Water Interactions with Shales, and Impacts on Gas Mobilization

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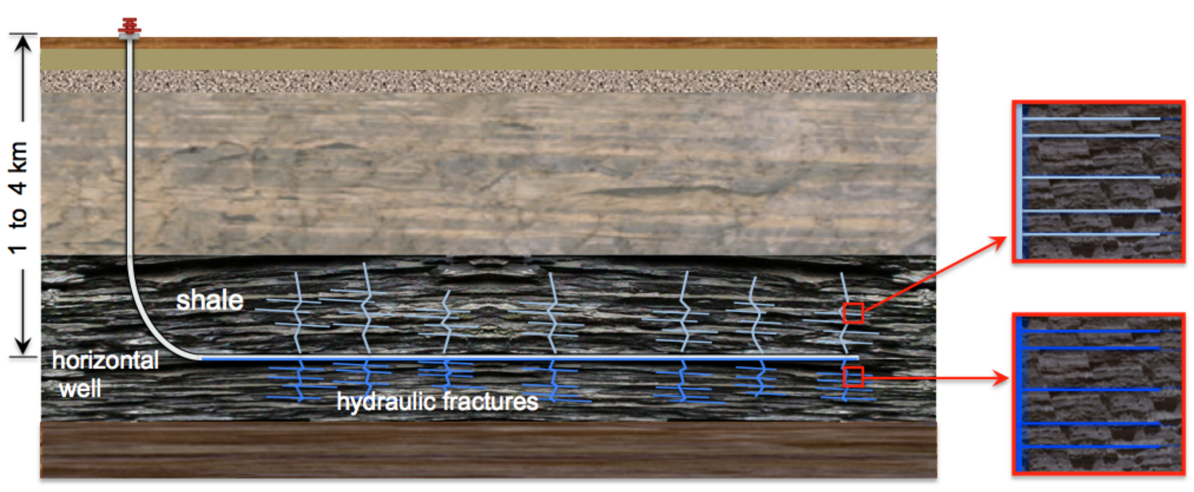
ABSTRACT

The use of water-based hydraulic fracturing fluids in stimulation of unconventional reservoirs is problematic because of formation damage from water blocking, and because of costs associated with use of large volumes of water are required treatment of flowback water. This research is aimed at understanding of how water interferes with the desired counter-flow of gas from shale into fractures, and also is exploring approaches for significantly reducing water use in fracturing. Most of our experiments have been conducted on Woodford Shales, which were found to exhibit strongly hysteretic water uptake and drainage. Very high capillary retention (water blocking). The measured diffusion-limited approaches to equilibrium are being modeled. Influences of gravity on draining of injected water from hydraulic fractures and enhancing gas production are being explored through simulations of fracture-shale matrix interactions. A novel natural biosurfactant is being developed for supercritical fluid foams for reducing water use in fracturing.



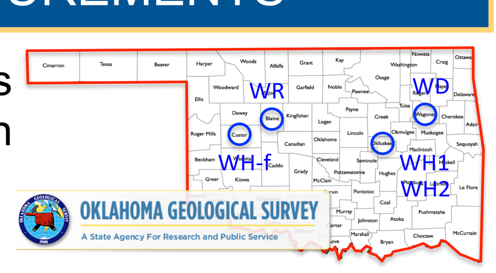
Water-based hydraulic fracturing fluids occupy shale pores along newly generated fractures, block flow of gas to wells.

