

# USING RESERVOIR ARCHITECTURE TO MAXIMIZE CO<sub>2</sub> STORAGE CAPACITY

David E. Riestenberg, George J. Koperna,  
and Vello A. Kuuskraa, Advanced  
Resources International, Inc.

Richard A. Esposito, Southern Company  
Services, Inc.



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# Presentation Outline

- Study Background
- Site Geology
- Model Cases
- Results
- Conclusions

# Background

Because of its natural buoyancy, injected CO<sub>2</sub> tends to migrate to the crest of a saline reservoir and rapidly migrate outward, resulting in :

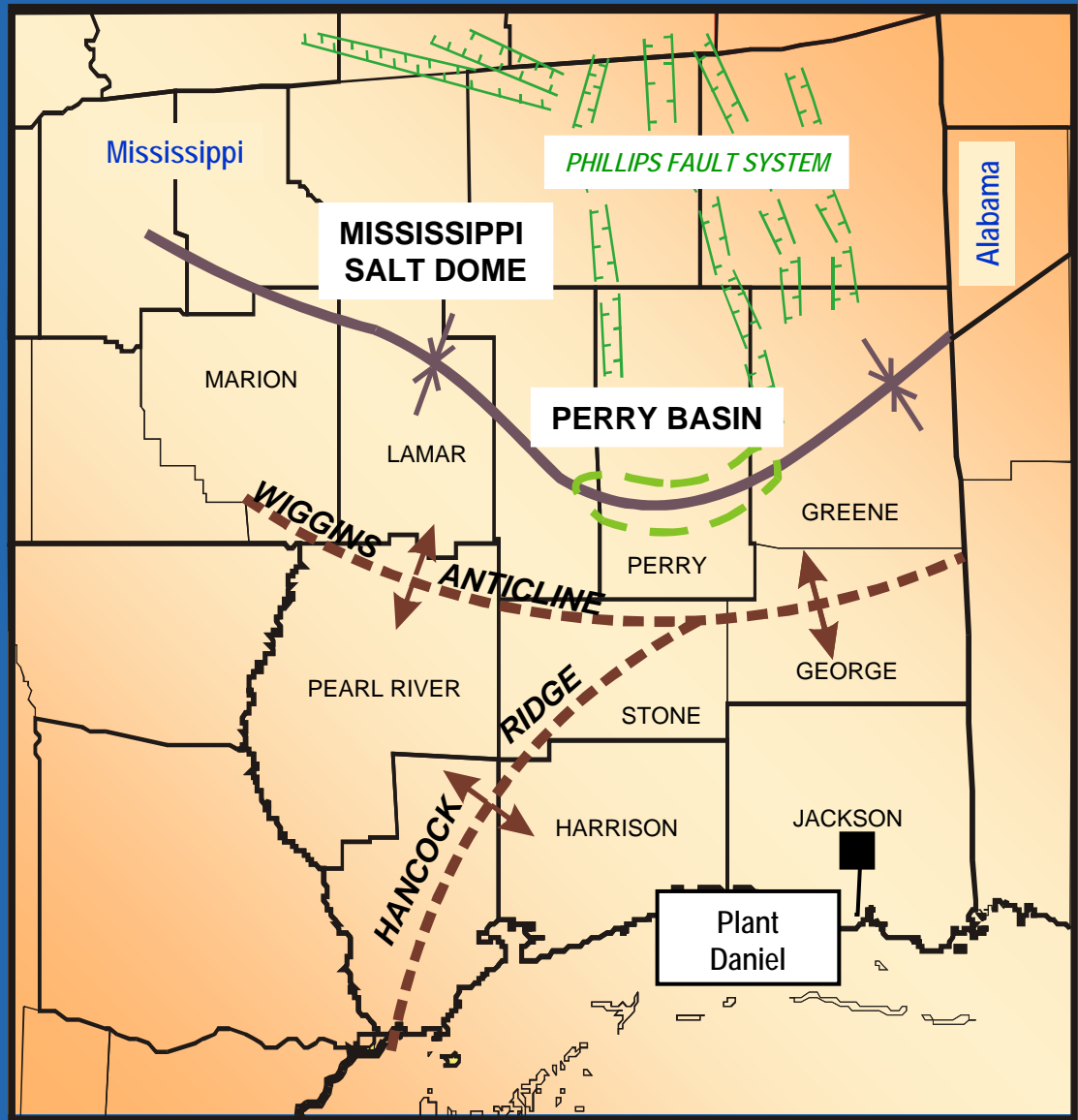
- Limited practical storage capacity
- Increased time until immobilization
- Increased horizontal plume migration

This study explores the impact of a reservoir's internal structure, or "architecture", on these effects using reservoir simulation of CO<sub>2</sub> injection into the Lower Tuscaloosa Formation at the SECARB Saline Reservoir Test Site in Mississippi as the field example.

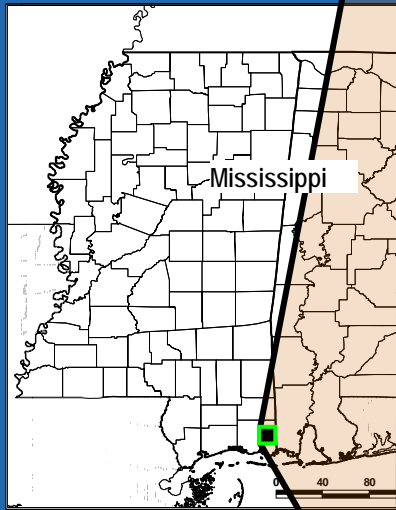
# Mississippi Test Site

The Lower Tuscaloosa Formation below Southern Company's Plant Daniel along the Mississippi Gulf Coast appears to be a safe, secure CO<sub>2</sub> storage site and formation:

- Competent, regionally extensive caprock and seal(s)
- Multiple shallower "safety zones"
- Updip structural confinement
- High CO<sub>2</sub> storage capacity with favorable reservoir properties
- Favorable hydrological system
- Protection of potable and low salinity water



# Mississippi Power Company's Victor J. Daniel Power Plant



# Saline Reservoir Units and Seals

(SE Mississippi)

## Potential CO<sub>2</sub> Storage Units

- Lower Tuscaloosa Massive Sand Unit (U. Cretaceous)
- Dantzler Formation (L. Cretaceous)

