Commercial Scale CO_2 Injection and Optimization of Storage Capacity in the Southeastern United States

Project Number: DE-FE0010554

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U.S. Department of Energy
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Carbon Storage R&D Project Review Meeting
Developing the Technologies and Infrastructure for CCS
August 18-20, 2015

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

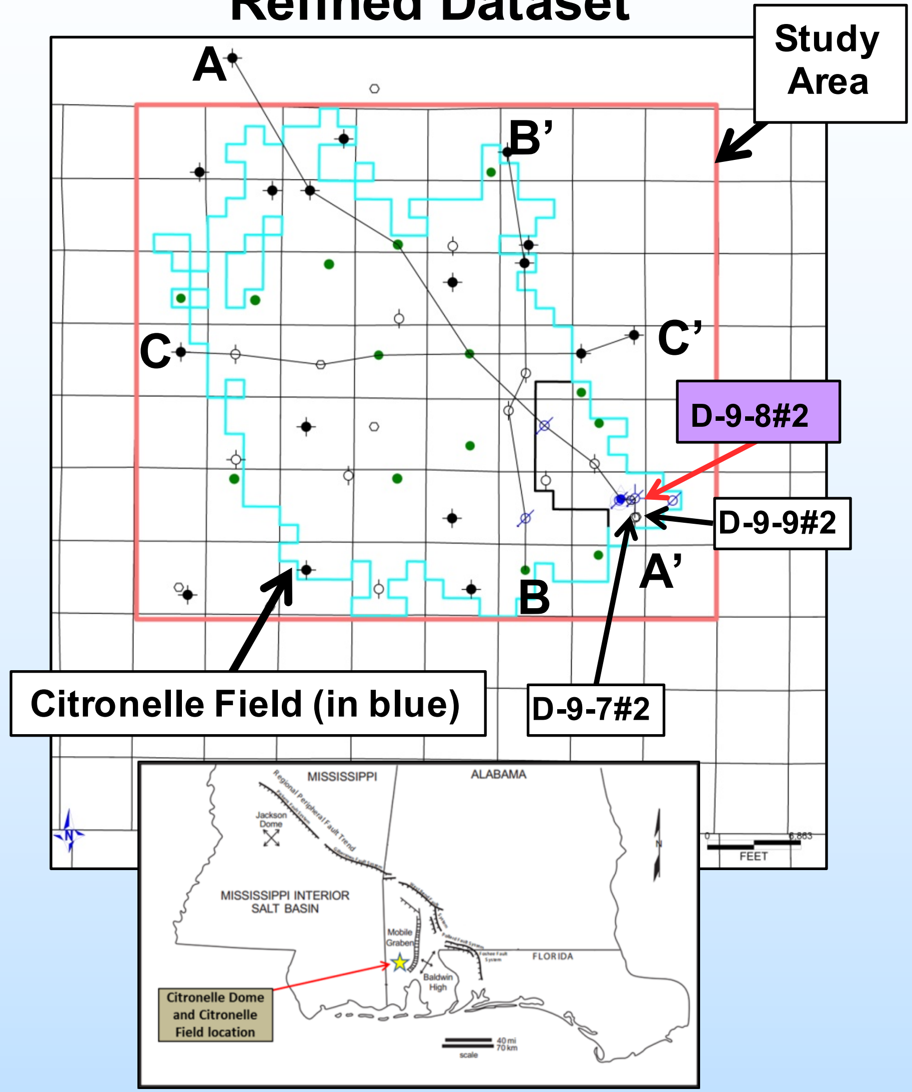
Project Objectives

- 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

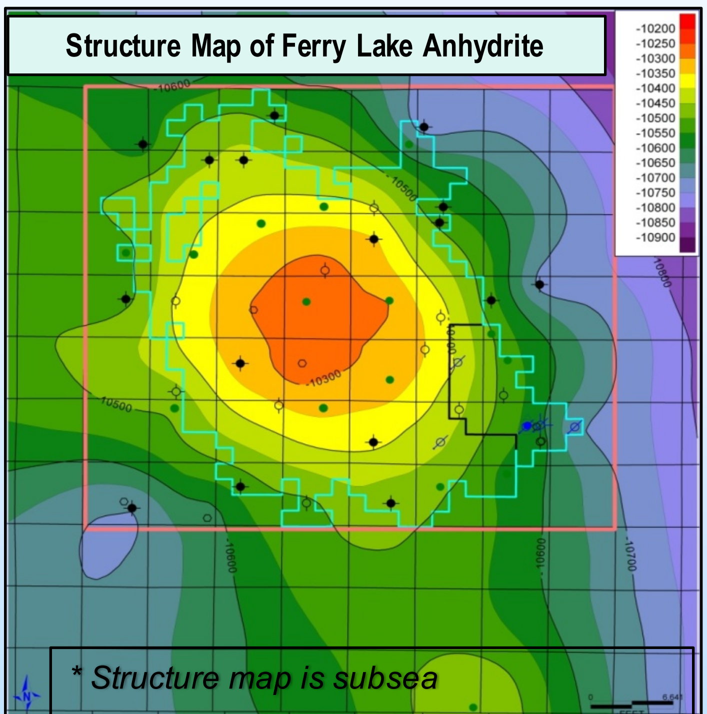
- The Citronelle Field is a 56 sq. mile study area with 400+ wells on 40-ac spacing
- Geologic model characterizes injection zones and confining units from surface though the Donovan sandstones at depths >12,000 ft.
- D 9-8 #2 well in Citronelle Southeast Unit selected as Type Log for geologic correlations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