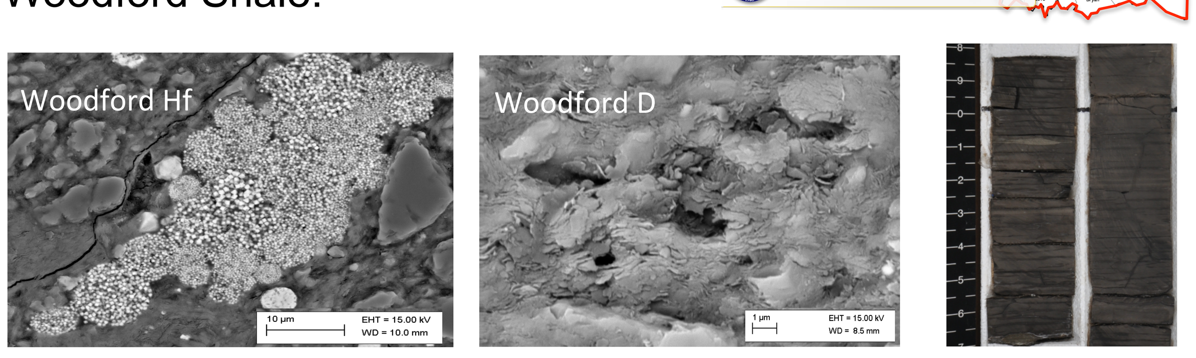
OBJECTIVES

- Understand coupling between water imbibition and gas counterflow in shales in order to help identify approaches to improving production.
- Understand the effectiveness of low-water fracturing fluids on shale gas/oil mobilization, and improve performance of fracturing fluids.

SHALE SAMPLES AND MEASUREMENTS

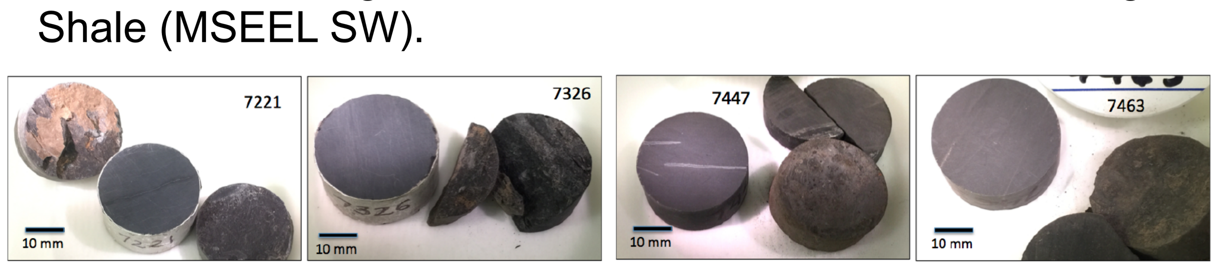
Most of our laboratory measurements on gas shales have been obtained on samples from wells in the Devonian Woodford Shale.



