Understanding Water Controls on Shale Gas Mobilization into Fractures

NETL ESD14085

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National Energy Technology Laboratory

Mastering the Subsurface Through Technology Innovation, Partnerships and Collaboration:
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Presentation Outline

- General Background Information
  - Problem statement
  - Goals/Objectives
- Technical Status of current budget period (Oct. 2016 –now, integrating accomplishments, lessons learned, and synergy opportunities within each task)
  - Task 2. Laboratory studies of shale-water interactions
  - Task 4. Modeling studies of shale-water interactions
  - Task 3. Laboratory studies of low-water fracturing fluids
- Summary of key findings
- Next Steps: Activities/tasks to be performed
- Appendix Materials

Problem Statement

- > 10^6 gallons water/well is typically used to hydraulically fracture shale gas reservoirs.
- With typically > 70% of injected water (immiscible w. gas) usually remaining in the reservoir, why is gas production commonly high?
- Understanding is needed on how water distributes in shale and affects production, and how to improve gas/oil recovery, including via reducing water.

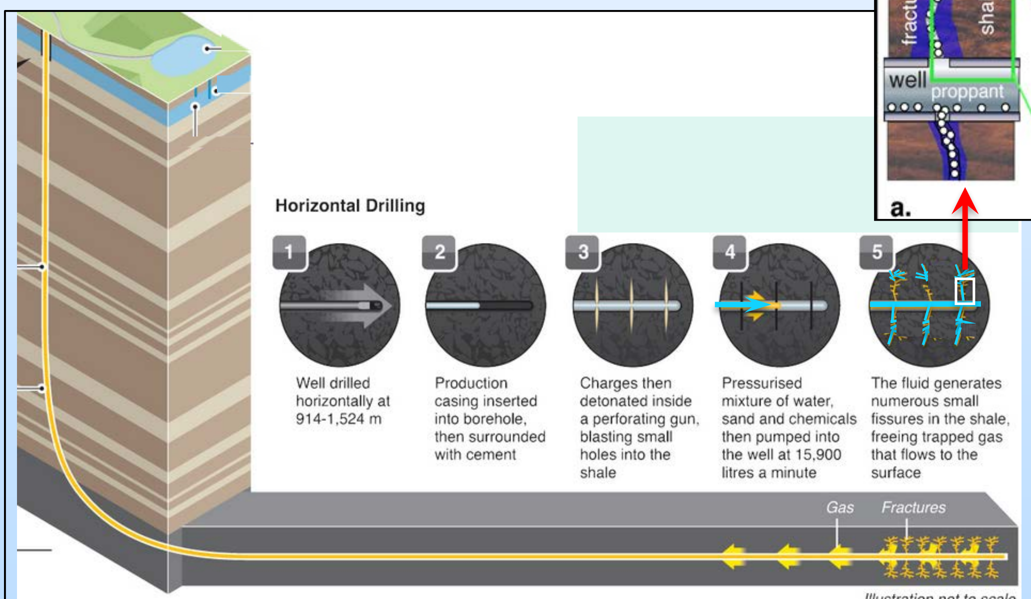
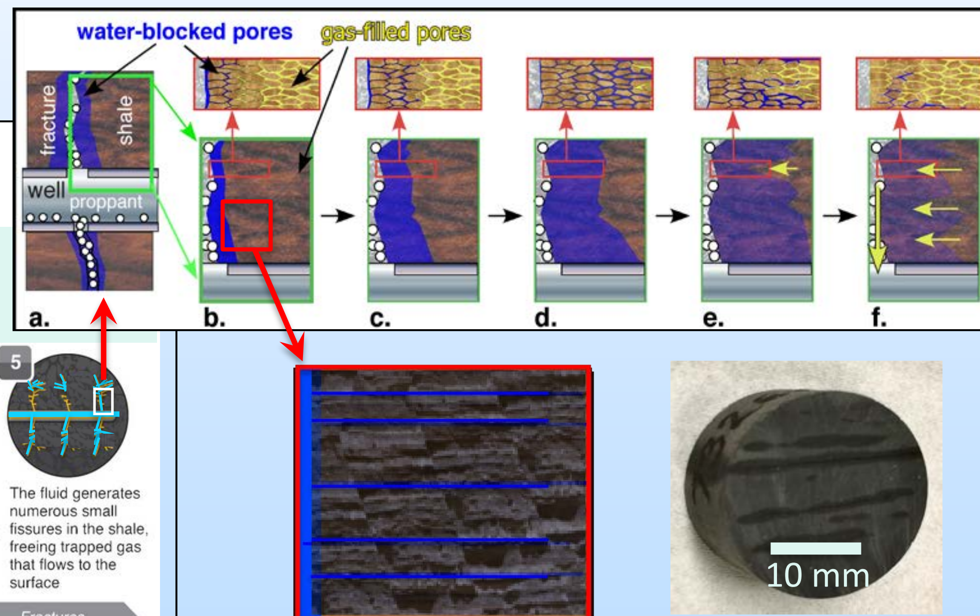


