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Composite confining systems: Characterizing, de-risking and permitting unconventional seals for CO_2 Storage

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Abstract

Permitting, developing and operating a CO_2 storage site depend on demonstration and ongoing verification of secure containment. Injected CO_2 and displaced brines must remain confined within a specified storage complex lest they endanger shallower fresh-water aquifers or leak to surface. Here we revise, update and organize the concept of “composite confining system” as the key element that can provide this confinement.

A composite confining system is a multi-layered rock unit in which the net effect of the layering is to retard vertical fluid migration so that fluids injected below it do not migrate above it. We show that effect of multiple layers of contrasting capillary entry pressure creates highly anatomizing flow paths along which capillary trapping as residual phase CO_2 and dissolution in brine effectively traps CO_2. The same long flow paths attenuate pressure increase, limiting brine migration. The composite confining system has a calculatable retention capacity; if CO_2 accumulation or pressure increase exceeds the capacity, CO_2 or brine will migrate through the composite confining system and leak at the top.

The composite confining system concept is proposed in contrast to the concept a reservoir seal providing containment. A seal is required to 1) have low capillary entry pressure and 2) be continuous over the storage complex. Flaws in the seal are of concern because they provide leakage pathways, this might include stratigraphic or structural discontinuities. The value of a seal is that can retain a significant column of hydrocarbons such that an economically producible mobile column is produced. Regionally extensive marine shales, tight carbonates and evaporites are traditional reservoir seals and historical experience with hydrocarbon exploration and production has proven the capability of geologic seals to retain buoyant fluids on multi-million-year timescales. The same properties also make these formations attractive as confinement for CO_2 storage and indeed, many of the projects permitted to date rely on one or more such seals.

However, there are many highly attractive geologic reservoirs that do not have an easily-characterized overlying regional seal. One such area is the onshore region south of Perth, the site of the proposed South West Hub storage project. Another is the Mississippi River Chemical Corridor in south-eastern Louisiana. Both of these areas have excellent reservoirs and significant local emission sources but lack continuous mappable seal units.

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We used a three-pronged effort to quantify and predict the confinement capacity of this system. In the first part, we look at the local geology and use extensive well logs, local hydrocarbon field data and analogue data to create a statistical description of the permeability variations. In the second part, we use physical analogue modelling to investigate the effects of bed-scale permeability variation on the flow and retention of injected CO_2. These models serve to inform our view of which variables matter and to calibrate full-physics reservoir modelling, which forms the third part of our work. In this last part, we use thin, fast-running models to experiment with the effect of varying petrophysical parameters on the migration pathway and local trapping of fluids at the field-scale.

Keywords: storage; confinement, seal, confining zone, containment; composite confining system

1. Introduction

Because CO_2 is buoyant at reservoir depths, a barrier to upward migration is essential to retaining CO_2 at depth and preventing escape to the atmosphere. Confidence in retention has been based on analogy with reservoir top seals beneath which similar buoyant fluids have been retained over geologic time to form oil and gas reservoirs. However, geologic storage as part of CCS project is actually less demanding than petroleum resource accumulation because the injected CO_2 does not need to be concentrated or remain mobile and recoverable. In fact, storage is more secure if the CO_2 mobility decreases during storage, reflecting a different the different goal of sequestration, in contrast to production. Furthermore, inject of CO_2 is planned for industrial quantities on decadal timescale in contrast to hydrocarbons, which are produced in geologic volumes over millions of years.

These reduced demands raise the question "What do we actually need to assure confinement?" In the US , the EPA Class VI Regulations are not prescriptive as to the characteristics of a confining zone, any feature that provides retention can be proposed (UIC Class VI, 2010). Optimizing the definition of confinement could unlock new acreage for storage and in fact offer greater security for permanent sequestration.

