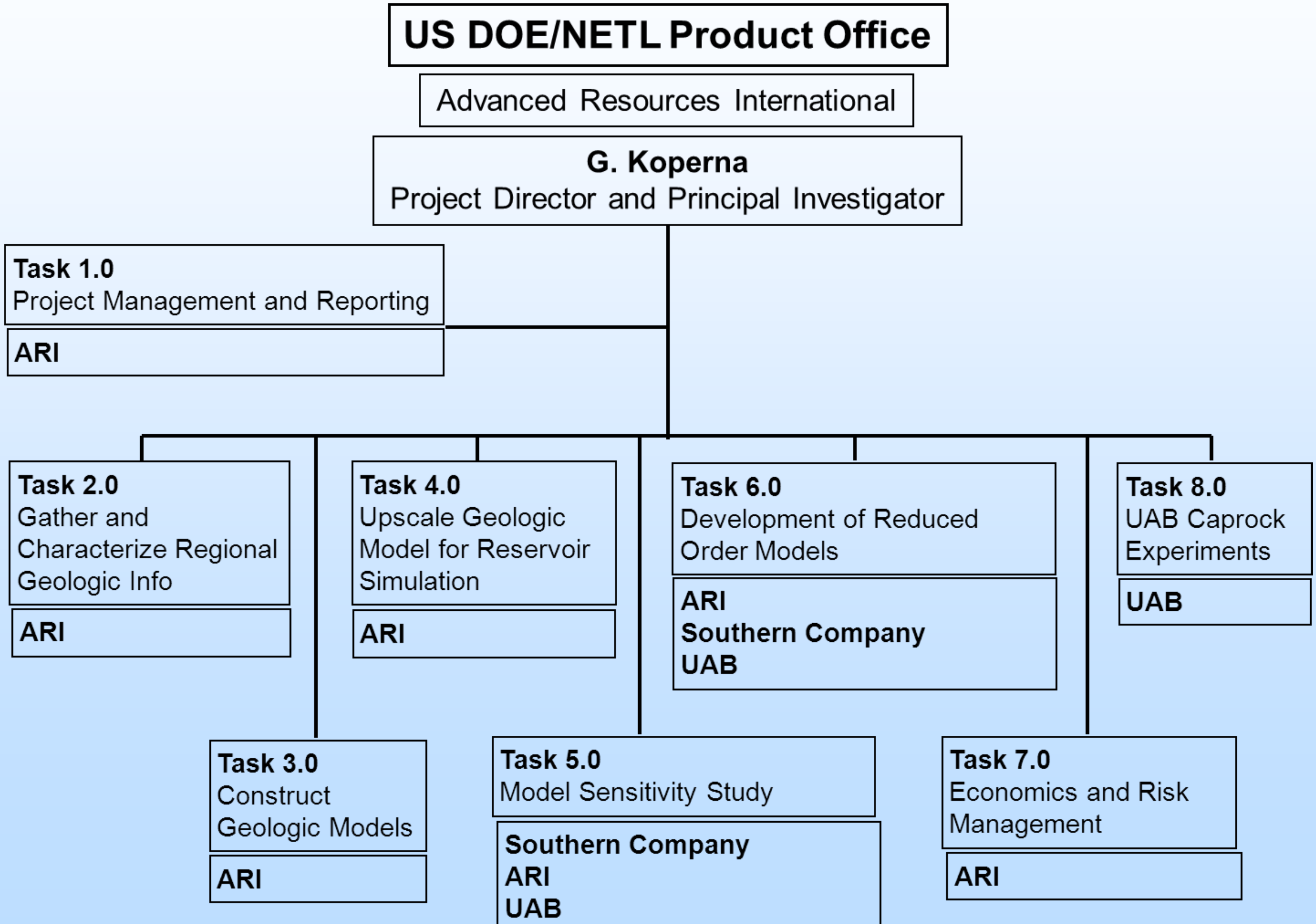
Key Findings/ Lessons Learned

- The Project Team is able to successfully characterize a subsurface volume of 1.9E+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 permeablities through brine-filled confining units appear to be on the order of 1/30th 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