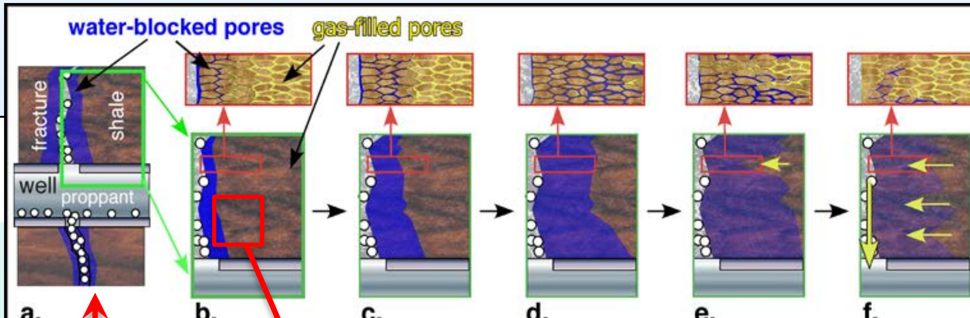
Figure modified from *National Geographic, Chesapeake Energy, EIA, & USGS*



Realistic representations of fluid displacement are needed a basis for developing improved extraction.

Goals and Objectives:

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



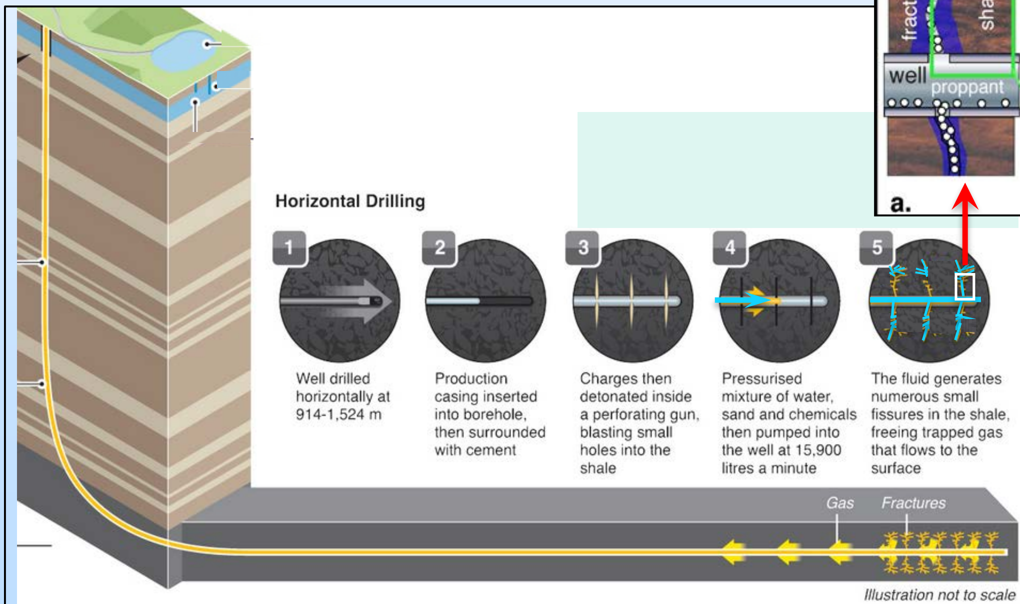


Figure modified from *National Geographic, Chesapeake Energy, EIA, & USGS*

Realistic representations of fluid displacement are needed a basis for developing improved extraction.