2. Novel concept – Composite confining system

A hydrocarbon-type seal in contrast must be continuous over the area of the CO_2 plume and elevated pressure known as the Area of Review (AoR) and have sufficiently low capillary entry pressure so that CO_2 cannot migrate though the seal. Mappable regional shale, evaporite and carbonate layers are candidates for assessment of continuity and capillary entry pressure to qualify as seals to prevent vertical fluid migration of either CO_2 or brine at elevated pressure.

Here we propose and test a novel concept to meet the requirement of preventing vertical migration of CO_2 out of the storage complex. A composite confining system is has the following properties:

- Multi-layered system of barriers that can be laterally discontinuous
- No a priori requirements for continuity or capillary entry pressure
- In aggregate, the system creates a long, tortuous path for vertical flow that spreads migrating CO_2 horizontally, reduces the driving force (column height) and attenuates the mobile fraction
- Imagine 10s of barriers over 100s of meters of section
- Average barriers length may be km-scale
- This is the only confining zone needed, no hydrocarbon type seal is needed.

The composite confining system sufficiently retards vertical migration so that vertical fluid migration of either CO_2 or brine at elevated pressure enters the bottom of confining system, but does not exit the top. The composite confining system has a capacity in that if either CO_2 column high or duration of elevated pressure in brine exceed the capacity, the retardation function will be exceeded and fluid will escape. Therefore, matching the confining properties of the composite system to the planned injection scenario is needed. In this study we assess the input variables that control confining capacity, including properties of the fine-grained layers in the composite, the length of fine-grained layers in composite, and number of fine-grained layers.

The power of composites in retention has been recognized broadly in previous work, for example as aquitards in groundwater flow systems and waste zones or migration loss in petroleum reservoirs. A number of storage projects proposed for CCS have proposed composites, and referred to them as systems with secondary and tertiary barriers (Holloway, 1996; Lindeberg, 1997; Oldenburg and Unger, 2003; Oldenburg, 2008; Nordbotten et al., 2009; Green and Ennis-King, 2010; Sharma and Van Gent, 2018*)*. Composite confining systems are analogous to Reason's 'Swiss cheese model' which has been applied to Covid containment, accident prevention, cyber security and even modern warfare (Reason, 2000; Shappell and Wiegmann, 2000; Roberts, 2020; Tanimoto et al., 2020; Spencer and Collins, 2022).

3. Study design

Our study is designed to answer the following questions:

- A composite confining system is defined as a multi-layered system of barriers that can be laterally discontinuous. What constitutes a barrier in this system?
- How many barriers would we encounter per 100m of section?
- What is their length and geometry?
- How much CO_2 could they contain?
- How do we de-risk the performance of this confining system?

Our approach combines three ways of looking at the problem. We use geologic characterization of the Miocene age strata of the Gulf Coast to evaluate what they can tell us about the storage performance and properties of this interval that contains no mappable marine shales but does retain hydrocarbons. We augment this with detailed multi-phase fluid modelling of a mapped Miocene interval. To evaluate the mechanisms composite confinement, we designed a "sand box" experiment that allows us to experiment with when/where/how the system fails.

4. Three assessments of composite confining systems

4.1. Performance of petroleum systems as indicators of effectiveness of composite confining systems

The Miocene strata of southern Louisiana offers a useful example to probe the geologic character of a potential composite confining system. Within the depth window for CO_2 storage, the geology is dominated by sand-rich deltaic and shore zone deposits with large numbers of interbedded mudstones but few regionally mapped shale-rich seals (Snedden and Galloway, 2019; Bump et al., 2021). Figure 1 shows the pinch out of mappable marine shales (gray) into a stack of sandstones, muddy sandstones and shales that are difficult to correlate long distances.