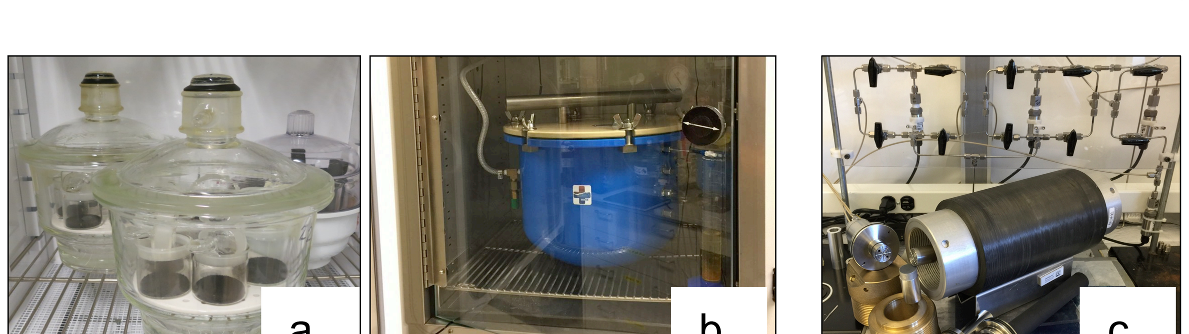


LBNL label	Operator	Well	Sample depth	county	Total Carbon	Inorganic Carbon	Organic Carbon	bulk density	grain density	porosity
			m		mass %	mass %	mass %	g/cm3	g/cm3	
WHf	GHK	Hoffman	4346.3 - 4347.2	Custer, OK	4.29	0.40	3.89	2.58	2.76	0.065
WR	Pan American	Roetzal	2569.0 - 2569.9	Blaine, OK	7.11	0.00	7.11	2.41	2.62	0.081
WD	Res Dev Tech	Dunkin	282.3 - 283.1	Wagoner, OK	6.07	0.46	5.61	2.41	2.59	0.070
WH1	Star Resources	Holt	1126.7 - 1127.6	Okfuskee, OK	6.29	3.61	2.68	2.42	2.69	0.100
WH2	Star Resources	Holt	1128.5 - 1129.4	Okfuskee, OK	5.54	0.00	5.54	2.50	2.68	0.067

We have also begun studies on Marcellus and Mahantango Shale (MSEEL SW).



SW depth		Sample ID	Complete ID	Formation
ft	m			
7221	2201.0	126-7221	4-126-M22-7221	Mahantango Shale
7271	2216.2	122-7271	4-122-M18-7271	Mahantango Shale
7326	2233.0	118-7326	4-118-M14-7326	Mahantango Shale
7391	2252.8	112-7391	4-112-M8-7391	Mahantango Shale
7426	2263.4	89-7426	3-89-M23-7426	Marcellus Shale
7430	2264.7	85-7430	3-85-M19-7430	Marcellus Shale
7444	2268.9	73-7444	3-73-M7-7444	Marcellus Shale
7447	2269.8	70-7447	3-70-M4-7447	Marcellus Shale
7463	2274.7	51-7463	2-51-M11-7463	Marcellus Shale
7470	2276.9	43-7470	2-43-M3-7470	Marcellus Shale

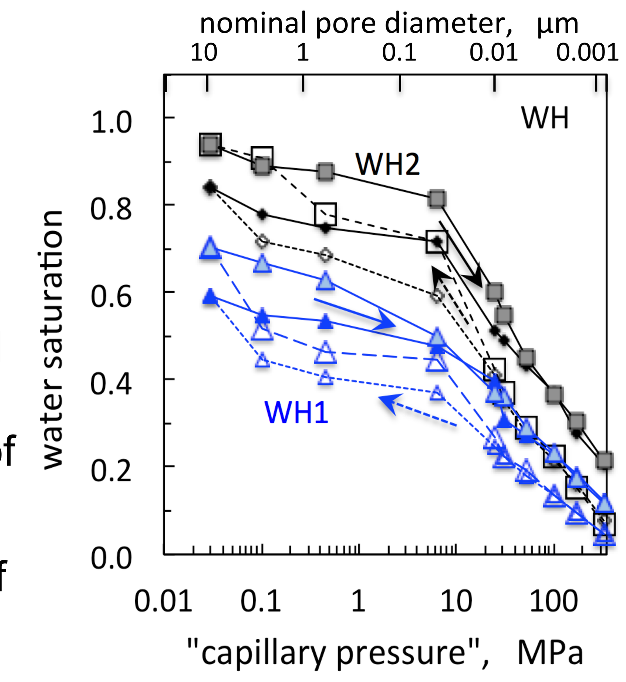


Measuring shale wetting and drainage (a.) fixed relative humidity systems, (b.) pressure plate device, (c.) transient imbibition and gas counter-flow core holder.

STRONG CAPILLARY RETENTION OF WATER IN SHALE

Relation capillary pressure (P_c), and water saturation need to be understood to predict water distribution in shales and pressure differences needed to allow gas flow. We have measured shale water saturation relations over a wide range of water activities and P_c.

- Large capillary hysteresis of water retention.
- Very strong retention of water in most samples.
- Less hydrophilic behavior of calcite-rich shale.