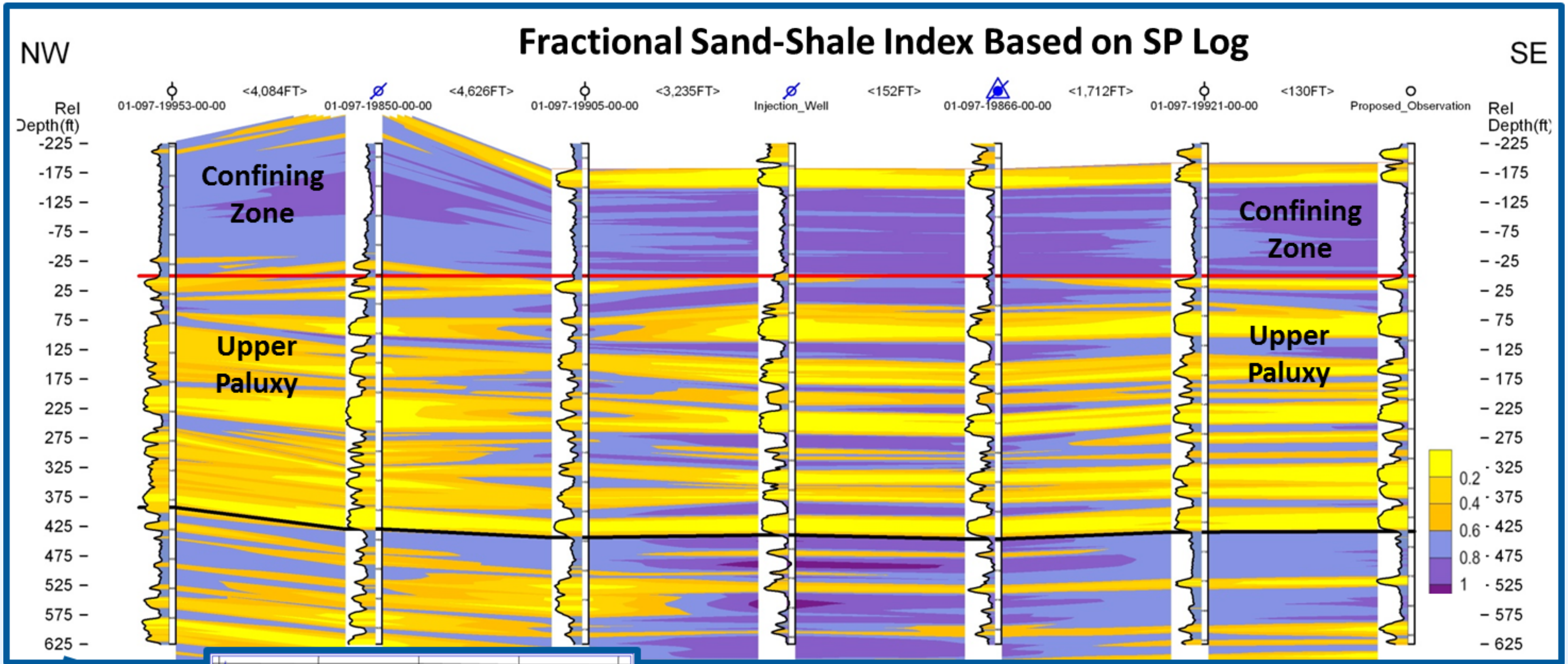


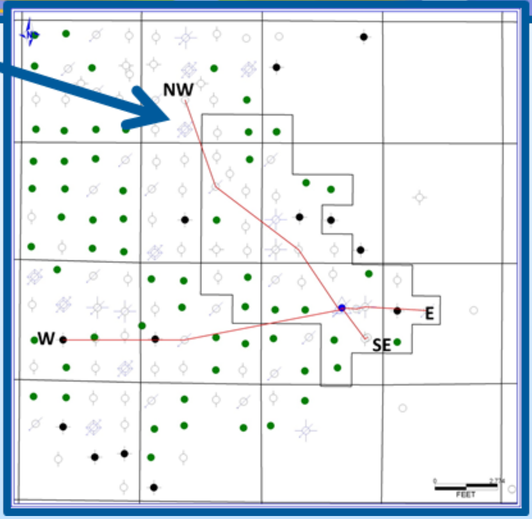
Stratigraphic Column

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

Assessed Zone

Logged Interval





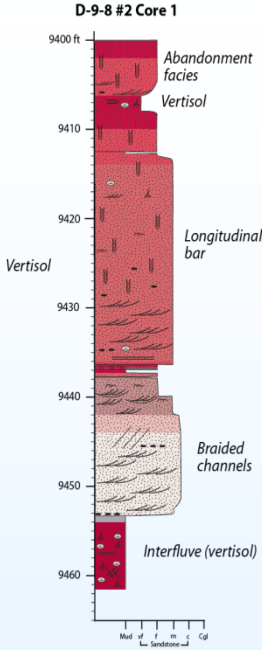
Extrapolated Continuity of Upper Paluxy Sandstones & Confining Units at Citronelle Southeast Unit NW – SE Example

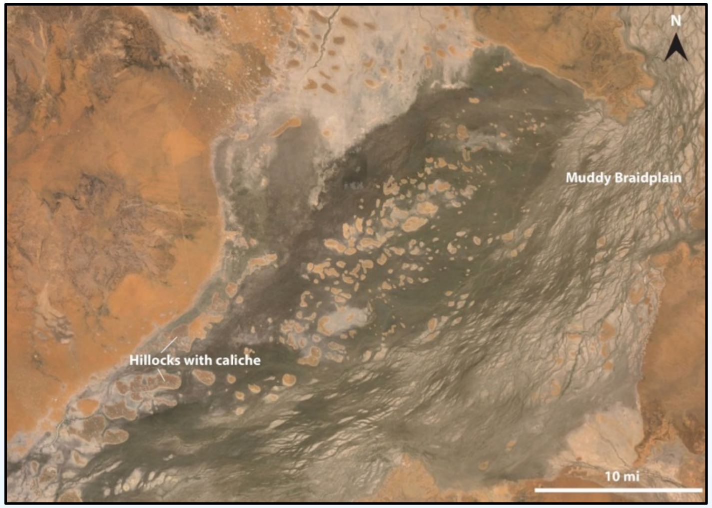
Cross Sections of the study area highlight:

- Continuity of cap rock and reservoirs
- However, high resolution analysis depicts relatively fine-scale heterogeneity of reservoirs

OSU Depositional Systems Analysis

Sandstone resembles classic sandy braided stream deposits, South Saskatchewan River





Holocene muddy braidplains with calcrete in Cooper's Creek, Lake Eyre Basin, eastern Australia; maximum width ~10 miles

- Depositional environment yielded multistorey, bedload-dominated fluvial deposits interbedded with interfluvial mudstone in braidplain setting.
- Reservoir porosity commonly >20% and permeability up to 3.8 Darcies making the Paluxy Fm. an ideal CO_2 injection zone.
- Wash-Fred seal laterally extensive but in complex facies relationship with reservoir quality sandstone.
- *Similar deposits are widespread in Lower Cretaceous of Gulf of Mexico region*
- Delineating reservoir heterogeneity helps in identifying and prioritizing CO_2 injection zones, understanding reservoir confinement, and subsurface flow pathways.

Reservoir Sandstone

Cross-beds

Ripple cross-laminae

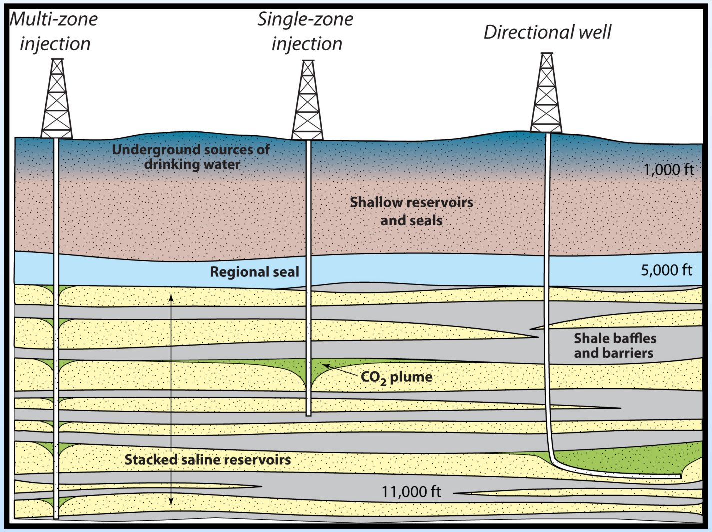
Meniscate burrows

(insects and other soil dwellers)

Core width = 10 cm

OSU Depositional Analysis

- Sandstone continuity, reservoir quality greatest in basal and upper Paluxy.
- Available reservoir thickness greatest in upper Paluxy.
- Individual sandstone bodies not mapable across field; critical injection planning best conducted in specific plume areas.
- Wash-Fred seal widespread; locally in facies relationship with reservoir-quality sandstone.
- Wash-Fred sandstone provides buffer; storage security bolstered by numerous additional seals
- Multiple options available; multizone storage minimizes footprint, distributes pressure buildup.