Extensive oil and gas production illuminates the quality of reservoirs and creates a rich subsurface dataset. we used published historical reservoir descriptions of 67 reservoirs in 61 fields, plus more than 330 SP logs that we calibrated to GBDS biostratigraphy and depositional environment (Figure 2; McCampbell et al., 1964; Collier, 1965, 1967; Harrison et al., 1970; McCormick, 1983; Anderson et al., 1989; Christina and Corona, 2010). Figure 3 shows geostatisics regarding the minimum length of hydrocarbon reservoir seals. We could assume that the fine-grained layers extend an unknown extent beyond the mostly structurally defined traps. Figure 4 shows the thickness and vertical frequency of fine grained zones mapped on their log signature; these data are used to constrain fluid flow models.

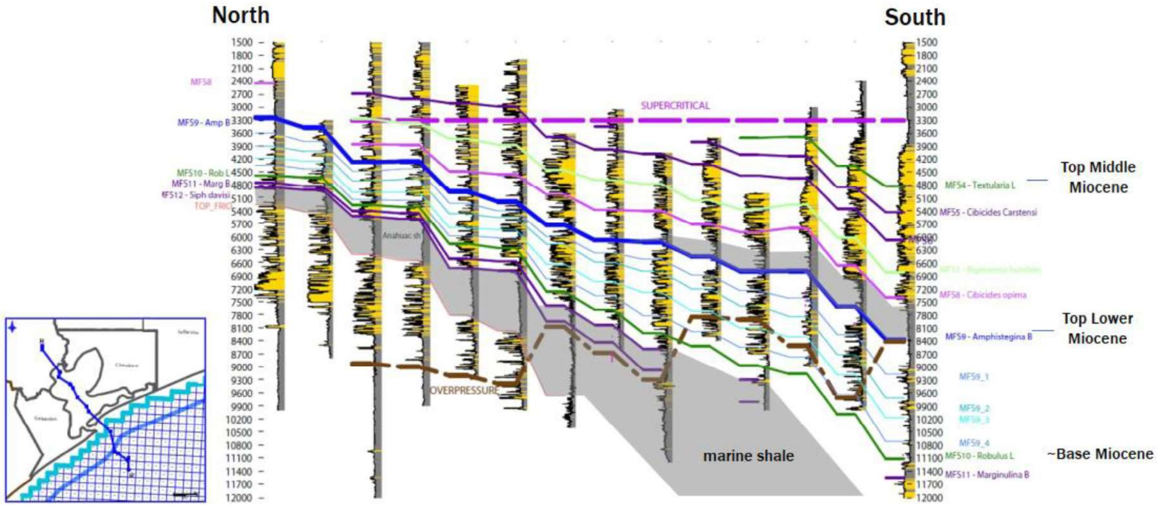

Figure 1: Typical Miocene stratigraphy from the upper Gulf Coast. Note the mappable marine shale in the base of the middle Miocene thins and transitions to less continuous interbedded sandstones and fine-grained units, however hydrocarbon accumulates over the entire area.