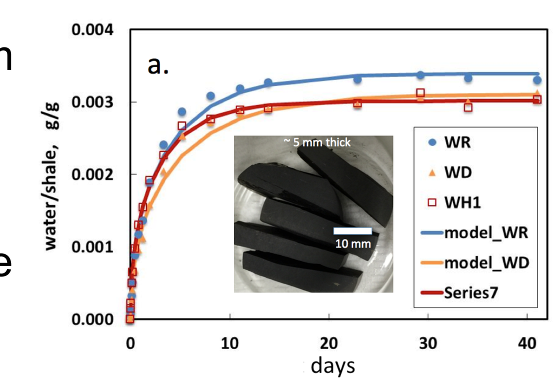


Wetting and draining capillary pressure relations (50 ˚C) for Woodford Shales with 30% calcite (WH1), and negligible calcite (WH2).

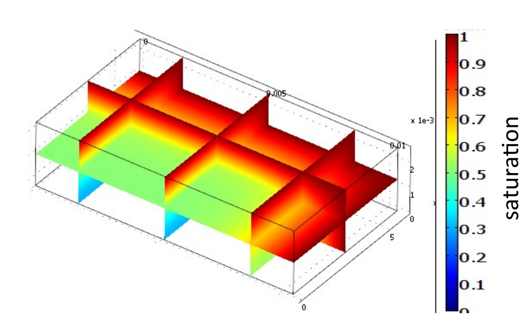
DIFFUSION-LIMITED WATER VAPOR ADSORPTION

Time needed to reach equilibrium in adsorption-desorption, and imbibition-drainage processes is often underestimated, and leads to errors in measured constitutive relations. Our vapor adsorption experiments on ~ 1 cm pieces of shales required weeks to reach equilibrium.

- Effective diffusion coefficients in the range of 9E-9 to 3E-8 m2/s were obtained through modeling of the diffusion process. These values are consistent with other measurements on low-porosity rocks.
- Experiments and simulations of diffusion in anisotropic shale are underway.



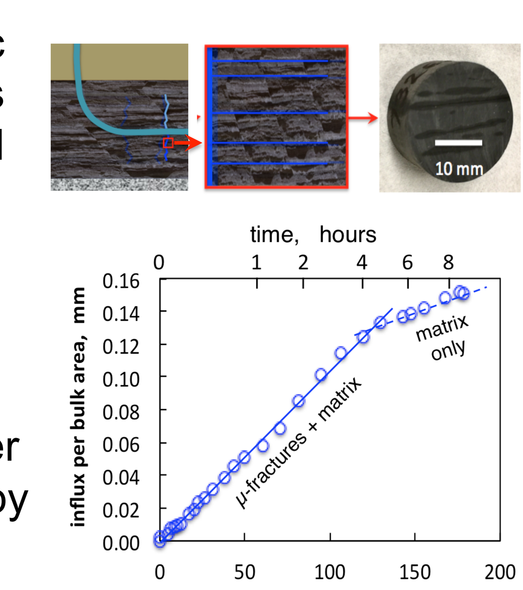
Time-dependence of water uptake in Woodford Shales, 50 ˚C, 32% relative humidity.



Modeled saturation distribution at 1 day of vapor diffusion into initially dry shale lamina (quarter of the domain shown).

INFLUENCES OF WATER IMBIBITION THROUGH MICROFRACTURE NETWORKS

- Predominantly vertical hydraulic fractures supply fracturing fluids to primarily horizontally oriented microfractures in shales.
- Initial imbibition enhanced via flow in microfractures (natural and stimulated).
- Imbibition into shale over shorter and longer times is dominated by microfracture and matrix imbibition, respectively.