Technical Status for Current Period: October 2016 – July 2017

Task 2. Laboratory-based studies of shale-water interactions

2A. Extend shale water saturation relations to near-zero capillary pressure

2B. Measured shale water uptake by vapor diffusion/sorption and by capillary flow.

2C. Modifying core-flooding system for tests of water blocking in shale

Task 4. Modeling studies

4A. Improve/apply constitutive models for shale

4B. Model water and non-water fluids at fracture-matrix interface

Task 3. Laboratory-based studies of alternative fracturing fluids

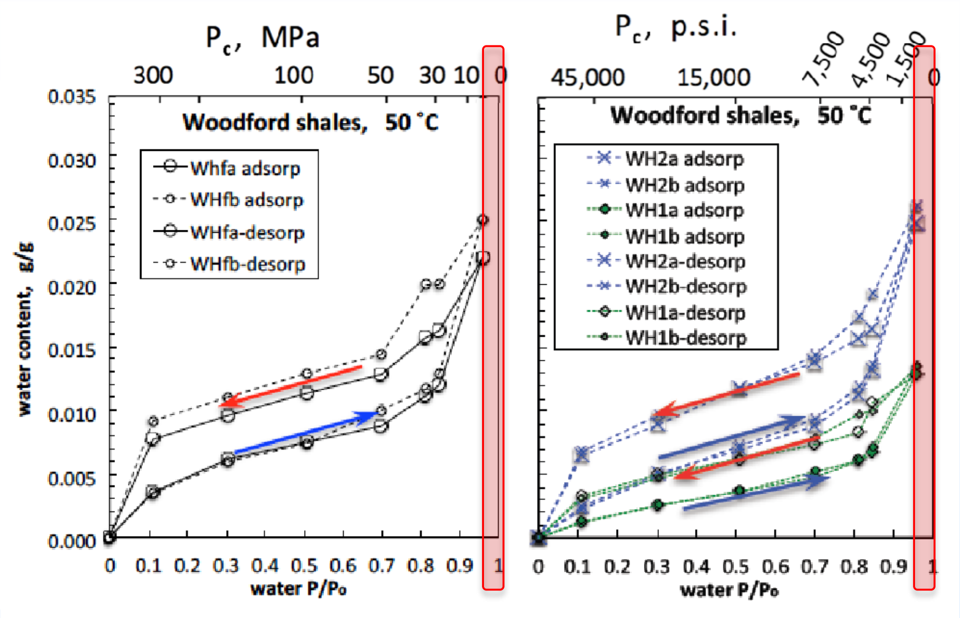
3A. Fracture-matrix micromodel design and construction

3B. New foam generator system testing

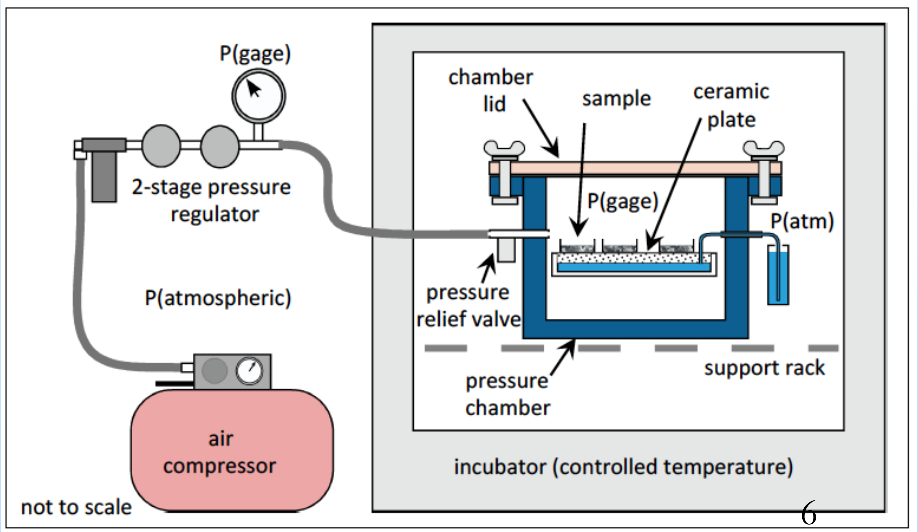
3C. Natural biosurfactant extraction and foam properties measurements