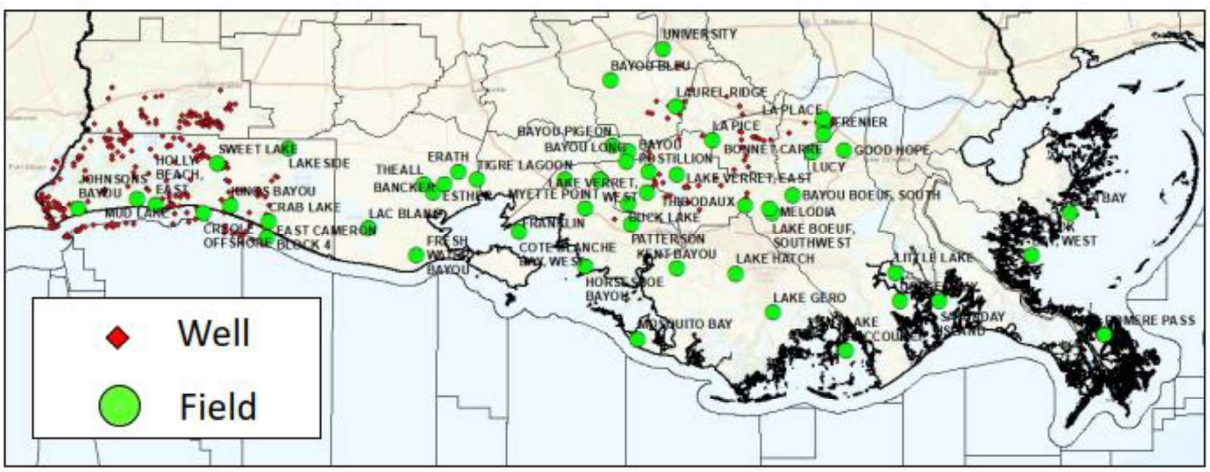

Figure 2: Field and well inventories to develop statistics on barrier length, thickness and frequency.

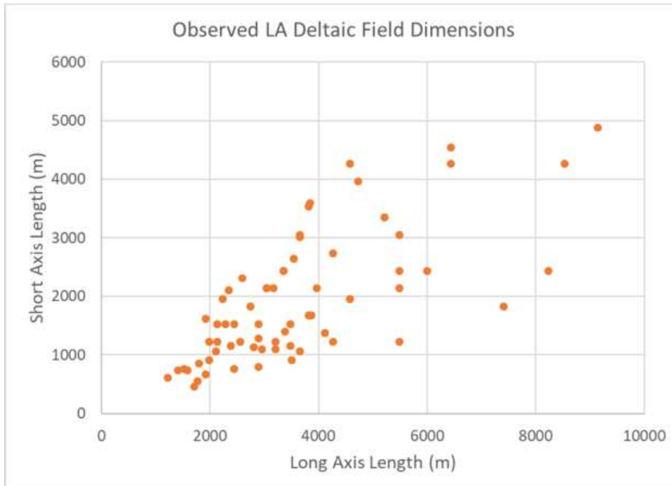

Figure 3: Observed Louisiana field dimensions from literature review. This data provides a minimum length of seals in the Miocene section and is used for modelling.

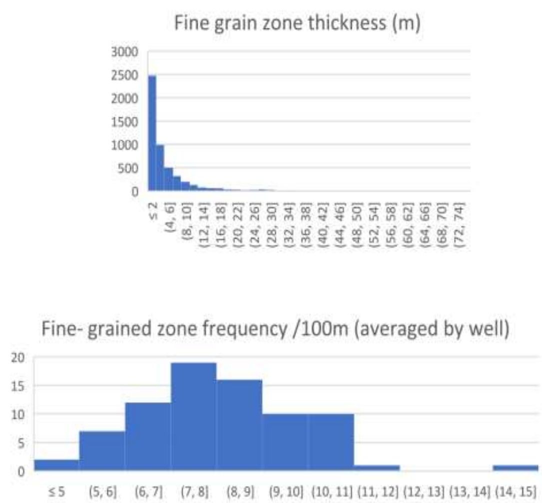

Figure 4: Examples of measured thickness of fine-grained zones and number of fine-grained beds per 100 meters of section measured in wireline logs.

4.2. Reservoir modeling

A 3D geomodel of the Louisiana coastal Miocene section based on a static model located on the flank of an anticline with a ~2º dip was used to test the performance of the Miocene in retaining CO_2. The model measures 9.6km x 10.5km x 0.9km. The model is composed of a 174m-thick injection zone, overlain by a confining zone with a thickness of 686m. The injection interval is composed of coarse sand and the confining zone is populated with the same coarse sand, interbedded with discontinuous siltstones and mudstones (figure 5). The capillary entry pressure values for the coarse sandstone, siltstone, and shale are considered to be 0.2, 1.5, and 1488 psi, respectively based on grain-sizes and published correlations (Beckham et al., 2018). CO_2 and brine relative permeability and drainage capillary pressure curves were generated using a Brooks-Corey model.