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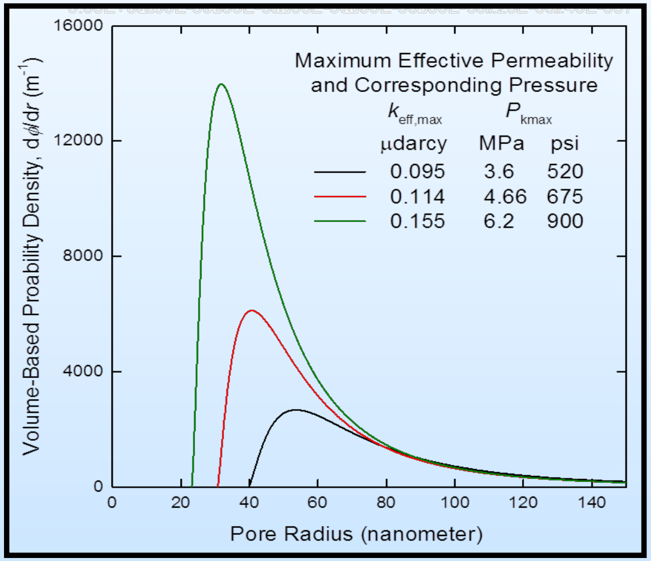
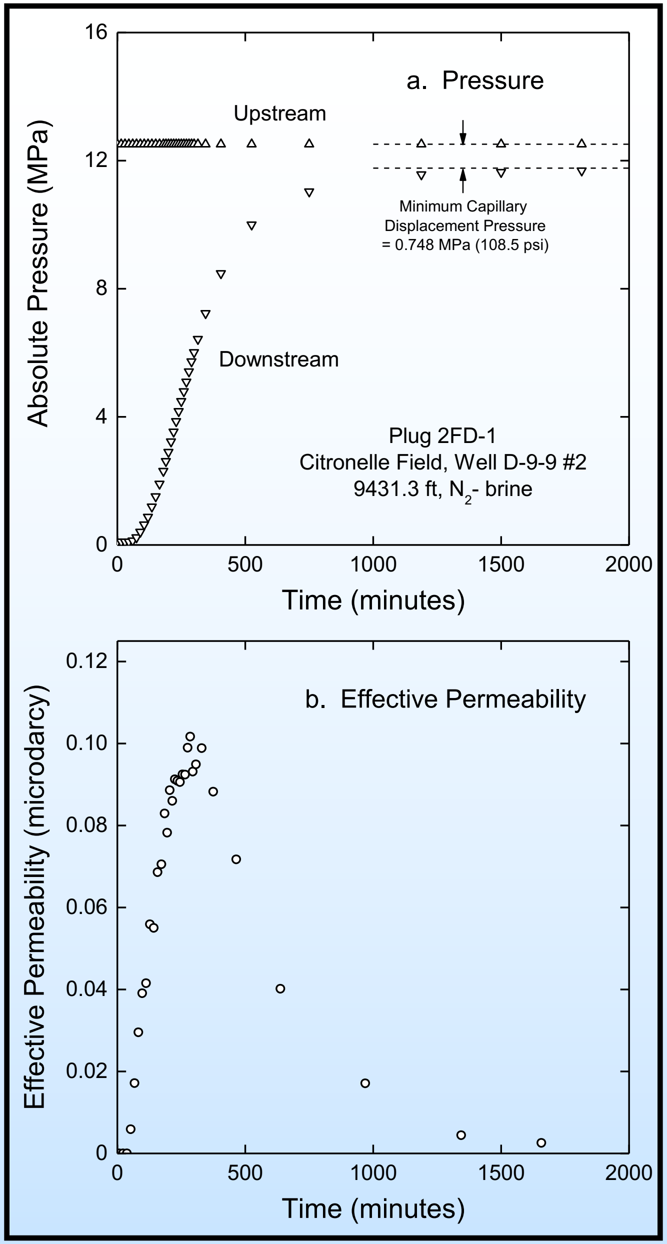
UAB Core Analyses

- The minimum capillary displacement pressure was measured to be 0.748 Mpa (108.5 psi)
  - *This represents the minimum pressure at which gas would break through brine-saturated rock given enough time.*
- The maximum effective permeability was measured to be 0.09 to 0.10 microdarcy
  - *This determines the max flow rate through a confining layer following breakthrough.*



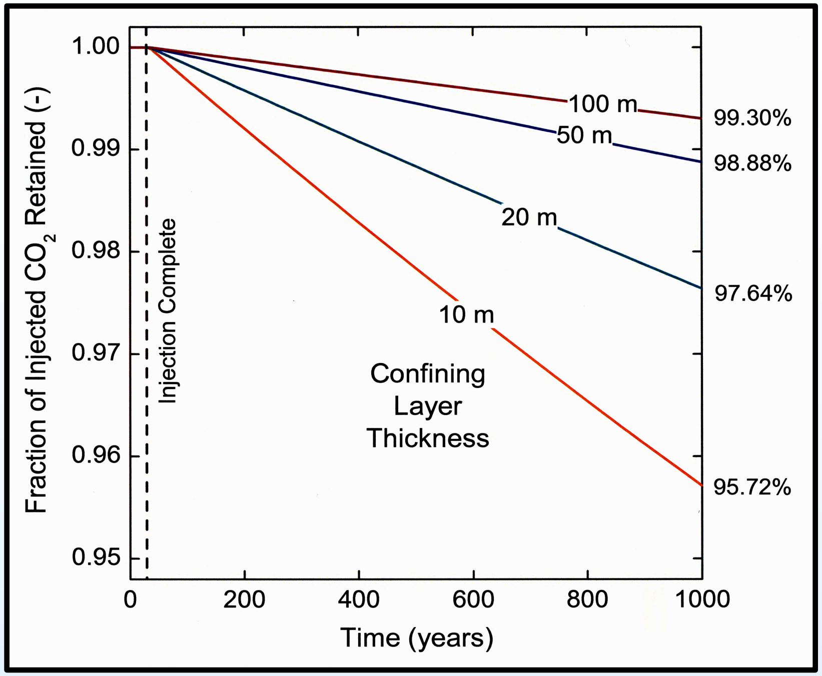


- Size distribution of the conducting pores was measured for three different initial pressures

UAB Core Analyses

Leakage through a Confining Layer was measured on core and modeled for four separate thicknesses, from 10 to 100 meters.

- Breakthrough occurs 29 years after the start of CO_2 injection, but is undetected, so injection continues to the planned 40 years.
- For confining layers thicker than about 100 m, >99% of CO_2 is retained at 1000 years.

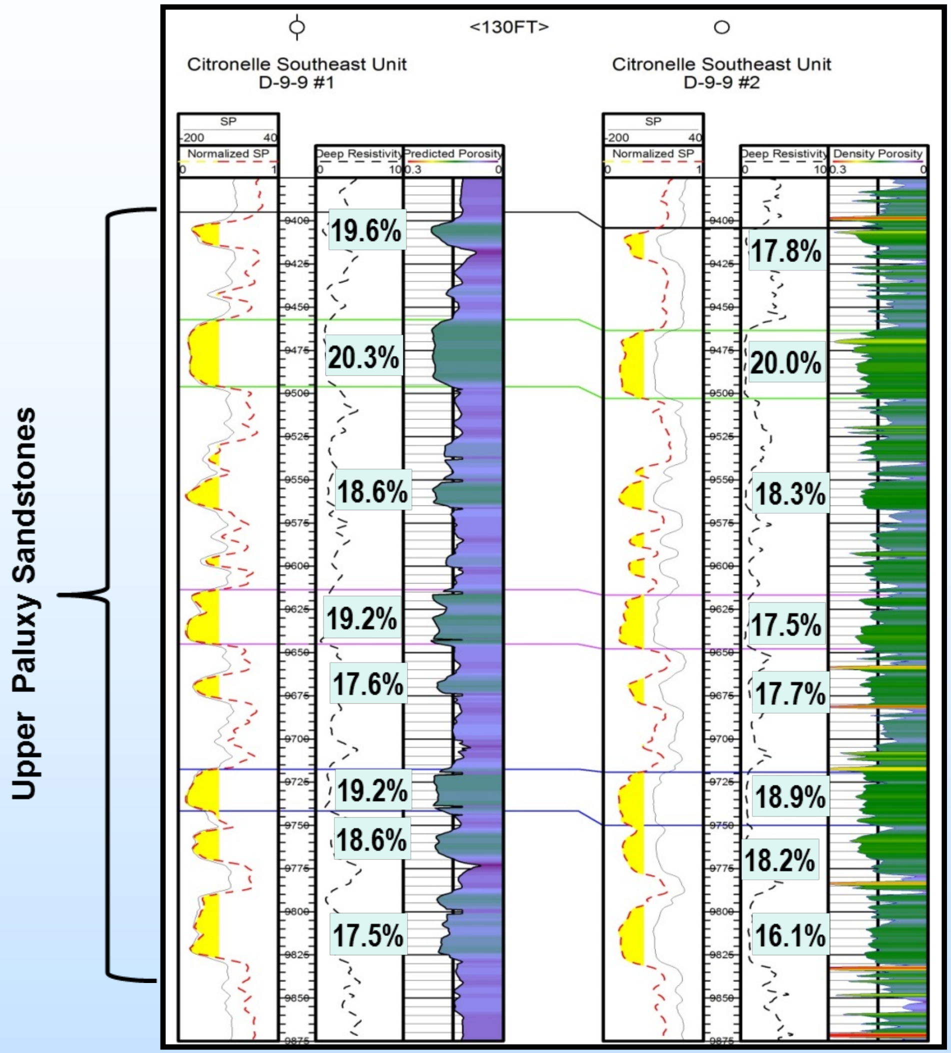


Conditions

- CO_2 is injected at a rate of 500 metric tons/day for 40 years into wells on 40-acre centers.
- 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

Porosity Prediction

- Most legacy wells only have resistivity logs and no porosity logs.
- 3 new wells with modern porosity logs were drilled on well pads with existing abandoned wells.
- These paired wells provided a unique opportunity to apply a neural network approach to predict porosity for 36 wells.
    - Predictions were applied to all logged intervals – commonly from the Donovan up through the Midway
- 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 the Paluxy sandstones highlight how closely the values predicted by the neural network correlate to the logged values (density porosity).
    - Larger range between min and max values and finer vertical resolution for actual porosity than for "predicted" porosity.