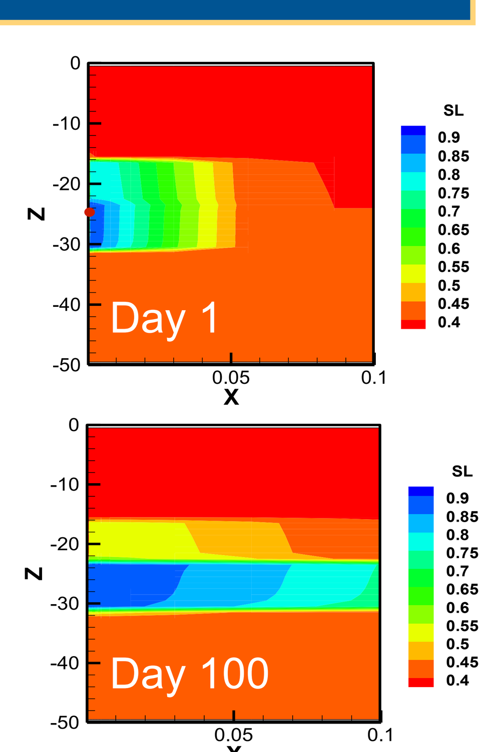


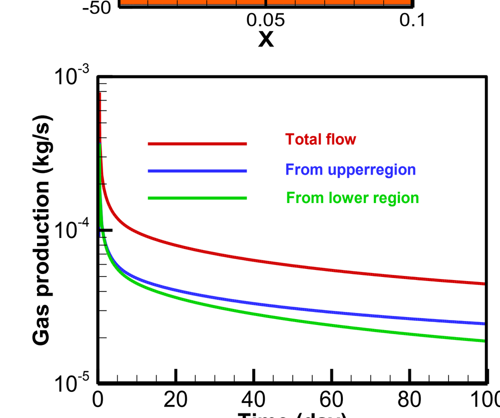
INFLUENCES OF GRAVITY DRAINAGE OF WATER IN FRACTURES ON GAS FLOW

Given the large fractions of hydraulic fracturing fluid remaining in reservoirs long after injection, and the measured strong capillary retention of water in shale, why are wells commonly so productive?

Gravity drainage of hydraulic fractures above horizontal wells is very effective, leaving little water to imbibe into shale in the upper portion of reservoirs, thereby allowing efficient gas production shales.

The importance of fracture drainage is being investigated through modeling studies of shale fracture-matrix systems. Preliminary results are showing how vertically stratified water distributions affect the distribution of gas flow into wells.