Numerical injection simulations were conducted using GEM (https://www.cmgl.ca/gem) and Darcy flow, considering pure CO_2 and brine. All boundaries are taken to be closed and initial pore pressure is set to hydrostatic with the gradient of 10.5MPa/km (0.456 psi/ft). CO_2 was injected downdip for 30 years in the reservoir with an injection rate of 59 mmscf/day (1.2Mt/yr). The simulations were continued for 100 years after the injection stopped. Figure 5 shows the CO_2 plume at the end of injection and post-injection. Despite the lack of a continuous seal or even a continuous barrier, CO_2 makes very little vertical progress into the confining system. Rather it tends to channelize underneath the capillary barriers, including both the silty and muddy facies. CO_2 spreads laterally beneath the barriers, with significant residual trapping that attenuates and ultimately immobilizes the plume (figure 6).

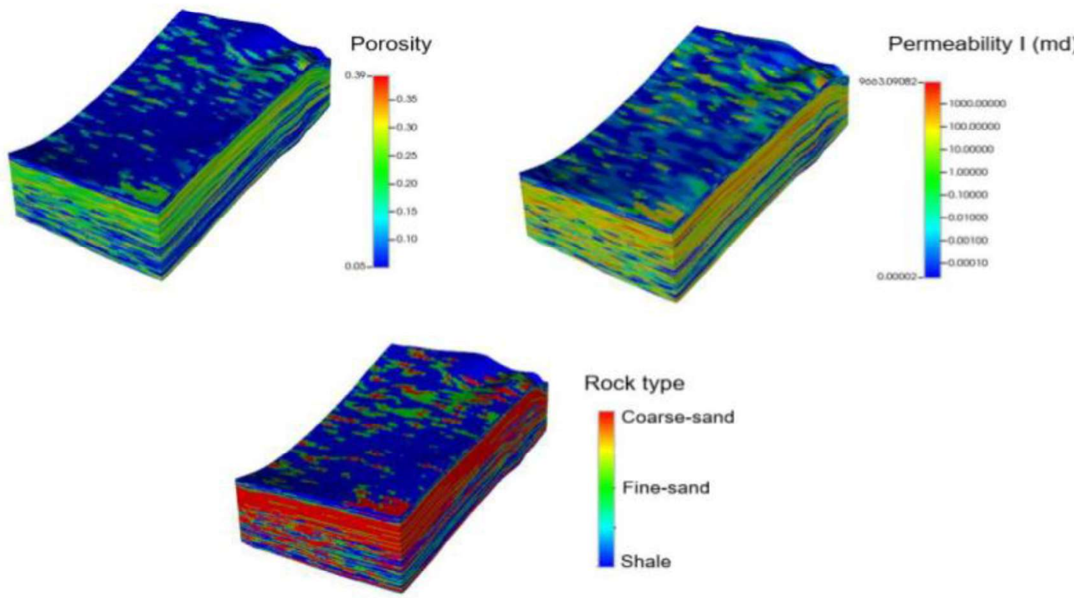

Figure 5: Static geomodel of the lower injection zone and the upper composite confining system. Based on unpublished research by Nunez, Dunlap, and Hossieni.