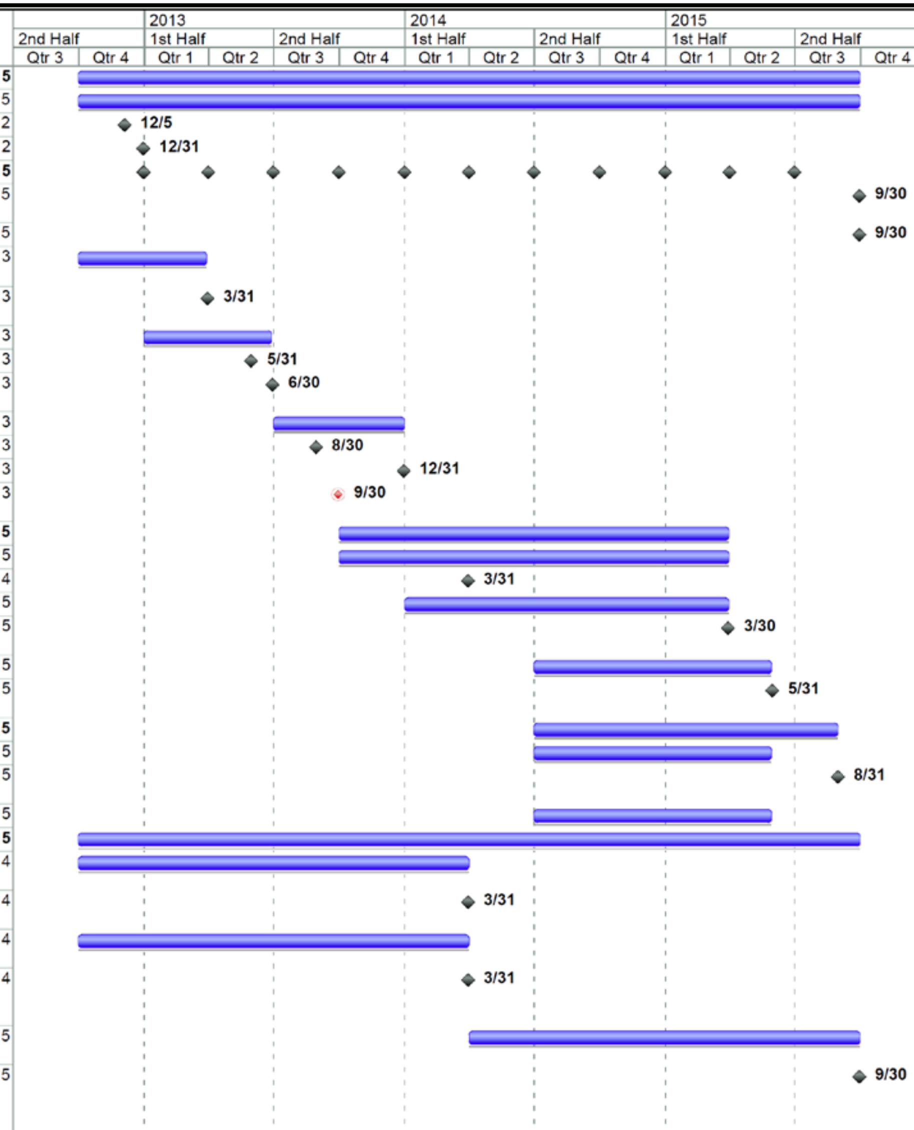
- **Sensitivity Study**: Will explore sensitivities such as well design and lateral heterogeneity to maximize storage capacity while minimizing the operation's footprint.
- **Optimization**: Will incorporate economic and risk management considerations which will be overlain on the modeling results to 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.
- **Best Practices Manual**: Will produce a Best Practices Manual for optimized commercial-scale storage.