Predicted Values Logged Values

Porosity and Permeability Extrapolated for Each Model Layer

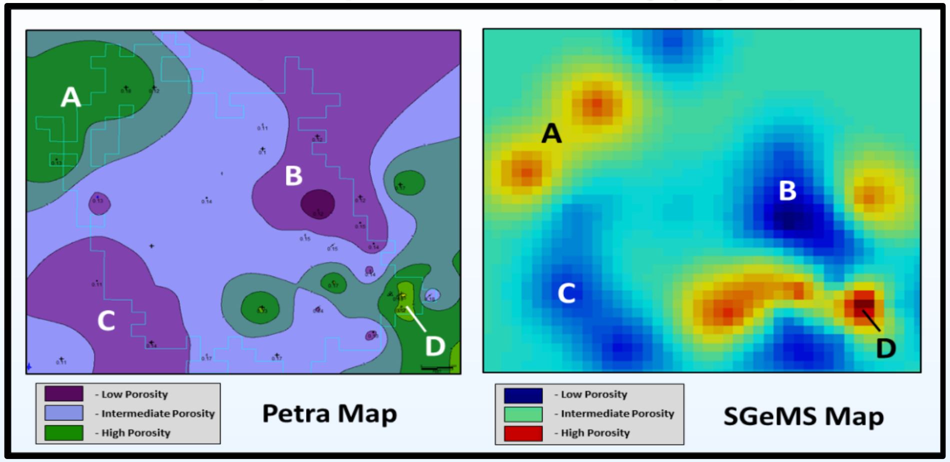
- **Tertiary/ Quaternary** Model Layers (Midway-Surface):
  - Predicted porosity from neural net not successful due poor log data quality/ missing data.
  - A single porosity and permeability value applied for each model layer over the entire study area
- **Cretaceous** Model Layers (Donovan to Selma):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

Formation	# Model Layers	Perm Transform
Alluvium	1	500,000 mD
Citronelle	1	17,500 mD
Miocene	1	34,600 mD
Chickasawhay	1	1,100 mD
Vicksburg	1	0.032 mD
Jackson	1	0.032 mD
Claiborne	3	0.032 to 386 mD
Wilcox	5	3.09E-5 to 660 mD
Midway	5	3.24E-6 to 1,680 mD
Selma	20	$K = 0.0033(e^{(0.1735*\phi)})$
Eutaw	20	$\text{Log } k = (0.13*\phi)-1.56$
Upper Tuscaloosa	50	$\text{Log } k = (0.18*\phi)-2.92$
Tuscaloosa Marine Shale	10	$k = (6E-19)*(\phi^{12.52})$
Lower Tuscaloosa	30	$k = (2E-14)*(\phi^{12.176})$
Washita	60	$k = (1E-9)*(\phi^{8.257})$
Fredericksburg	60	$k = (1E-9)*(\phi^{8.257})$
KWF Confining	5	1.21E-4 mD
Upper Paluxy	60	$k = (4E-10)*(\phi^{9.0365})$
Lower Paluxy	20	$K = 0.0004(e^{(0.6242*\phi)})$
Mooringsport	5	$K = 0.0033(e^{(0.1735*\phi)})$
Ferry Lake Anhydrite	1	5.5E-05 mD
Donovan	40	$K = 0.002(e^{(0.4873*\phi)})$

Heterogeneity Modeling

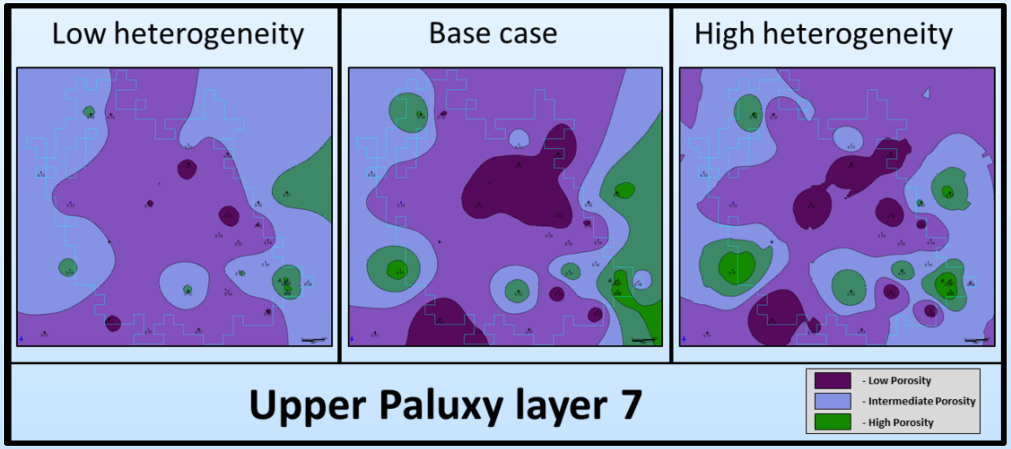
- Heterogeneity was modeled over the study area using geostatistics
  - Generating realizations was tedious
  - (least squares) Kriging methods within *Petra* approximated geostatistics.

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.

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

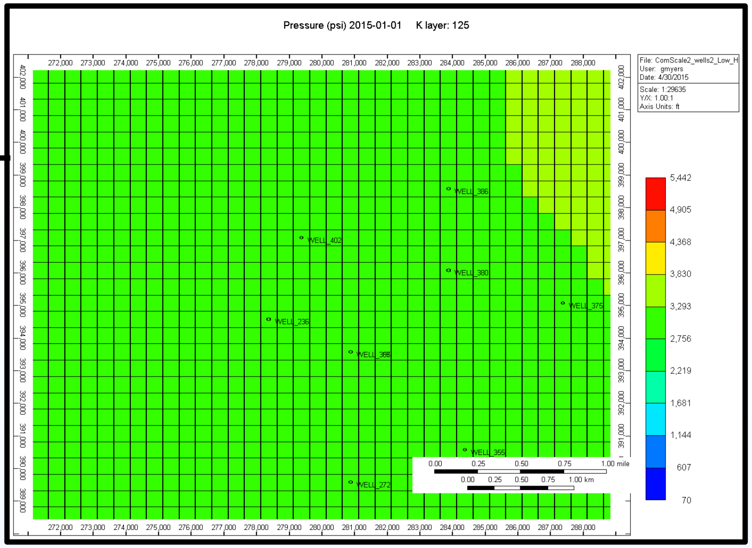


Heterogeneity Scenario	Surface Style Contouring
Base Case	Highly connected features
Low Heterogeneity	Minimum Curvature
High Heterogeneity	Disconnected Features

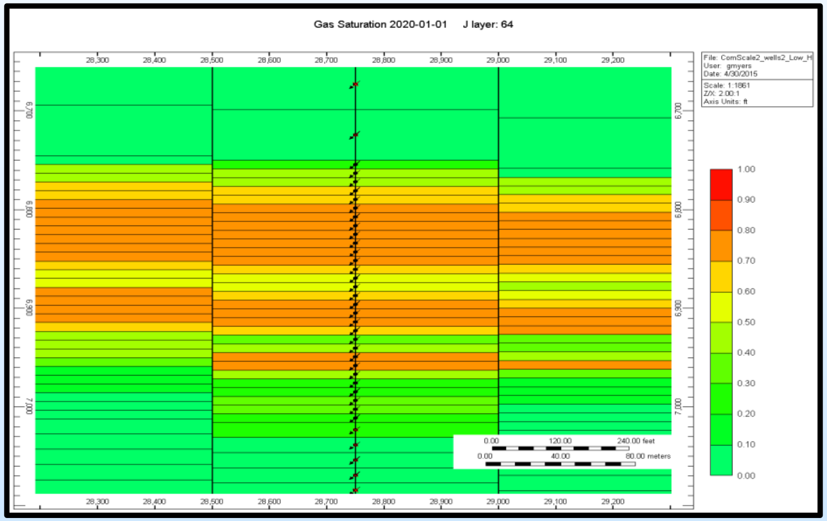
Large Scale Model

- The model has been executed and run on several layers to for testing and comparison:
  - Baseline, Pre-Injection Pressure in Model Layer at the top of the Paluxy Formation
  - Post-Injection Pressure Distribution in Model Layer at the top of the Paluxy Formation