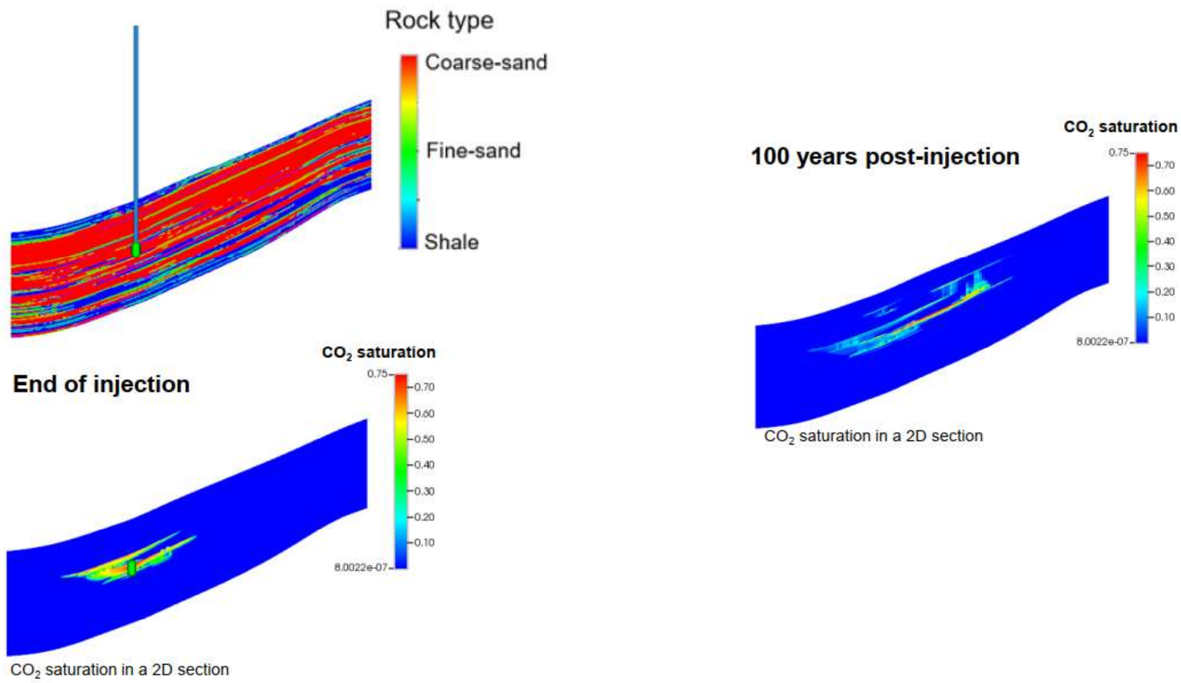

Figure 6: Modelled extent of CO_2 plume at the end of injection and 100 years post-injection. Despite injection into the sandiest interval of the model and despite the lack of a continuous seal or even a continuous barrier, CO_2 makes very little vertical progress into the confining system.

4.3. Bead pack experiments

To investigate the properties of barriers that divert flow within the composite confining system, we conducted physical fluid flow experiments using tank-scale bead packs (Krishnamurthy, 2020). The approximately 1 m across tank was filled glass beads to create three fine-grained barriers of equal length but with variable thickness and variable numbers of subsidiary layers that fine upward (Figure 7). The barriers are all sealed at one end and open at the other. The glass bead grain sizes used for the matrix and the finest (topmost) barriers have mean diameters of 0.689 mm and 0.331 mm, respectively—equivalent to coarse and medium sand (Wentworth, 1922). The system has no shale. The capillary entry pressure contrast between the matrix and the finest (topmost) barrier layer is 0.5, which translates to a k_v/k_h ratio of about 0.2.

Fluid flow experiments were conducted at atmosphere temperature and pressure, using an analogue fluid pair that has been calibrated to replicate the behaviour of supercritical CO_2 and brine properties at typical subsurface storage reservoir conditions (Krishnamurthy, 2020; Ni and Meckel, 2021). Heptane represents supercritical CO_2 (the nonwetting phase) and a glycerol-water mixture represents brine (the wetting phase). We initiated the experiment by injecting heptane through the center bottom inlet at a low flow rate (0.2 mL/min) so that the flow regime is buoyancy-dominated. Heptane was allowed to rise through the tank under buoyancy forces until it exited the top of the tank, concluding the drainage experiment. For the duration of the experiment, we used a high-resolution, monochrome camera to capture time-lapse images of the back-lit flow cell (Krishnamurthy et al., 2019; Krishnamurthy, 2020; Ni and Meckel, 2021).