Appendix: Organization Chart



Appendix: Gantt Chart

Task Name		Start	Finish
Task 1: Project Management	150,017	**Mon 10/1/12**	**Wed 9/30/15**
Subtask 1.1 – Project Management Plan		Mon 10/1/12	Wed 9/30/15
Deliverable 1.1 – Report, Project management plan		Wed 12/5/12	Wed 12/5/12
Deliverable 1.2 – Project Management and Reporting		Mon 12/31/12	Mon 12/31/12
Deliverable 1.3 – Report, Quarterly progress reports		**Mon 12/31/12**	**Wed 7/1/15**
Deliverable 1.4 – Best Practices Manual for CO2 storage in the U.S. Eastern Gulf Coast		Wed 9/30/15	Wed 9/30/15
Deliverable 1.5 – Final project reports		Wed 9/30/15	Wed 9/30/15
Task 2: Gather and Characterize Regional Geologic Information	66,670	Mon 10/1/12	Fri 3/29/13
Deliverable 2.1 – Report, Using neural network algorithms to modernize vintage well logs		Sun 3/31/13	Sun 3/31/13
Task 3: Construct Geologic Models	51,543	Tue 1/1/13	Fri 6/28/13
Deliverable 3.1 – Meeting, Geologic data review and critique		Fri 5/31/13	Fri 5/31/13
Deliverable 3.2 – Report, Geostatistical analysis of southeastern sediments		Sun 6/30/13	Sun 6/30/13
Task 4: Upscale Geologic Model for Reservoir Simulation	46,326	Mon 7/1/13	Tue 12/31/13
Deliverable 4.1 – Meeting, Modeling data review and critique		Fri 8/30/13	Fri 8/30/13
Deliverable 4.2 – Report, Upscaling comparison to geologic data		Tue 12/31/13	Tue 12/31/13
Decision Point – Demonstration of capability to effectively model geology and subsurface CO2 flow		Mon 9/30/13	Mon 9/30/13
Task 5: Model Sensitivity Study	53,180	**Tue 10/1/13**	**Mon 3/30/15**
Subtask 5.1 – Injection Scenario Simulations		Tue 10/1/13	Mon 3/30/15
Deliverable 5.1 – Meeting, Modeling data review and critique		Mon 3/31/14	Mon 3/31/14
Subtask 5.2 – Visualization of Simulation Results		Wed 1/1/14	Mon 3/30/15
Deliverable 5.2 – Report, Modeling results and storage efficiency factors		Mon 3/30/15	Mon 3/30/15
Task 6: Development of Scoping/Screening Level Models	45,017	Tue 7/1/14	Fri 5/29/15
Deliverable 6.1 – Report, Reduced order model and code module		Sun 5/31/15	Sun 5/31/15
Task: 7: Economics and Risk Management	53,227	**Tue 7/1/14**	**Mon 8/31/15**
Subtask 7.1 – Economic Assessment		Tue 7/1/14	Fri 5/29/15
Deliverable 7.1 – Report, Economic and risk management modeling results		Mon 8/31/15	Mon 8/31/15
Subtask 7.2 – Risk Assessment		Tue 7/1/14	Fri 5/29/15
Task 8: UAB Task - Ensuring Containment	332,877	**Mon 10/1/12**	**Wed 9/30/15**
Subtask 8.1 Measurement of Minimum Capillary Displacement Pressures		Mon 10/1/12	Mon 3/31/14
Deliverable 8.1 – Measurements of permeability and capillary displacement pressure of cap rock samples		Mon 3/31/14	Mon 3/31/14
Subtask 8.2 Simulation and Visualization of CO2 Seepage in the absence of Chemical Reactions		Mon 10/1/12	Mon 3/31/14
Deliverable 8.2 - Dynamic visualization of CO2 seepage based on simulations of CO2 behavior in cap rocks, in the absence of chemical reactions		Mon 3/31/14	Mon 3/31/14
Subtask 8.3 Evolution of Cap Rock Properties in the Presence of Carbon Dioxide		Tue 4/1/14	Wed 9/30/15
Deliverable 8.3 - Measurements and modeling of changes in cap rock properties and CO2 injection, migration, and trapping in the presence of chemical reactions, including cumulative CO2 loss		Wed 9/30/15	Wed 9/30/15



Appendix: Bibliography

- *Geologic Characterization for the U.S. SECARB Anthropogenic Test; Combining Modern and Vintage Well Data to Predict Reservoir Properties,* Shawna R. Cyphers, Hunter Jonsson, and George J. Koperna, Jr., poster presentation, American Association of Petroleum Geologists, Annual Convention & Exhibition, Pittsburgh, PA, May 19-22, 2013.

- *Constructing a Geologic Model to Simulate Commercial Scale CO_2 Injection and Optimization of Storage Capacity in the Southeastern United States*, Hunter Jonsson, Shawna Cyphers, George Koperna, Robin Petrusak, presentation abstract accepted for Carbon Management Technology Conference, CMTC 2013, Alexandria, Virginia, October 21 – 23, 2013

- *Constructing a Geologic Model to Simulate and Optimize the Commercial Scale Injection and Storage of CO_2 at Citronelle Field, Mobile County, Alabama*, J. MacGregor, R. Petrusak, S.R. Cyphers, H. Jonsson, A. Oudinot, and G.J. Koperna, poster presentation, 2014 AAPG Annual Convention & Exhibition, Houston, Texas, April 6- 9 2014.