2A. Extend shale water saturation, S_w, relations to near-zero capillary pressure, P_c

- The upper limit for controlling water activity via relative humidity is ~96%, which corresponds to a P_c = 6 MPa (880 p.s.i.).
- Information on shale S_w-P_c relations is needed at much lower P_c to understand flow and transport during hydraulic fracturing, where P_c ~ 0 and even < 0.
- Pressure-plate method was used to obtain measurements closer to zero P_c, at 50 ˚C.

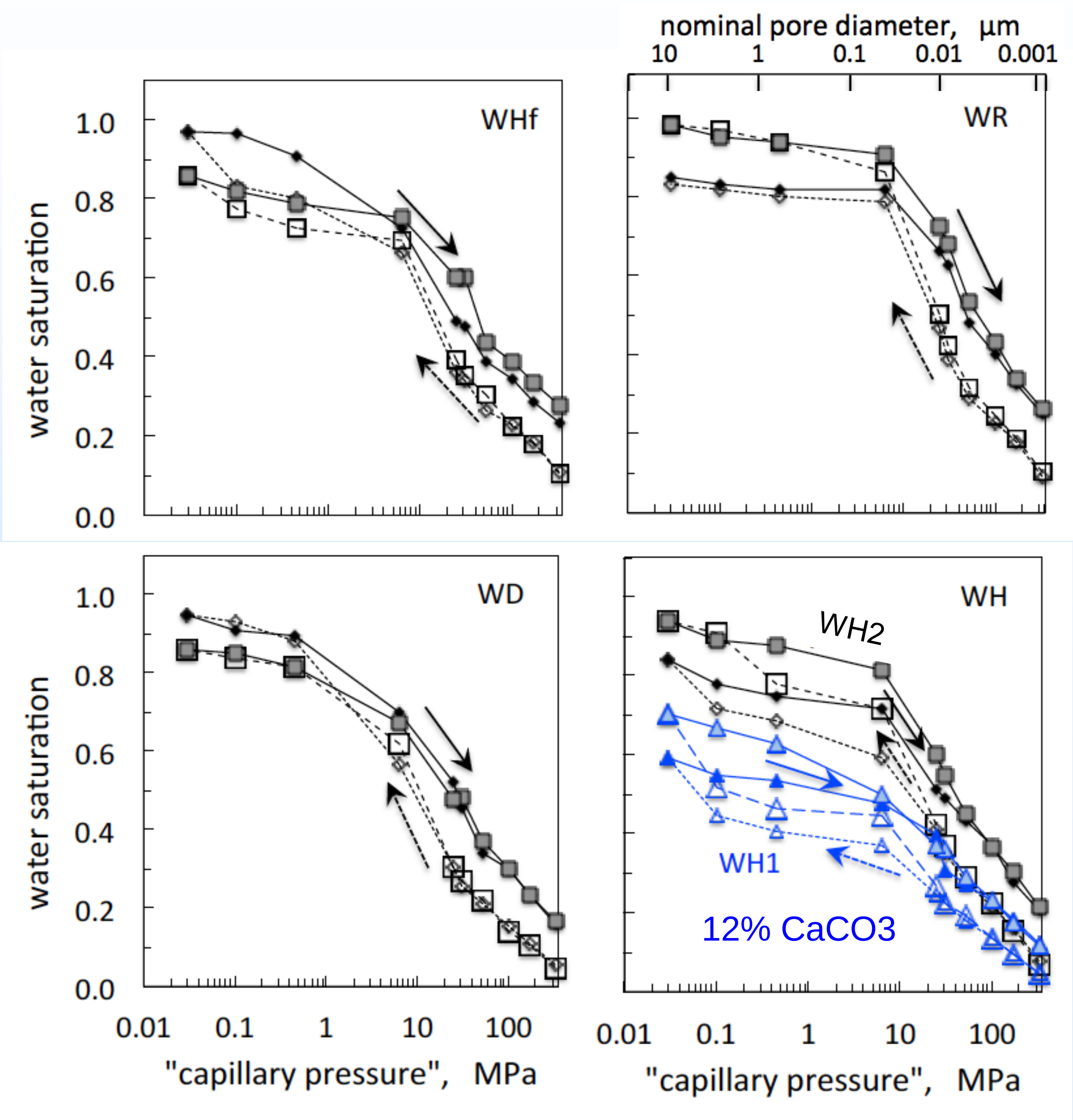


0.5 MPa pressure-plate system in 50 ˚C incubator

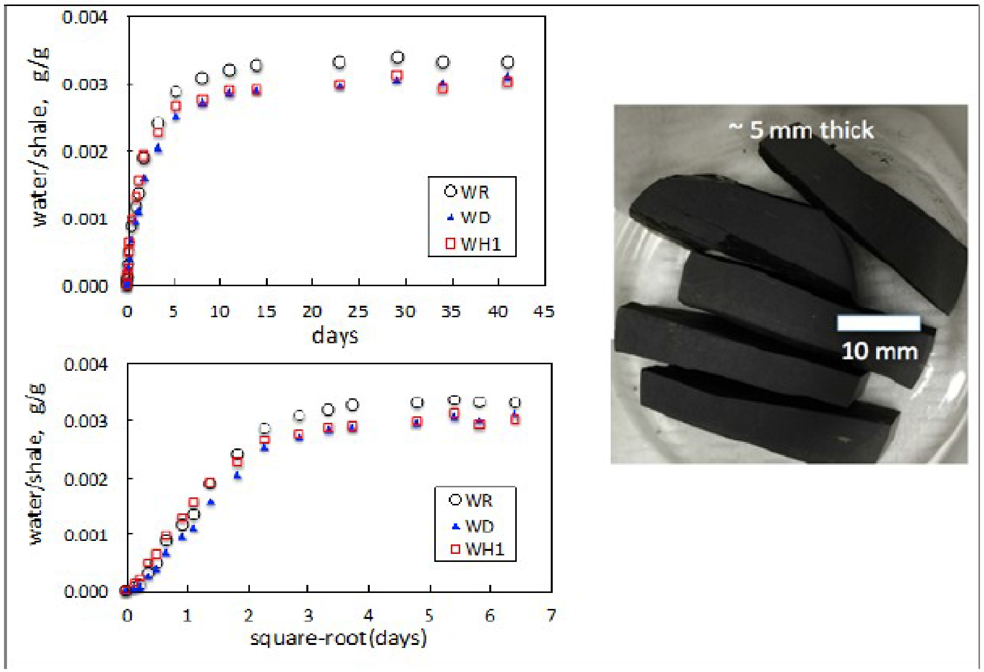


2A. Extend shale water saturation, S_w , relations to near-zero capillary pressure, P_c

- Drainage does not follow the imbibition $S_w(P_c)$ path. **Hysteresis is important**.
- To the best of our knowledge, these are the first complete imbibition-drainage $S_w(P_c)$ relations obtained on shales at "elevated" temperature.
- Once exposed to frac water, **high P_c (e.g., ~1 MPa) is needed to significantly desaturate shale and allow gas counterflow**. Then how do we explain gas production?



2B. Measured diffusion-controlled water vapor sorption into shale blocks.
Transient vapor sorption data useful for determining effective diffusion coefficients (Task 4).



shale	WR	WD	WH1
porosity	0.081	0.070	0.100
L, mm	20.9	23.8	23.5
W, mm	11.8	12.3	13.1
T, mm	5.1	5.2	2.6