Figure 7 is an image taken at the end of the experiment, showing the residual saturation and the flow path of the non-wetting fluid. There are several significant insights that emerge. First, even flat barriers retain buoyant fluid beneath them. Self-evidently, the amount of fluid retained would increase in proportion to the number and length of the barriers. Capillary entry pressure need only be enough to divert flow. Even changes from medium to fine sand can create a barrier. This experiment reinforce es the previous findings that discontinuous barriers each trap some CO_2. We can scale the outcomes to show that barrier length and frequency define the confining capacity of the composite system. in further experiments we show that favorable barrier topography helps

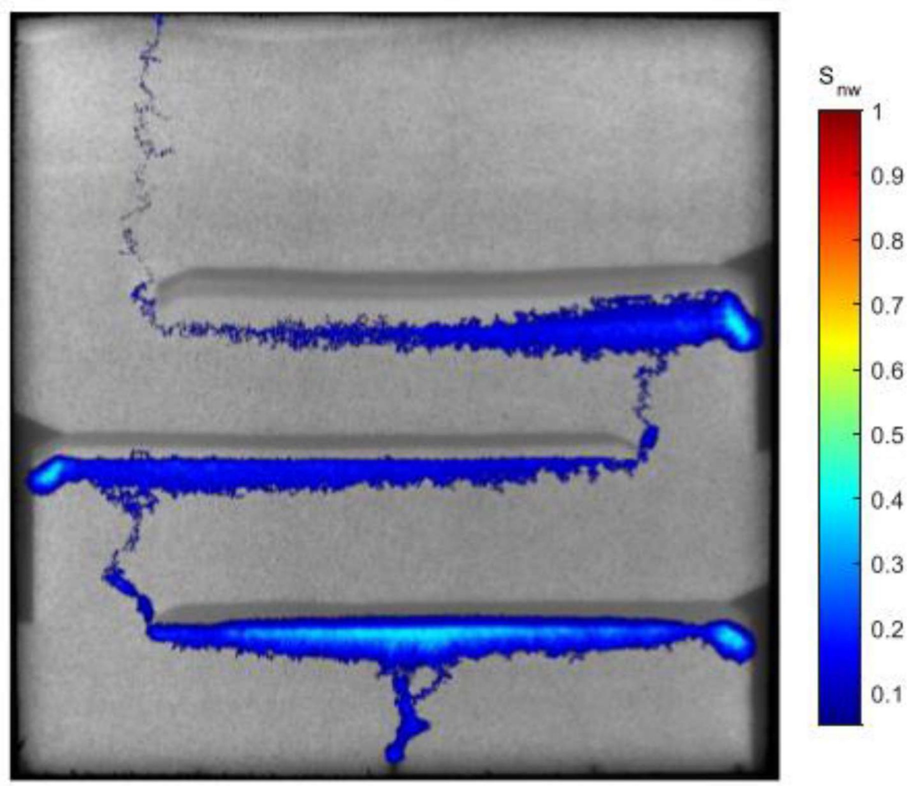

Figure 7: Image of the bead pack at the end of the drainage experiment at domain percolation; the nonwetting phase plume is shown in blue (different shades denote saturation, as shown in the scale bar).

5. Conclusions and next steps

From the three types of information assessed in this study performance of composite confining systems in retaining hydrocarbons, modeling fluid flow though realistic representation of the confining system, and bead pack experiments – we show that composite confining systems are effective in retaining buoyant fluids. Storage security is enhanced because migration of some of the CO_2 into the base of the confining system where it is trapped results in decrease in the mobile fraction below the confining system and small column heights.

- Composite confining systems are fundamentally different from regional seals because:
- Expect fluids to invade the base of the zone
- We care less about details of individual barriers than aggregate performance of the system

- the retention capacity is an associated new concept assessing how much can be injected before you saturate the system.

In next steps we will explore retention capacity: How do we make these systems fail? this was accomplished for the bead pack but not for the fluid flow model. Adding features that build greater column higher would be needed to drive CO_2 through the composite confining system. Further, we plan to increase characterization and monitoring tools to further de-risk composite systems

Acknowledgements

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