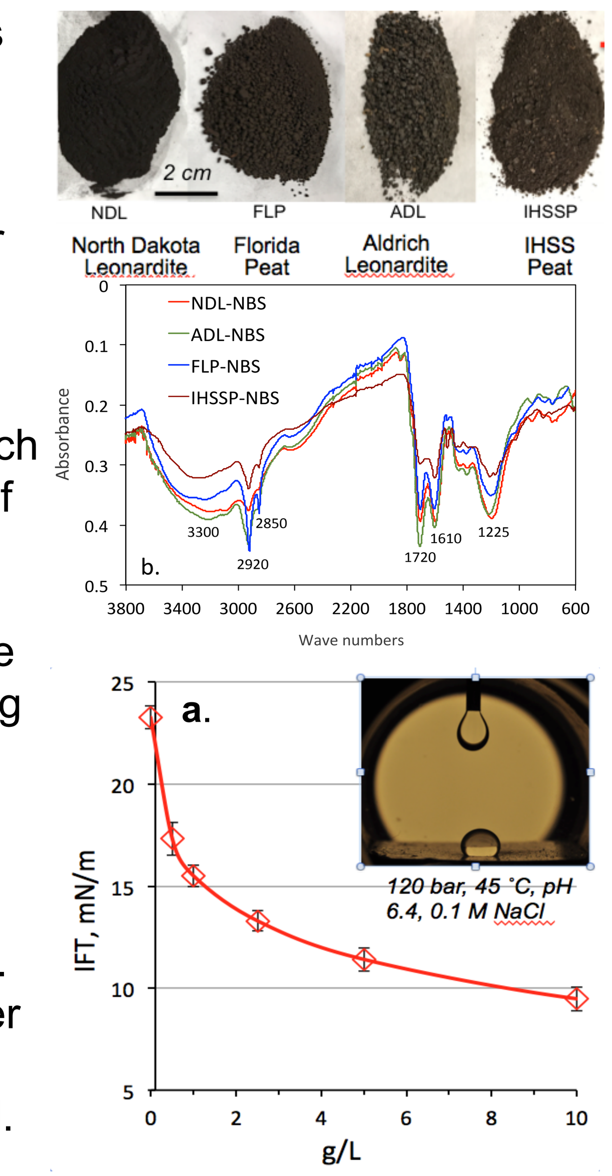


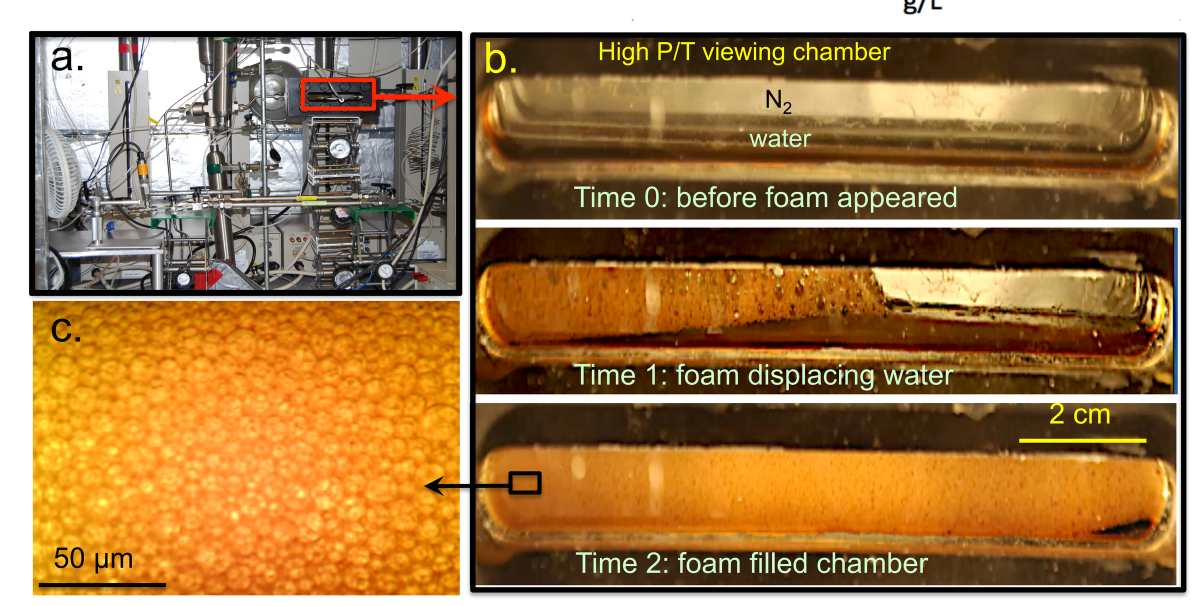


HIGH PRESSURE CO_2 - WATER FOAM DEVELOPMENT

Given the detrimental impacts of injecting large volumes of water into unconventional reservoirs, it is desirable to develop alternative, low-water fracturing fluids. Foams constitute a potentially viable alternative.

- We have identified humic-rich earth deposits as sources of inexpensive natural biosurfactants (NBS).
- A simple, efficient procedure was developed for extracting NBS from raw materials.
- Ability of NBS to effectively lower interfacial tension of supercritical CO2-water systems was demonstrated.
- NBS-stabilized scCO2-water foams with viscosities up to 30 cP have been generated.





$scCO_2$-water foam testing. (a) foam generator, rheometer, and viewing cell (red outline). (b) images of foam entering viewing window. (c) Close-up view of foam with ~10 µm $scCO_2$ bubble sizes.

SUMMARY

- Hysteresis in water imbibition-drainage is important, and very high capillary pressures required to percolate gas through water-blocked shale have been quantified.
- Long times are required to hydraulically equilibrate shales because of their very low permeabilities and low effective diffusion coefficients.
- Gravity drainage of hydraulic fractures above horizontal wells is important in facilitating gas production.
- A supercritical CO2 foam is being tested as a low-water alternative fluid for hydraulic fracturing.

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ACKNOWLEDGMENTS

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