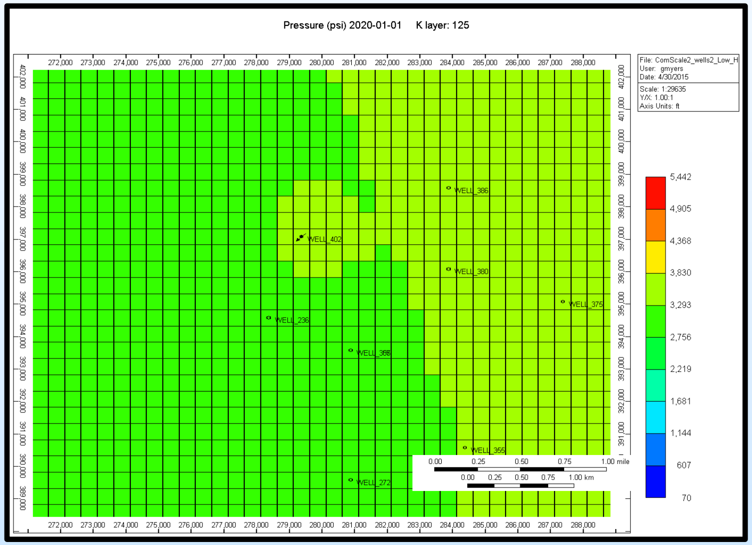
Injection of 4.25 Million Tons of CO_2 into the Formation at the rate of 2,330 tons/day over a period of 5 years



Pre-injection pressure distribution



Cross Section near the Well Bore Showing the Vertical Distribution of Gas Saturation following Injection



Post-injection pressure distribution

Accomplishments to Date

- Completed geologic model.
- Successful implementation of the Neural Network approach to predict porosity
- Generated low, base and high heterogeneity input models.
- Completed simulation models, handed over to UAB for testing, debugging and execution.
- Time running 4.8 million grid cell model has been reduced from 230 hours to 30 hours (40 years injection).
- Laboratory measurements/estimates of:
  - effective permeability,
  - minimum capillary displacement pressure, and
  - leakage impact.
- OSU has completed petrographic and x-ray diffraction analysis of Paluxy core.
- An M.S. thesis was written on the Paluxy Sand, titled, “Geologic Characterization of a Saline Reservoir for Carbon Sequestration: The Paluxy Formation, Citronelle Dome, Gulf of Mexico Basin, Alabama”.