## Confining Units (Seals):

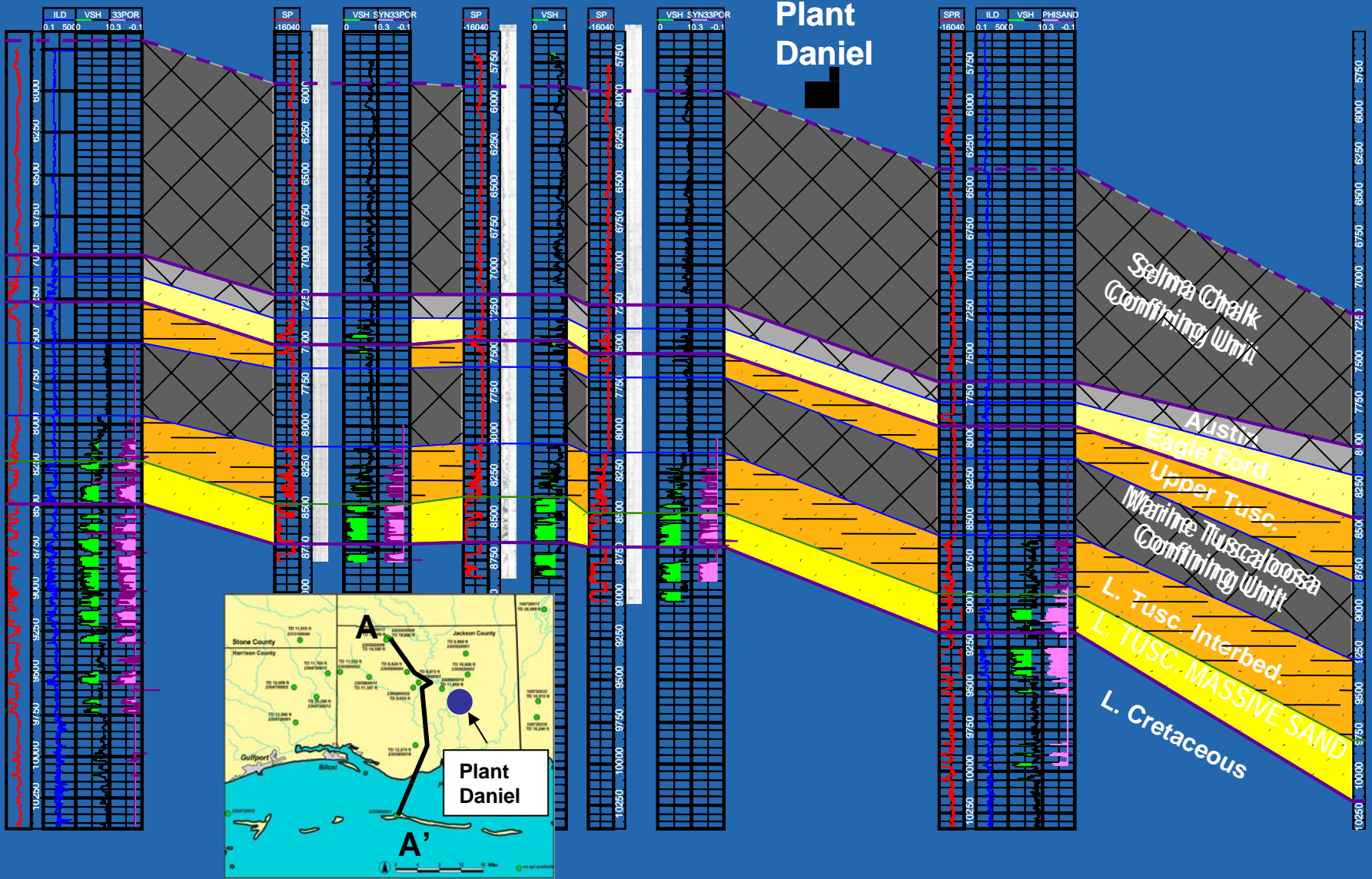
- Marine Tuscaloosa
- Austin Formation
- Selma Chalk/Navarro Fm.
- Midway Shale

System	Series	Stratigraphic Unit	Sub-Units	Hydrology	
Tertiary	Pliocene		Citronelle Fm.	Freshwater Aquifers	
			Graham Ferry Fm.		
	Miocene	Misc. Miocene Units	Pascagoula Fm.	Freshwater Aquifers	
			Hattiesburg Fm.		
			Catahoula Fm.		
	Oligocene	Vicksburg		Saline Reservoir	
			Red Bluff Fm.	Minor Reservoir	
	Eocene		Jackson	Saline Reservoir	
			Claiborne	Saline Reservoir	
			Wilcox	Saline Reservoir	
Paleocene		Midway Shale	Confining unit		
Cretaceous	Upper	Selma Chalk	Navarro Fm.	Confining unit	Additional Confining Zone
			Taylor Fm.		
		Eutaw	Austin Fm.	Confining unit	
			Eagle Ford Fm.	Saline Reservoir	
	Tuscaloosa Group	Upper Tusc.	Minor Reservoir		
		Marine Tusc.	Confining unit		
		Lower Tusc. Interbeds Massive Sand	Saline Reservoir		
	Lower	Washita – Fredricksburg	Dantzler Fm.	Saline Reservoir	Confining Zone
“Limestone Unit”				Injection Zone	

# North-South Geologic Cross Section

A(N)

A'(S)

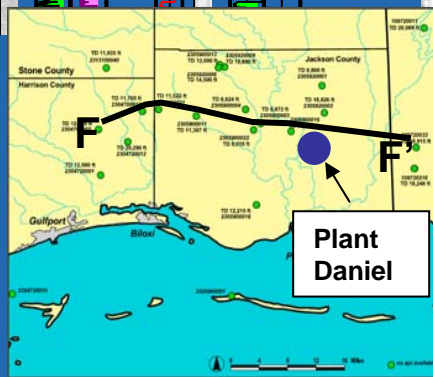
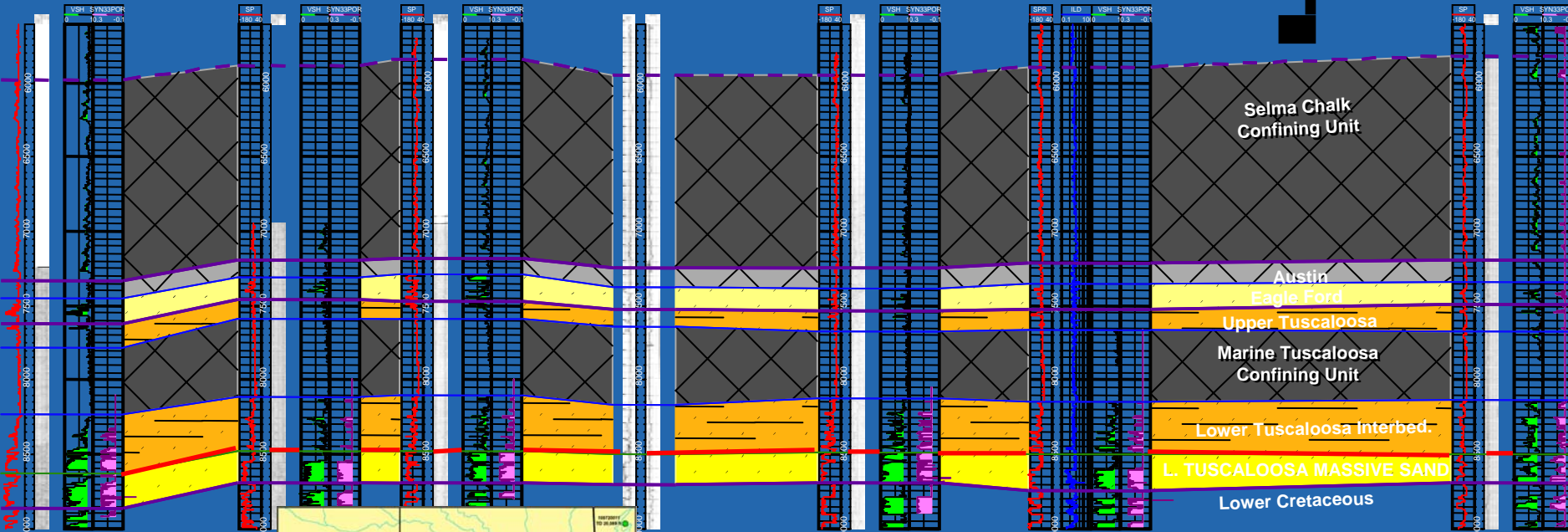