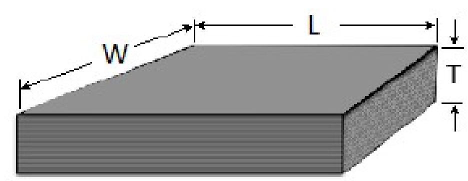
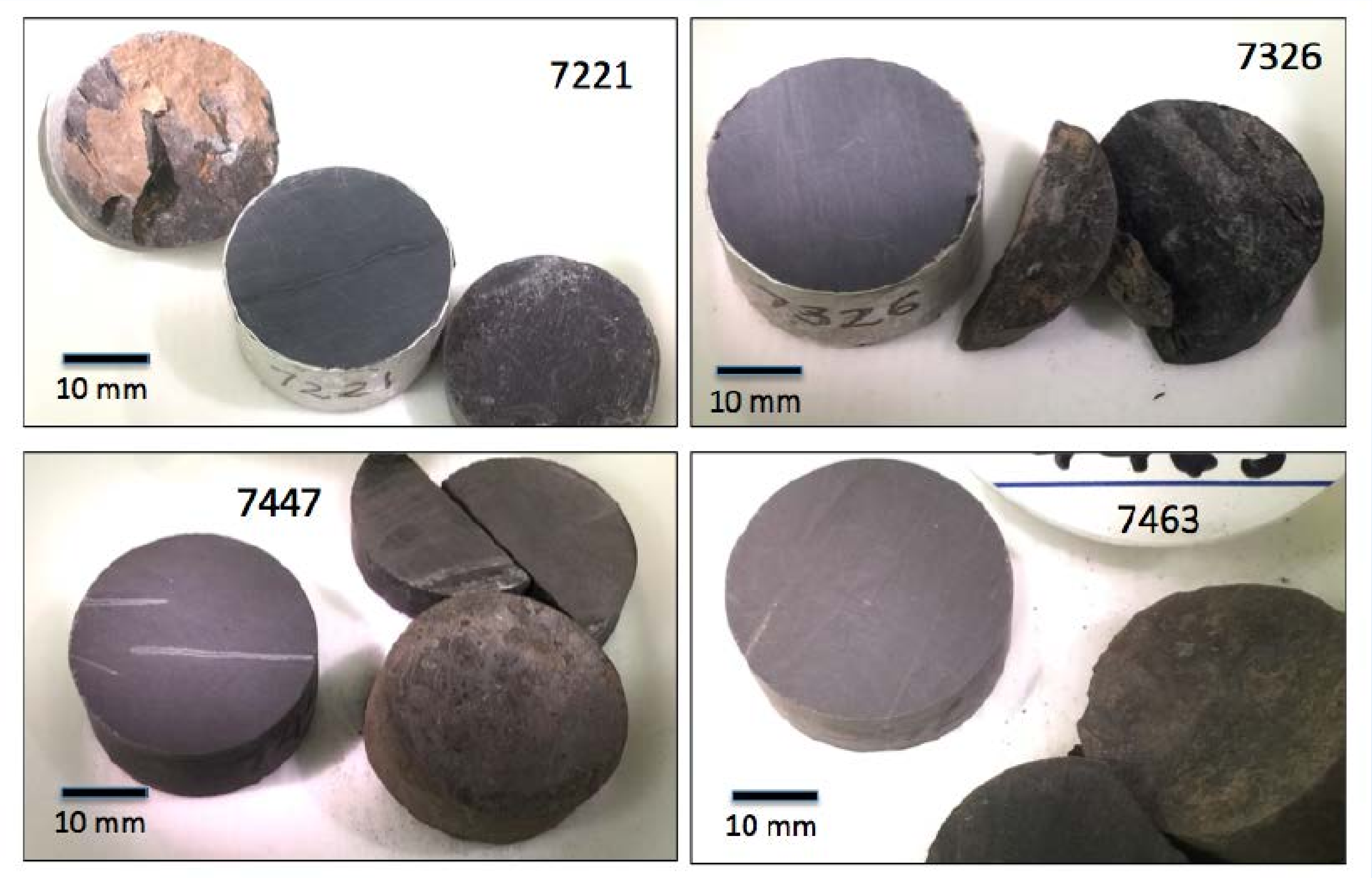