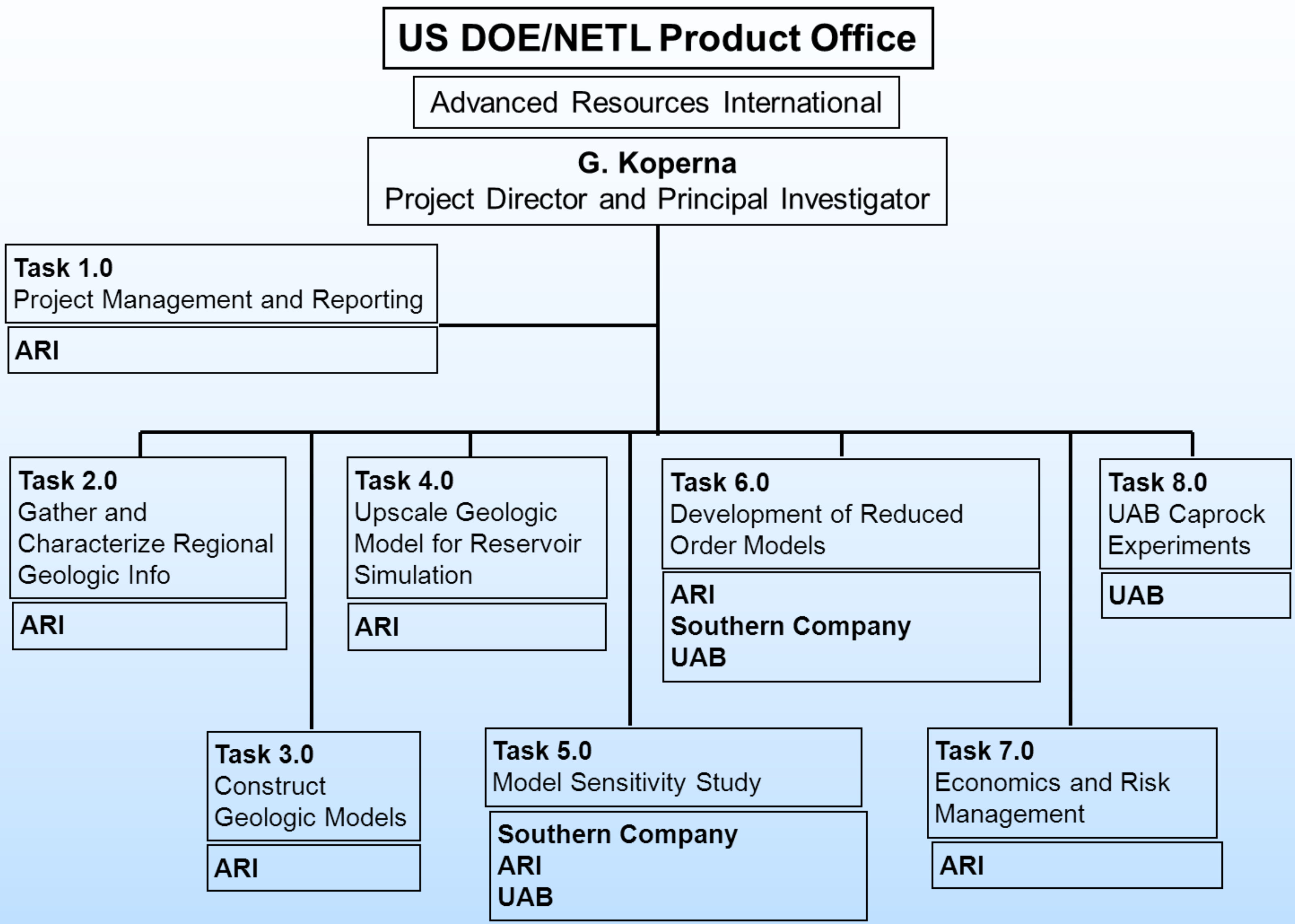
Key Findings/Lessons Learned

- 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

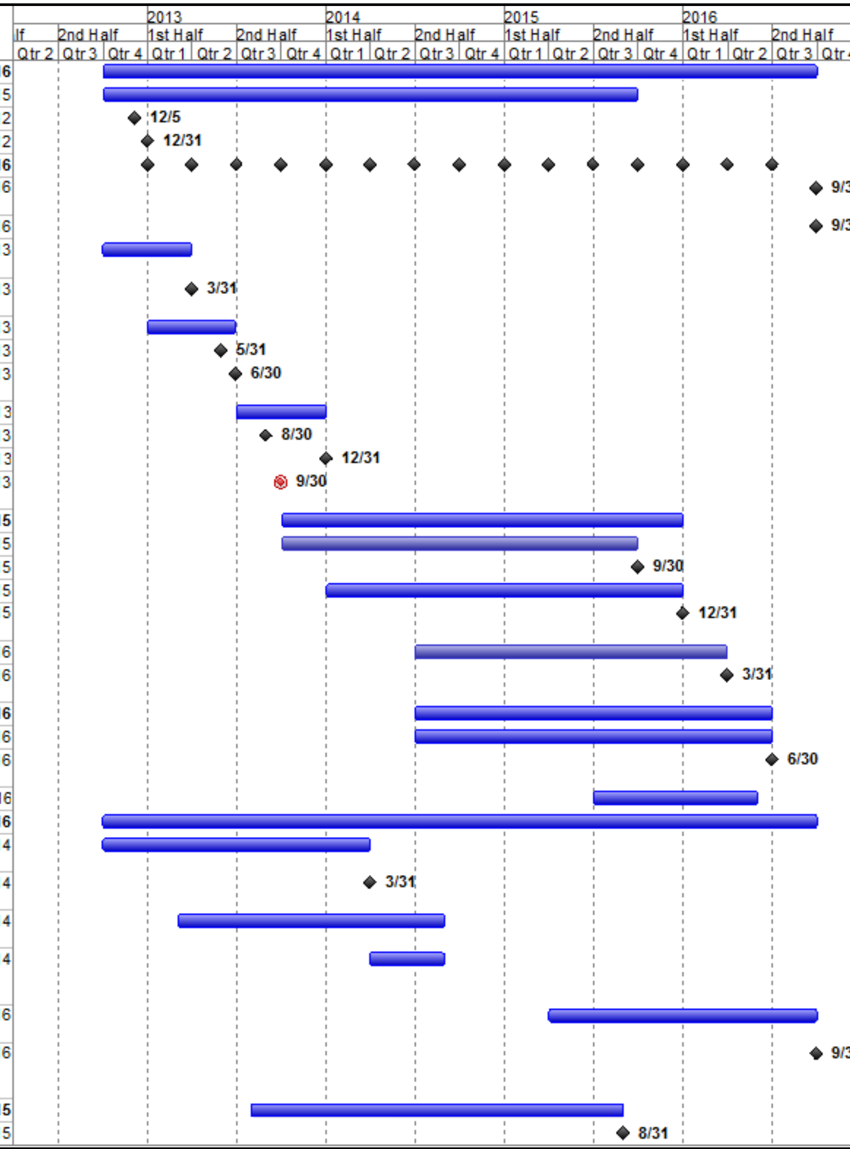
- **Sensitivity Study**: Will explore sensitivities such as well design and lateral heterogeneity to maximize storage capacity while minimizing the operation's footprint.
- **Optimization**: Will incorporate economic and risk management considerations which will be overlain on the modeling results to 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	**Tue 10/2/12**	**Fri 9/30/16**
Subtask 1.1 – Project Management Plan	Tue 10/2/12	Wed 9/30/15
Deliverable 1.1 – Report, Project management plan	Wed 12/5/12	Wed 12/5/12
Deliverable 1.2 – Kickoff Meeting	Mon 12/31/12	Mon 12/31/12
Deliverable 1.3 – Report, Quarterly progress reports	**Tue 1/1/13**	**Fri 9/30/16**
Deliverable 1.4 – Best Practices Manual for CO2 storage in the U.S. Eastern Gulf Coast	Fri 9/30/16	Fri 9/30/16
Deliverable 1.5 – Final project reports	Fri 9/30/16	Fri 9/30/16
Task 2: Gather and Characterize Regional Geologic Information	Mon 10/1/12	Sun 3/31/13
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	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	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	**Wed 10/2/13**	**Thu 12/31/15**
Subtask 5.1 – Injection Scenario Simulations	Wed 10/2/13	Wed 9/30/15
Deliverable 5.1 – Meeting, Modeling data review and critique	Wed 9/30/15	Wed 9/30/15
Subtask 5.2 – Visualization of Simulation Results	Thu 1/2/14	Thu 12/31/15
Deliverable 5.2 – Report, Modeling results and storage efficiency factors	Thu 12/31/15	Thu 12/31/15
Task 6: Development of Scoping/Screening Level Models	Tue 7/1/14	Thu 3/31/16
Deliverable 6.1 – Report, Reduced order model and code module	Thu 3/31/16	Thu 3/31/16
Task 7: Economics and Risk Management	**Wed 7/2/14**	**Thu 6/30/16**
Subtask 7.1 – Economic Assessment	Wed 7/2/14	Thu 6/30/16
Deliverable 7.1 – Report, Economic and risk management modeling results	Mon 8/31/15	Thu 6/30/16
Subtask 7.2 – Risk Assessment	Thu 7/2/15	Tue 5/31/16
Task 8: UAB Task - Ensuring Containment	**Mon 10/1/12**	**Fri 9/30/16**
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 3/4/13	Sat 8/30/14
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	Sat 8/30/14
Subtask 8.3 Evolution of Cap Rock Properties in the Presence of Carbon Dioxide	Thu 4/2/15	Fri 9/30/16
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	Fri 9/30/16	Fri 9/30/16
Task 9: Depositional Systems Analysis	**Thu 8/1/13**	**Mon 8/31/15**
Depositional System Analysis	Mon 8/31/15	Mon 8/31/15



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.

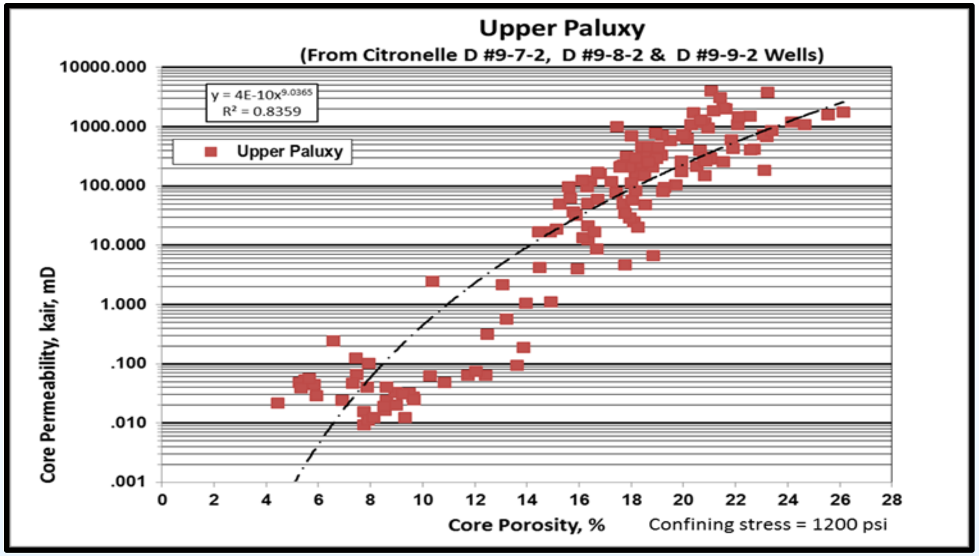
- *Geologic Characterization of a Saline Reservoir for Carbon Sequestration: The Paluxy Formation, Citronelle Dome, Gulf Of Mexico Basin, Alabama*, A. T. Folaranmi, M.S. Thesis, 2015 Oklahoma State University, Stillwater, Oklahoma, May 2015.

- *Developing Porosity with a Neural Network Application for Geologic Modeling in an Active Oil Field (EOR*), H. Jonsson, G.J. Koperna, oral presentation, 2014 Pittsburgh Coal Conference, Pittsburgh, Pennsylvania, October 6-9 2014.