# West-East Geologic Cross Section

F(W)

F'(E)

Plant Daniel



# Modeling Assumptions

Thickness	Sand	187 ft
	Shale	77 ft
Porosity	Sand (from logs)	20%
	Shale (assumed)	5%
Permeability	Sand (from logs)	Hz- 596 md, Vert – 396 md
	Shale (assumed)	$1 \times 10^{-6}$ md
Water Saturation		100%
Salinity		200,000 ppm
Pressure Gradient		0.459 psi/ft
Temperature		229 °F
Dip		0°
Pore Volume Trapping		15%

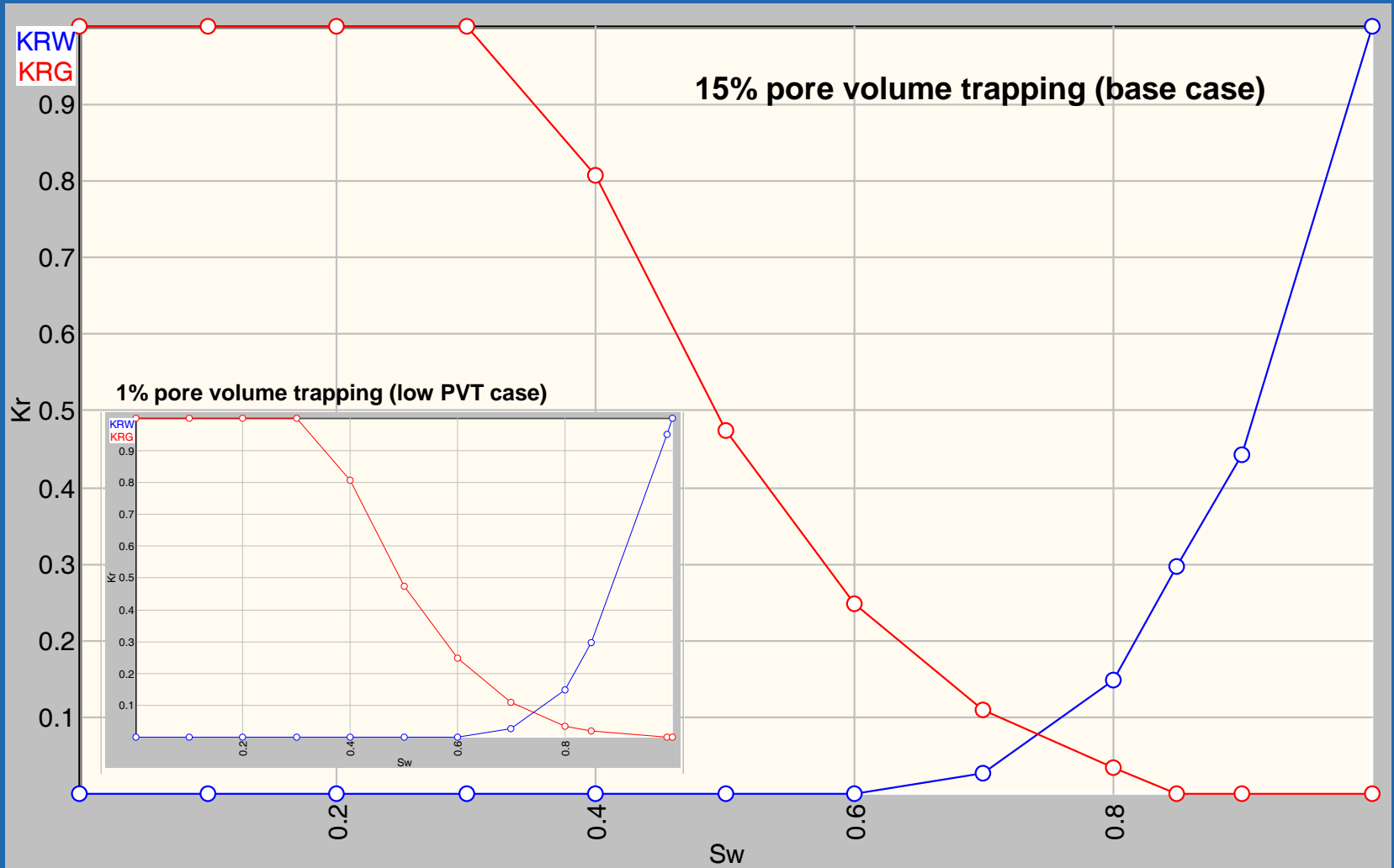
# Model Cases

1. **Homogeneous 'Massive' Sandstone Body** - 100,000 tonnes (1.72 Bcf) of CO<sub>2</sub> per year for four years, equilibrate for 100 years. For this case and all of the following, except case #3, we assumed a 15% value for pore volume trapping.
2. **'Massive' Sandstone with Shale "Baffles"** – 100,000 tonnes (1.72 Bcf) of CO<sub>2</sub> per year for four years. The CO<sub>2</sub> plume was then allowed to equilibrate for 100 years. reservoir with multiple sand bodies and shale "baffles" modeled after the 'Massive' Sandstone reservoir.
3. **Low Pore Trapping** – 100,000 tonnes (1.72 Bcf) of CO<sub>2</sub> per year for four years, equilibrate for 100 years. Decrease the reservoir's pore volume trapping from 15% to 1%. This relative permeability adjustment allows gas to become mobile at a water saturation value of 99% (1% gas saturation) instead of 85%.

# Model Cases

4. **“Leaky” Baffle** – 100,000 tonnes (1.72 Bcf) of CO<sub>2</sub> per year for four years, equilibrate for 100 years. To investigate the effect of this phenomenon on CO<sub>2</sub> migration, the permeability of one shale baffle was increased to 1 md. This zone is 1 ft thick.
5. **Long-Term CO<sub>2</sub> Injection** – cases #1 and #2 were allowed to inject 100,000 tonnes (1.89 Bcf) of CO<sub>2</sub> per year for forty years.