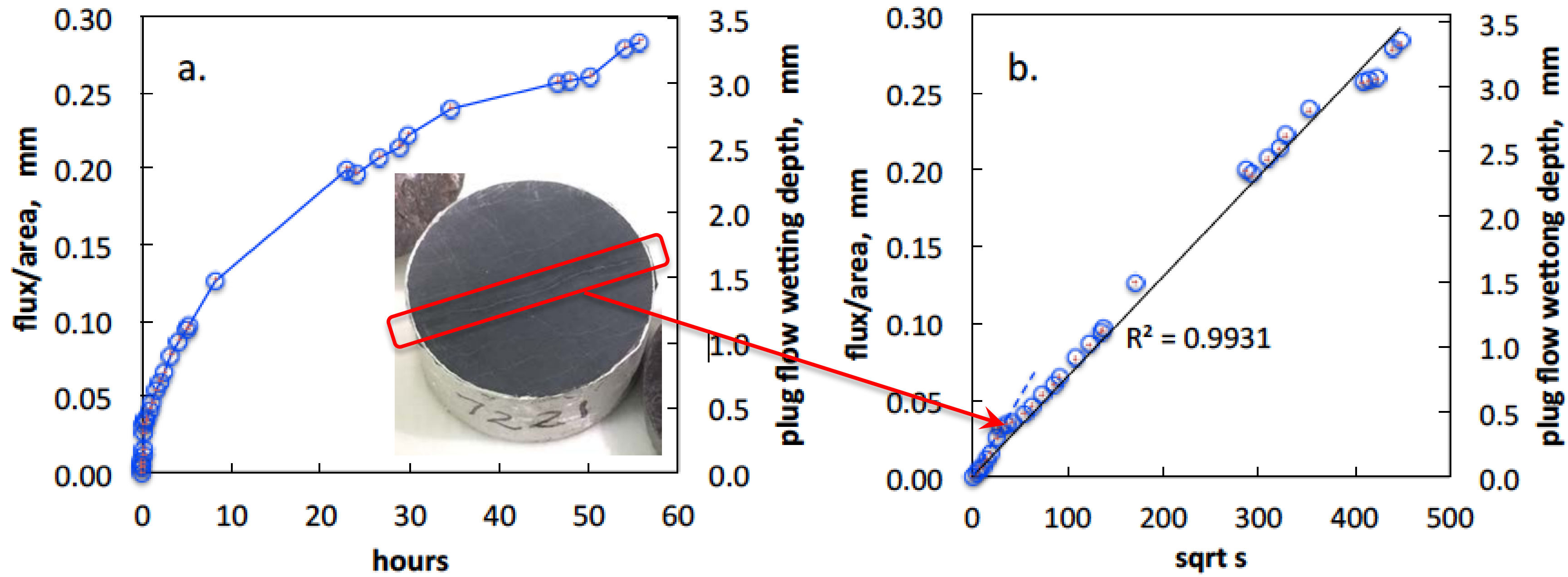
Figure 5. Average equivalent rectangular parallelapiped dimensions of the shale rock blocks and the results of the water molecule uptake experiments through diffusion and adsorption.

- Vapor equilibration of large shale pieces is strongly diffusion-controlled.
- Lack of sufficient equilibration time likely explains some others' reports of insignificant hysteresis in shale water vapor adsorption-desorption relations.

2B. Measured capillary advection-controlled water imbibition into Marcellus shale.
Transient uptake data useful for determining hydraulic properties (Task 4).



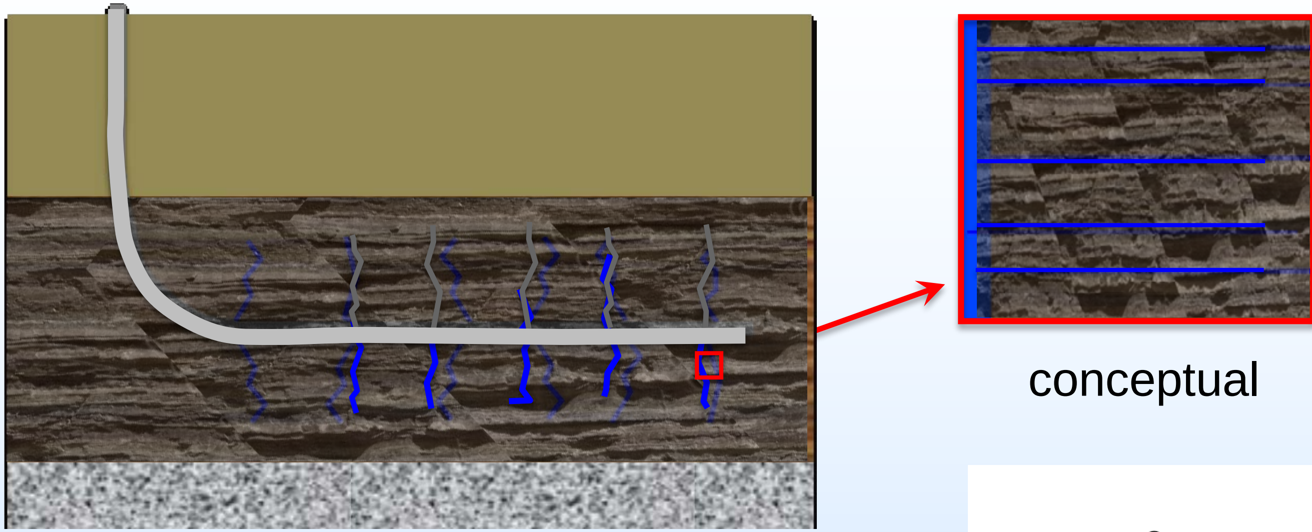
2B. Measuring water imbibition into Marcellus shale. Transient uptake data useful for determining hydraulic properties (Task 4).