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

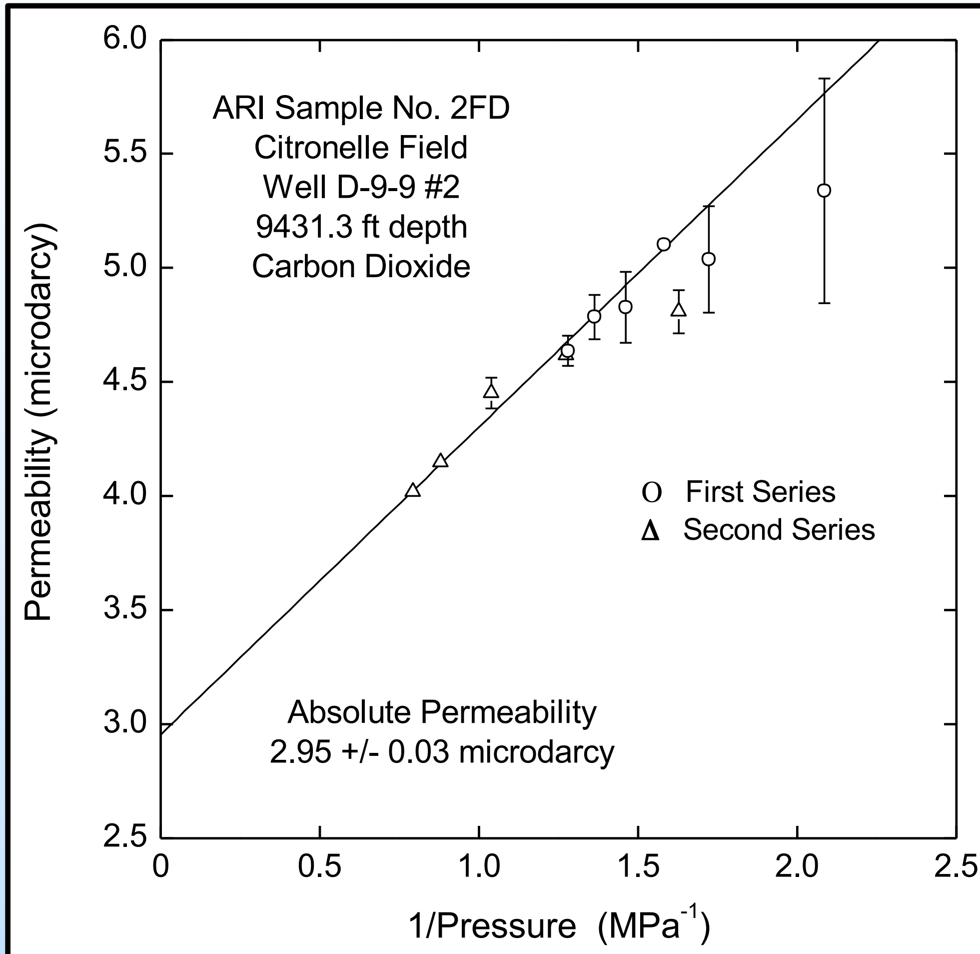
Core Porosity, %	Upper Paluxy Core Permeability, mD	Core Porosity, %	Upper Paluxy Core Permeability, mD
6	0.004	**24**	**1,186.7**
8	0.058	**26**	**2,446.1**
12	**2.26**	28	4,778.6
16	**30.4**	30	
20	**228.5**	32	
22	**540.6**	34	

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.



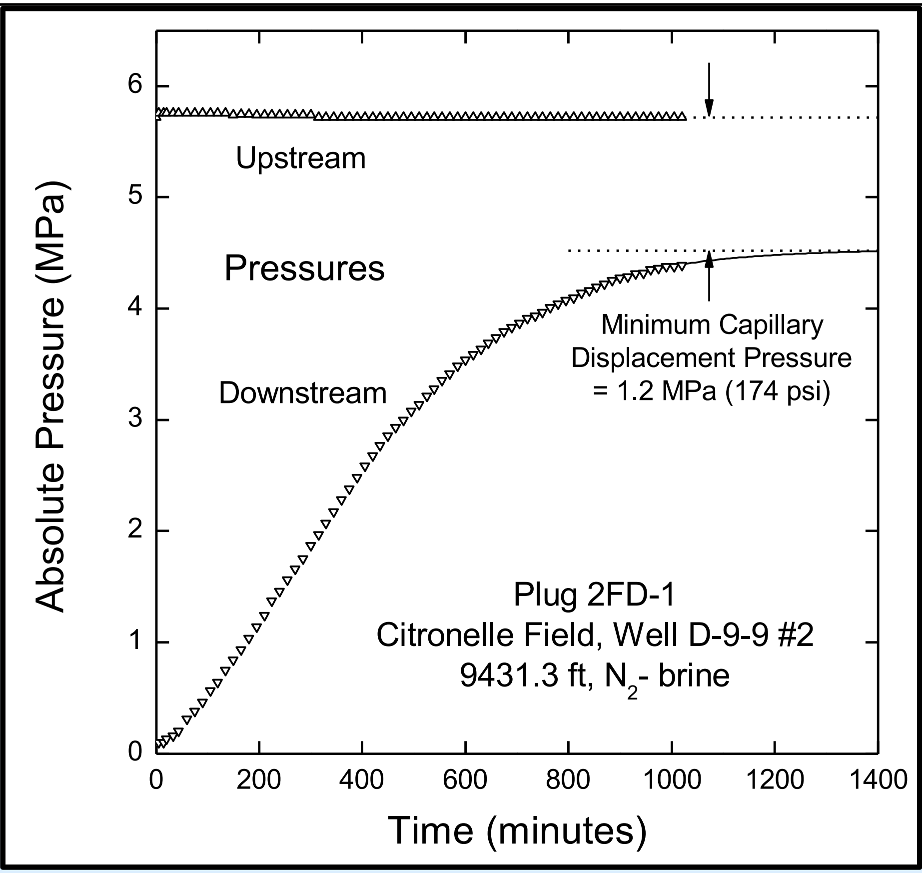
Determination of Minimum Capillary Displacement Pressure*†

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.

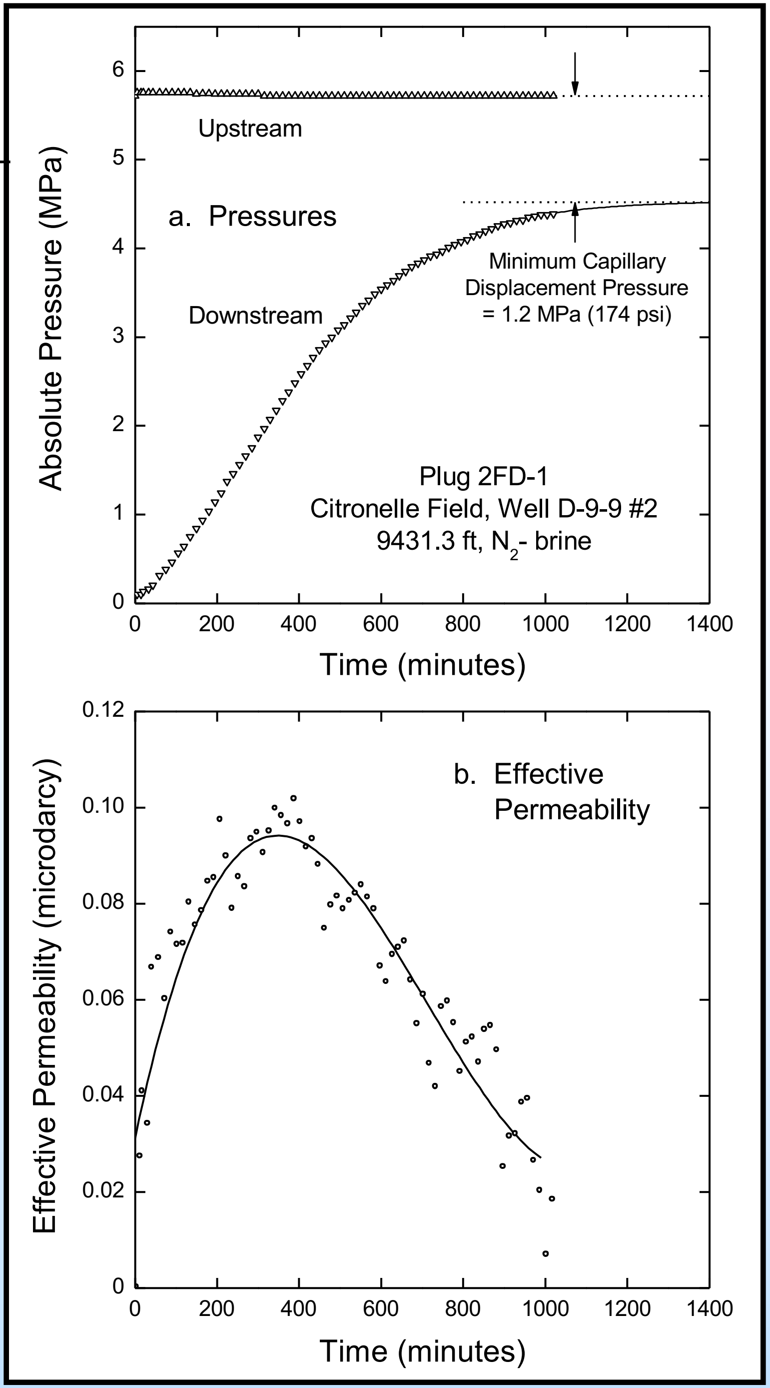
*Hildenbrand, A., S. Schlömer, and B. M. Krooss, "Gas breakthrough experiments on fine-grained sedimentary rocks." *Geofluids*, **2002**, *2*, 3-23.
†Hildenbrand, A., S. Schlömer, B. M. Krooss, and R. Littke, "Gas breakthrough experiments on pelitic rocks: comparative study with N_2, CO_2 and CH_4,"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



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*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.