# Relative Permeability

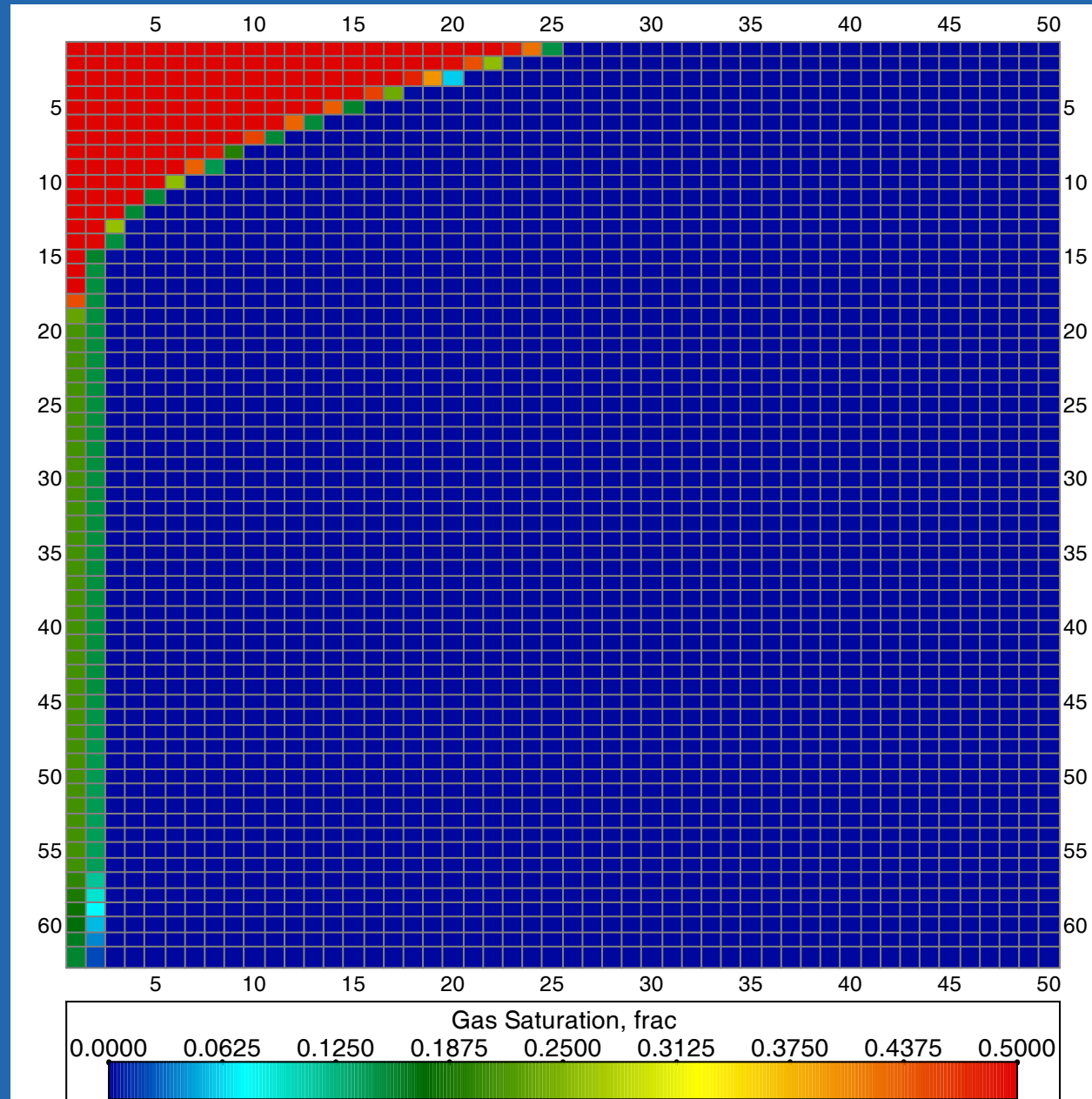


# Case #1: Homogeneous

100,000 Tons Per Year  
CO<sub>2</sub> Injection in Lower  
Tuscaloosa Massive Sand

Maximum plume extent at  
the end of injection period  
(4 years) is **2,500 ft**

One grid block = 100 ft  
horizontally

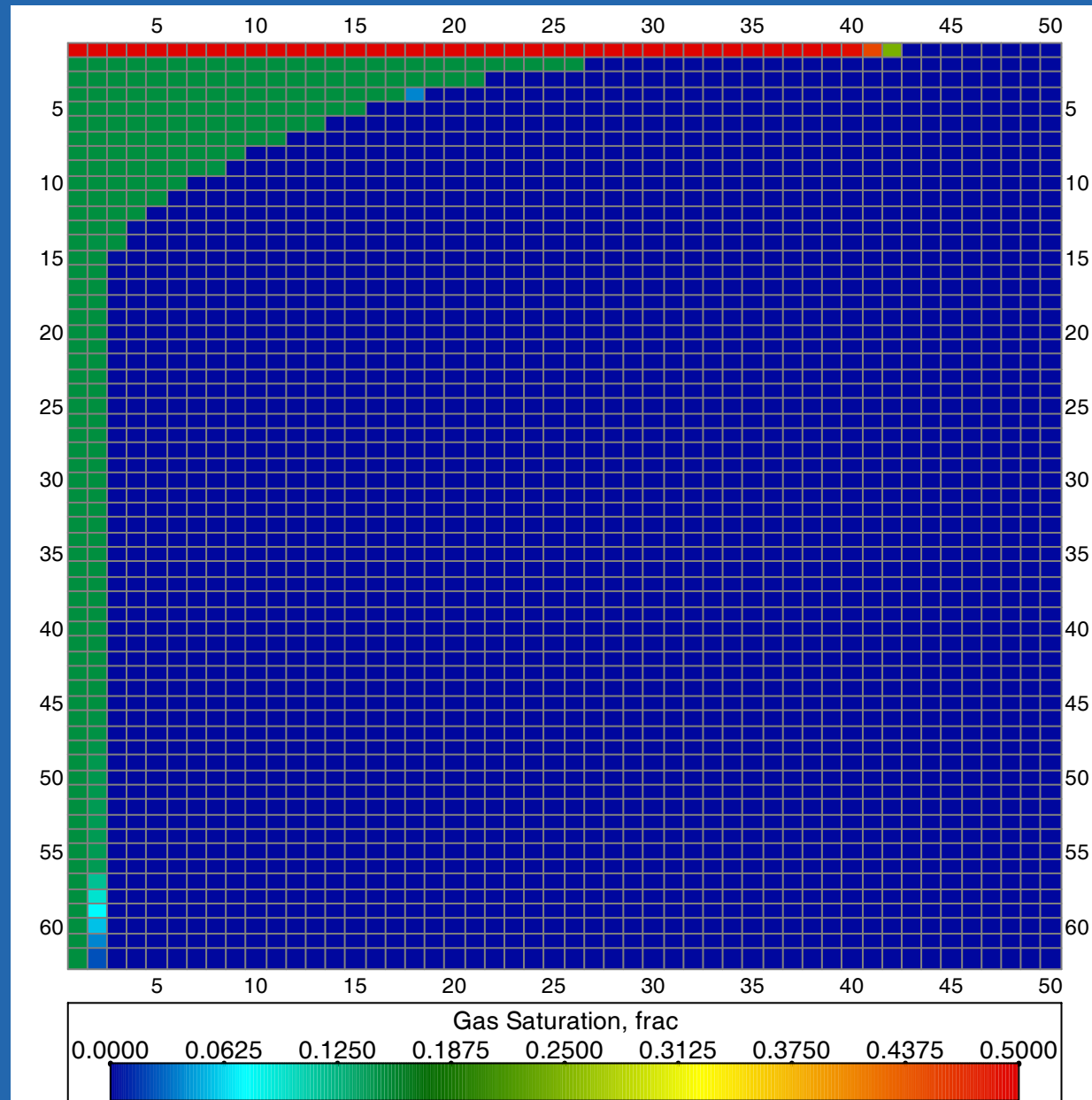


# Case #1: Homogeneous

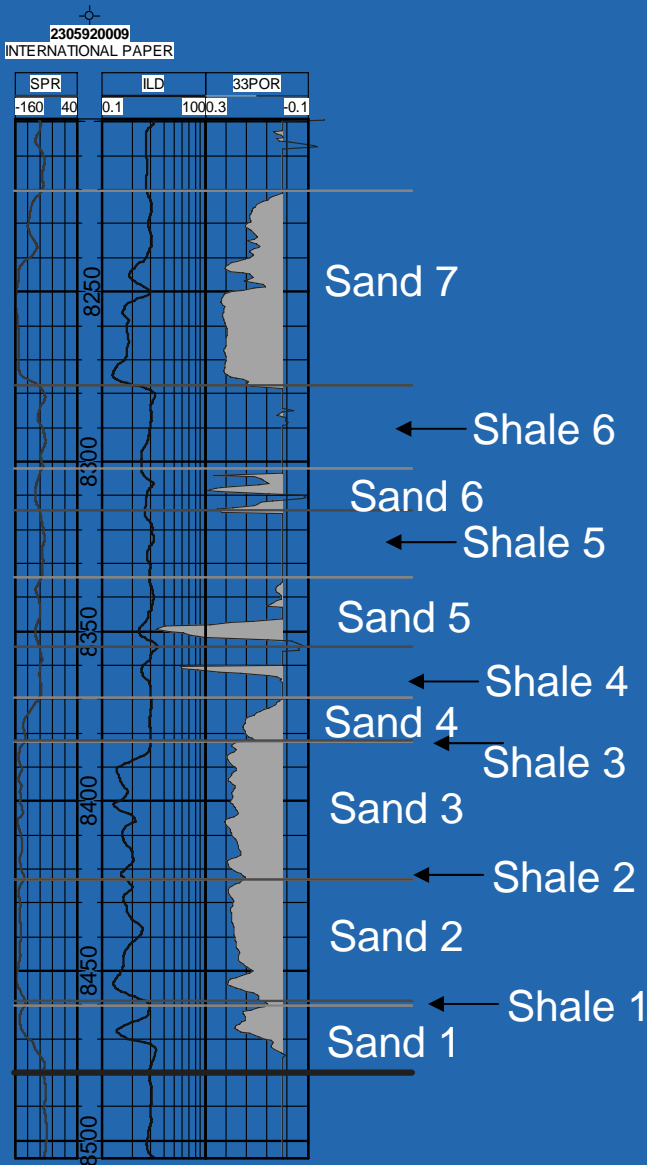
Maximum plume extent at the end of 104 years is **4,300 ft**

## Key Finding:

- Plume stretches **4,300 ft** horizontally along the top of the reservoir



# Case #2: Shale Baffles



The Lower Tuscaloosa Massive Sand Unit on the Mississippi Gulf Coast contains multiple sand packages that vary in thickness from 10 to over 50 ft, for a total net sand of about 190 ft, with by alternating shale breaks over a 300 ft total interval.

The architecture of these shale breaks may result in the baffling of the vertical migration of CO<sub>2</sub> creating multiple plumes that may ultimately migrate less distance horizontally than a plume in a single homogenous sand package.