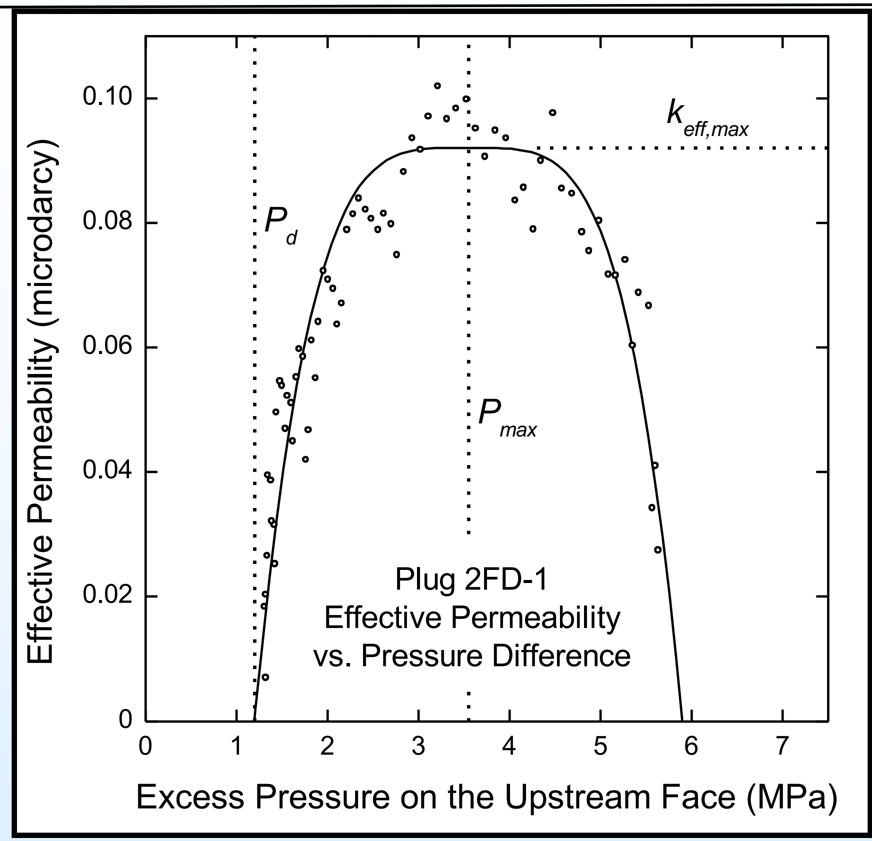
The minimum capillary displacement pressure, P_d (1.2 MPa, 174 psi) is the pressure at breakthrough, on the left.

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).

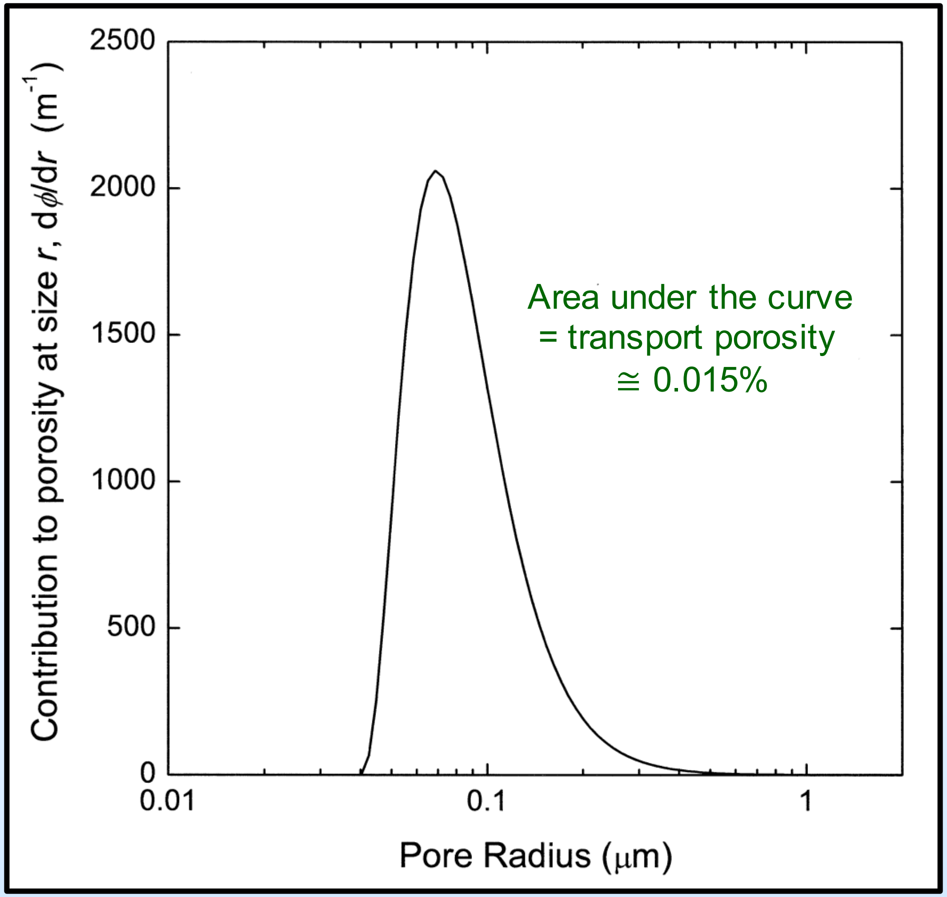
Rate of change of porosity, ϕ, with increase

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

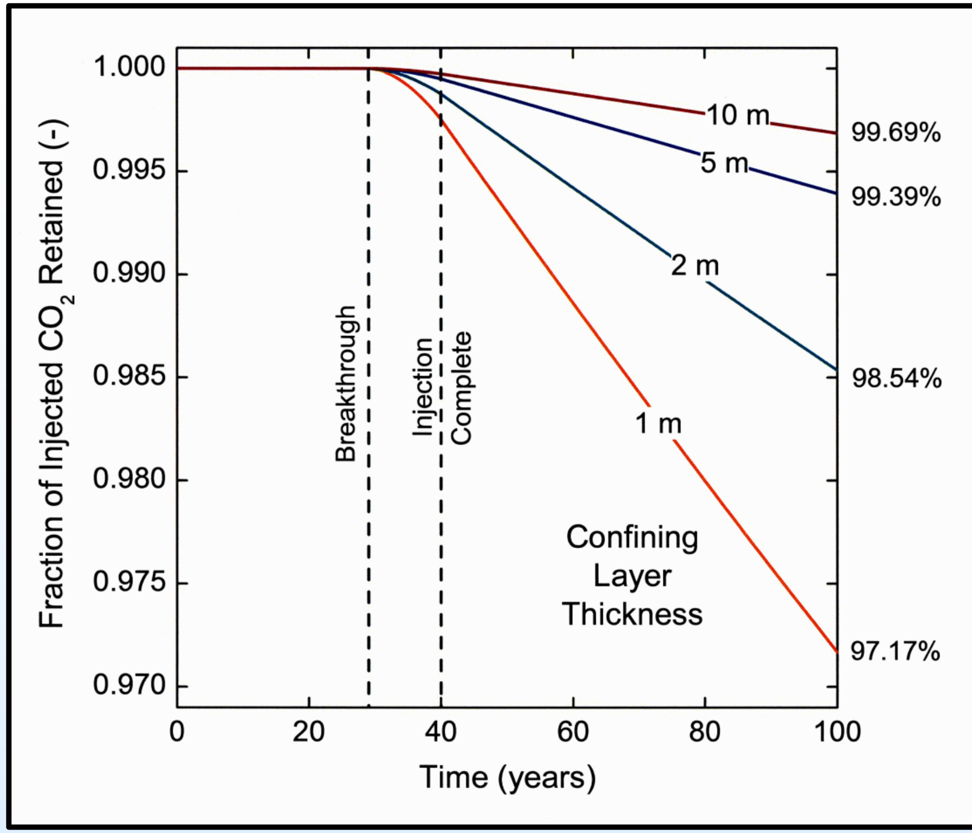
Leakage begins when the excess pressure exceeds the minimum capillary displacement pressure.

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