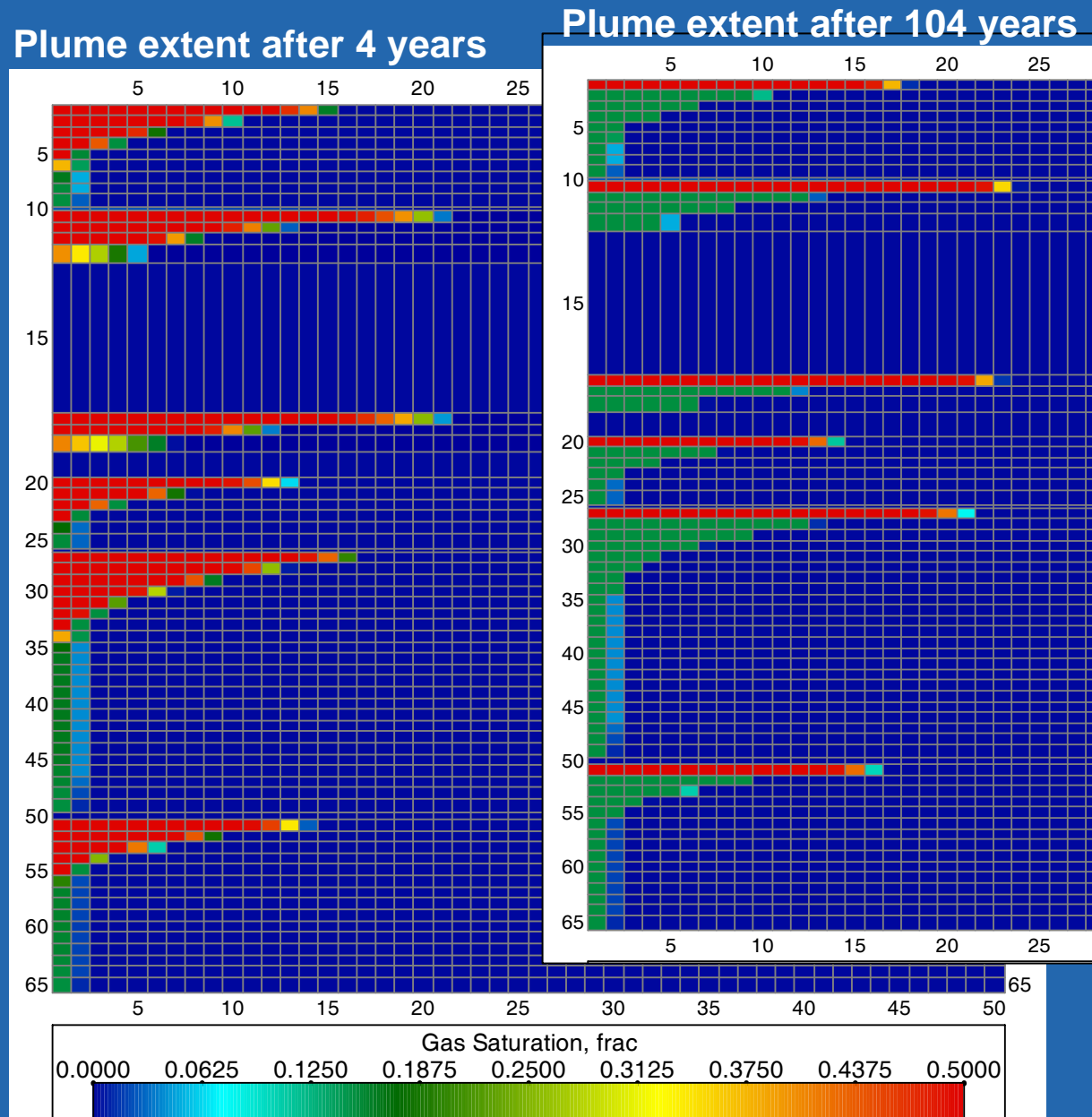
# Case #2: Shale Baffles

Maximum plume extent at the end of injection period (4 years) is **2,100 ft**

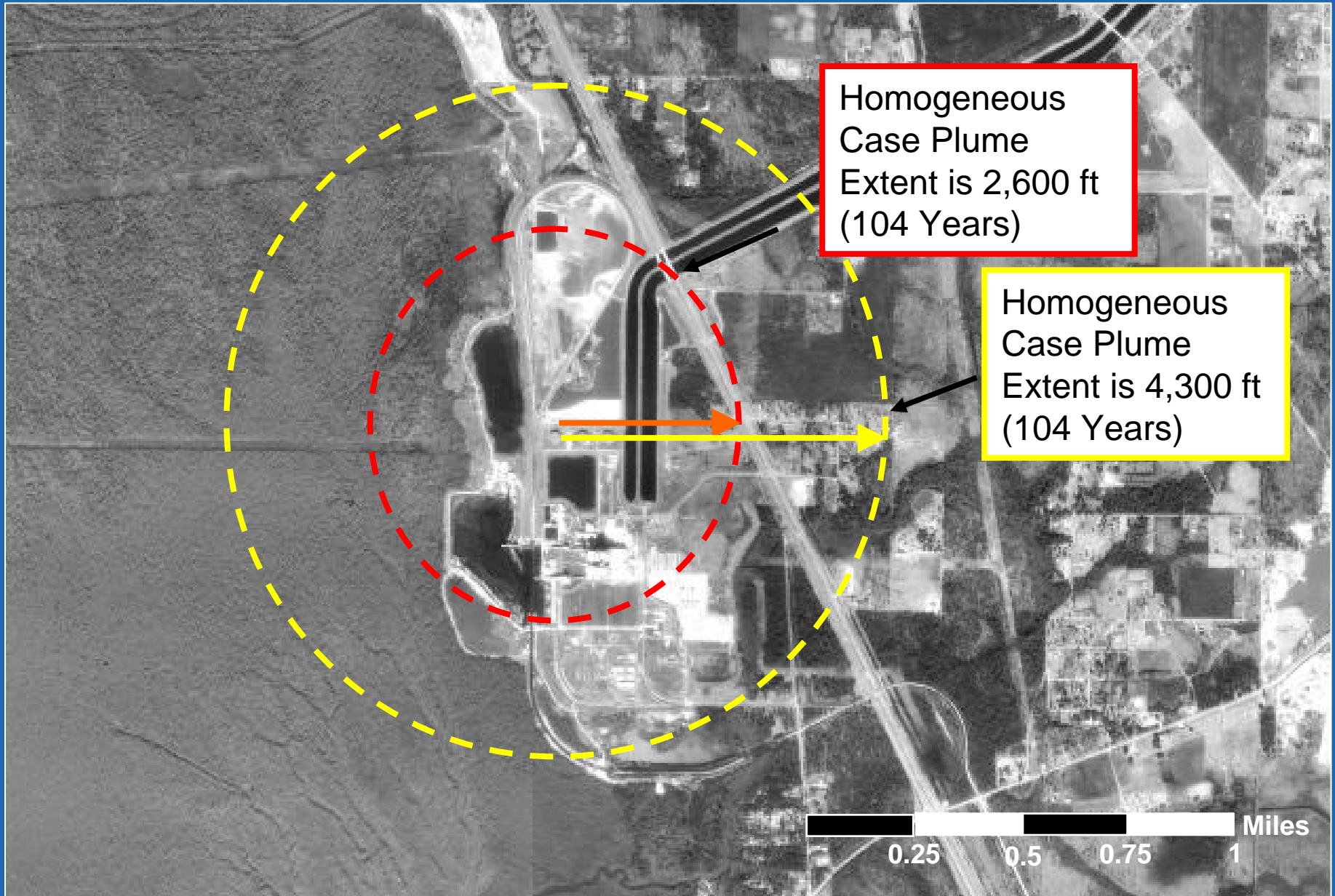
Maximum plume extent at the end of 100 years is **2,600 ft**

## Key Findings:

- Plume stretches an additional 500 feet horizontally along the top of the reservoir after 100 years
- The presence of baffles decreases the plume extent by 1,700 ft versus the homogeneous model



# Plume Extent



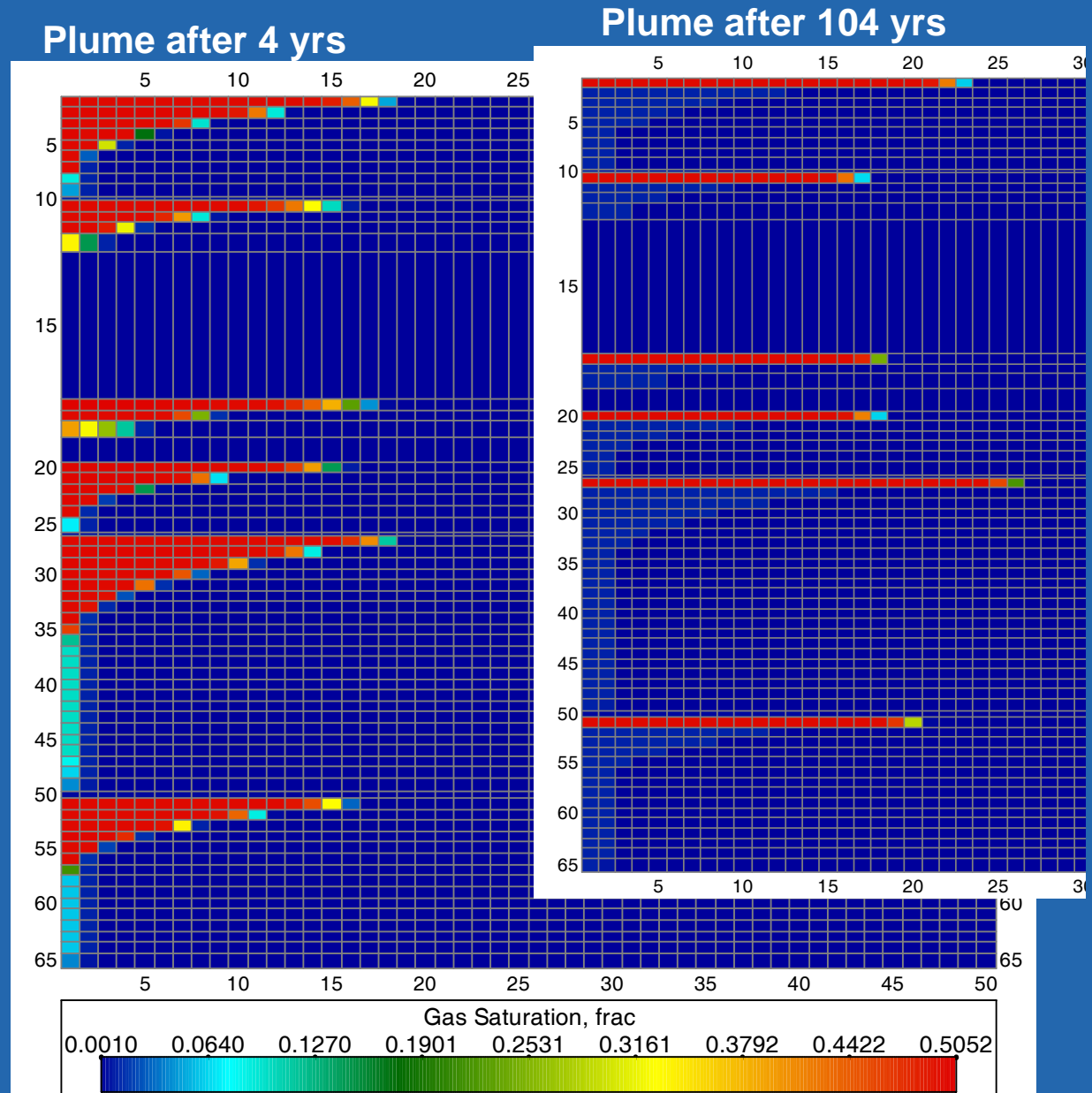
# Case #3: Low PVT

Maximum plume extent at the end of injection period (4 years) is **1,900 ft**

Maximum plume extent at the end of 100 years is **2,700 ft**

## Key Finding:

- A low critical gas saturation increases plume extent by 100 ft versus Case #2



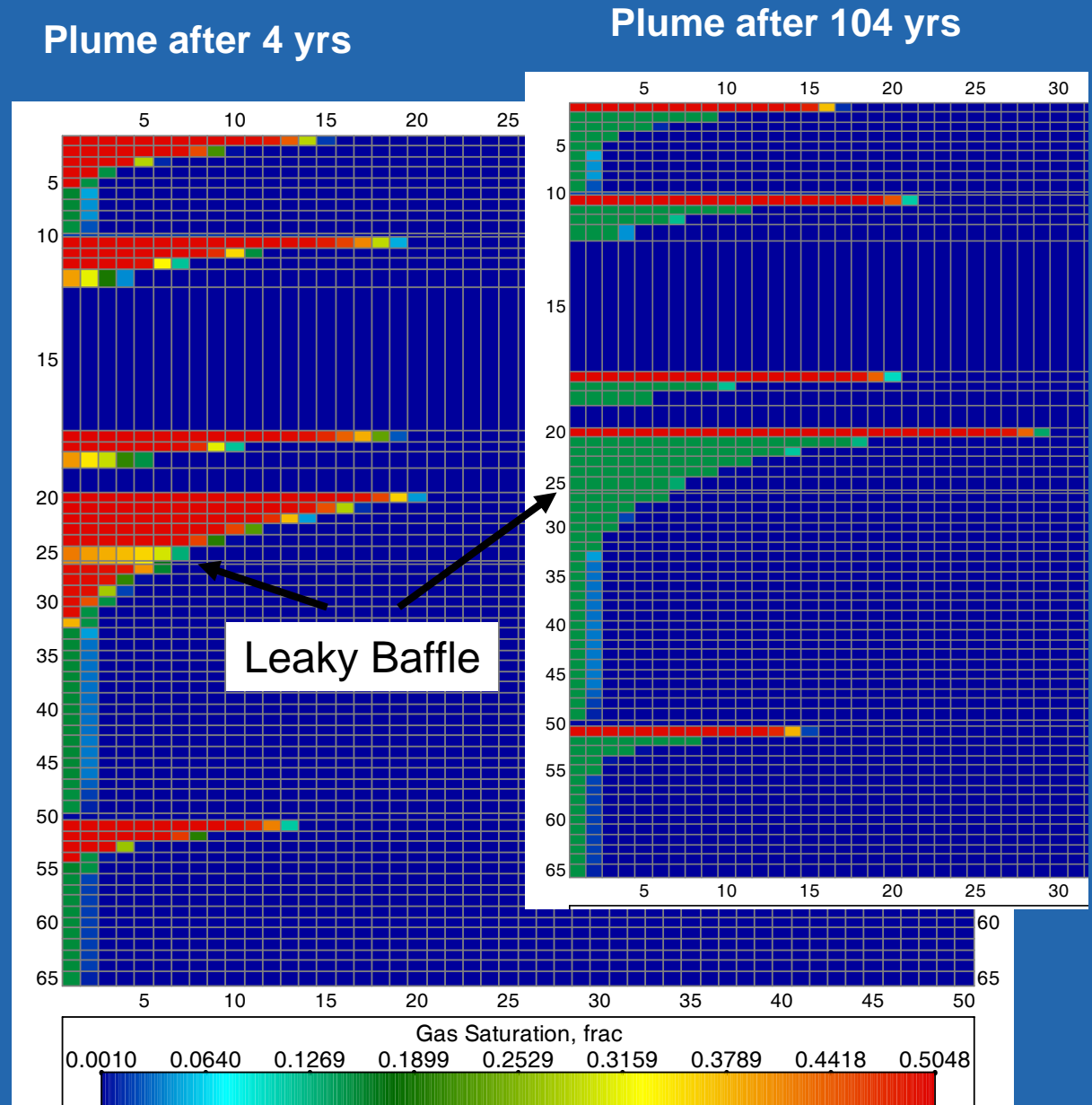
# Case #4: Leaky Baffle

Maximum plume extent at the end of injection period (4 years) is **2,100 ft**

Maximum plume extent at the end of 100 years is **3,000 ft**

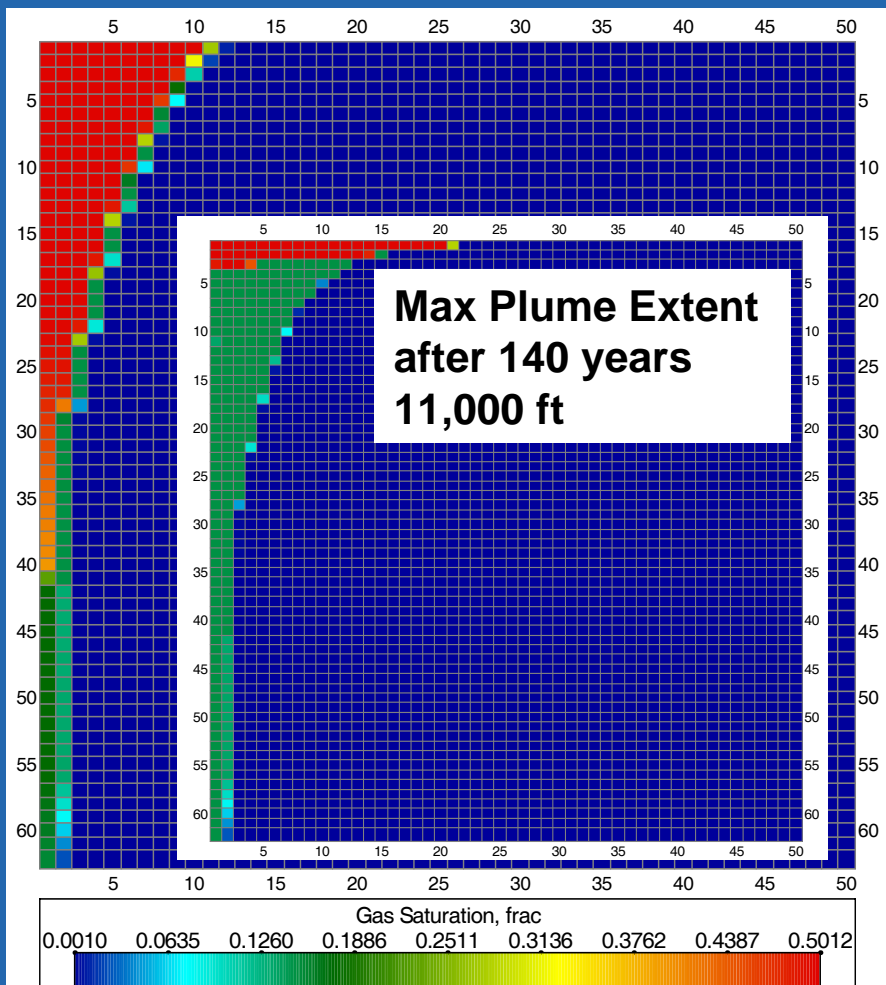
## Key Finding:

- The permeable baffle allows two plumes to join and spread further horizontally, resulting in 400 ft of additional extent versus Case #2

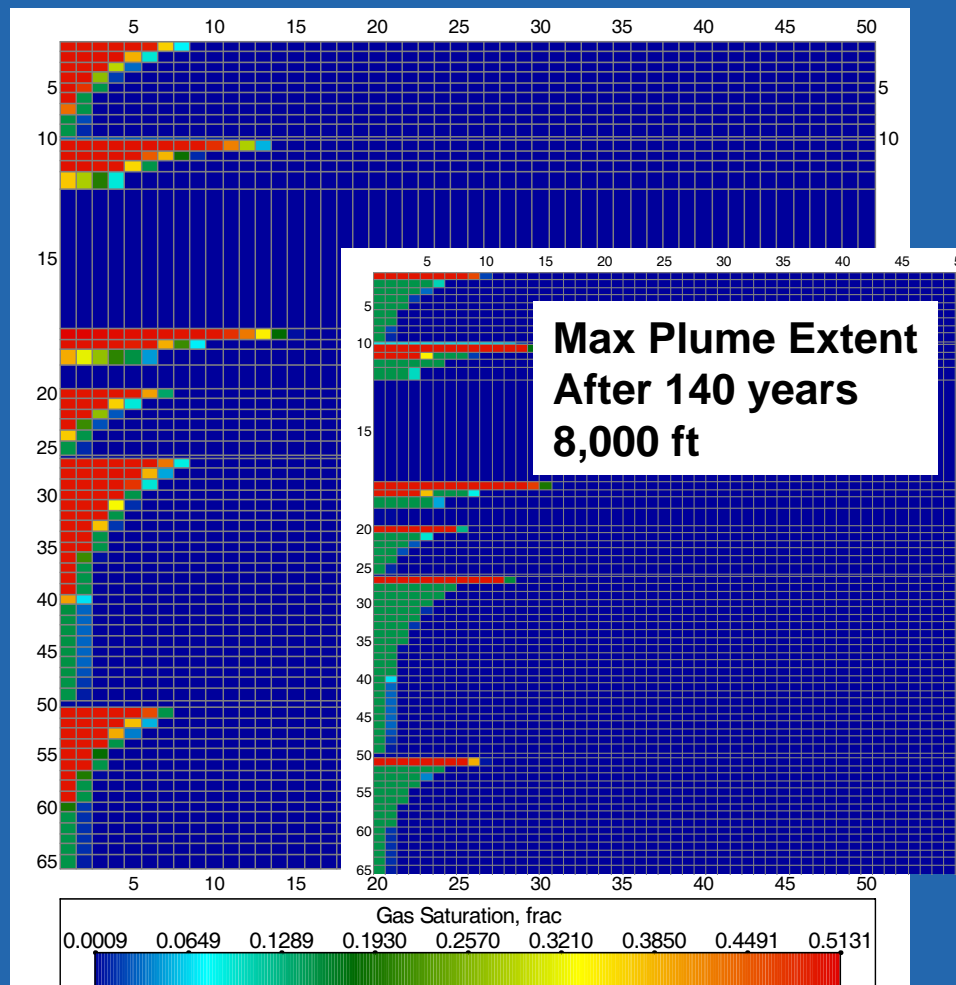


# Case #5: Long-term Injection

## Homogeneous Case



## Baffles Case



# Case Summaries

<b>Case</b>	<b>Max Hz Plume Extent After 100 years, ft</b> <small>(Cases #1-4 = 104 years, Case #5 = 140 years)</small>	<b>Equivalent plume area after 100 year shut-in, acres</b>
Case #1 Homogeneous	4,300	1,330
Case #2 Shale “Baffles”	2,600	490
Case #3 Low Pore Volume Trapping	2,700	530
Case #4 “Leaky Baffle”	3,000	650
Case #5A Long-Term CO <sub>2</sub> Injection - Homogeneous	11,000	8,730
Case #5B Long-Term CO <sub>2</sub> Injection – Shale “Baffles”	8,000	4,620

# Conclusions

- The presence of “baffles” in a saline sandstone reservoir will act to force injected CO<sub>2</sub> to contact more of the reservoir brine system, resulting in a plume of reduced areal extent as compared to a plume created by injection into a homogeneous reservoir.
- In a “baffled” reservoir, the degree of pore volume trapping significantly alters the vertical structure of the plume, with nearly all of the injected CO<sub>2</sub> moving vertically and then outward at the base of the “baffle”. This condition may be worrisome if the “baffles” are “leaky”.
- Non-sealing “baffles” may result in CO<sub>2</sub> injected into two sand units joining together and allowing for additional vertical migration of the plume.
- The presence of “baffles” in the Lower Tuscaloosa ‘Massive’ Sandstone is expected to result in a plume of less than half of the areal extent if the ‘Massive’ Sandstone were a homogeneous reservoir at the Mississippi Test Site.