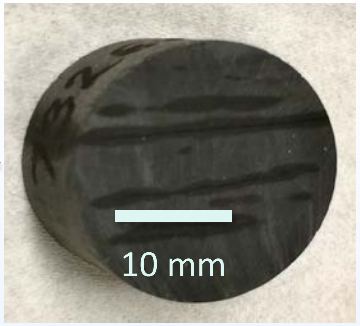


Water (1 M NaCl) imbibition into Marcellus Shale (7221') at 23 ˚C, and atmospheric P. (**a.**) Volumetric influx per unit core area, with through-going microfracture framed in photo. (**b.**) Square-root of time water uptake plot, showing **initial rapid flow into microfracture** (dashed trend line).

Such observations are useful for developing a more realistic conceptual model for water and gas flow in shales.

Evolving conceptual model for water-gas interactions in shale reservoirs

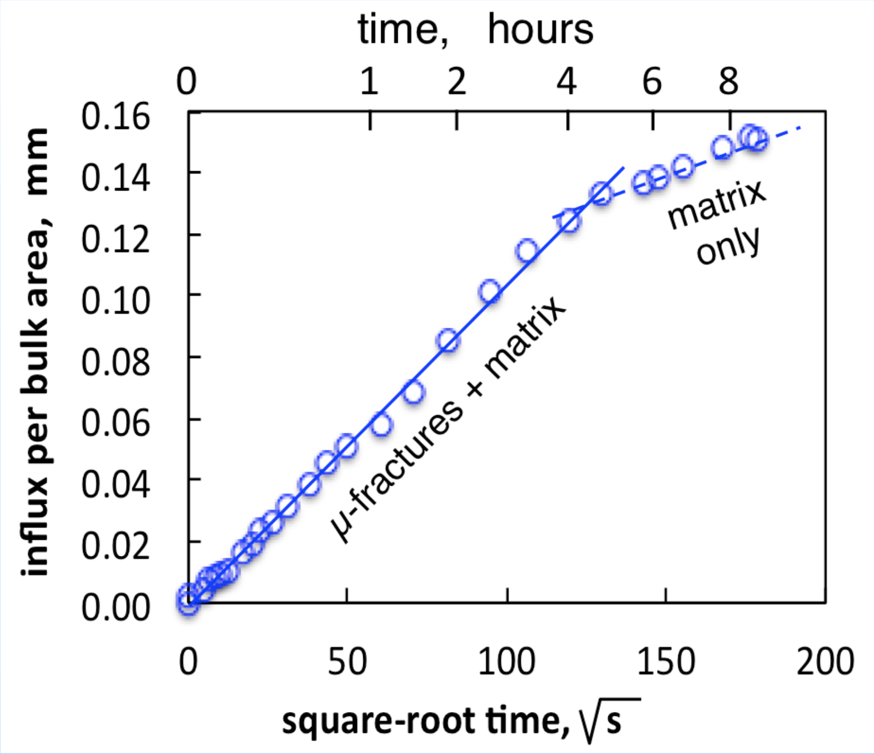




conceptual

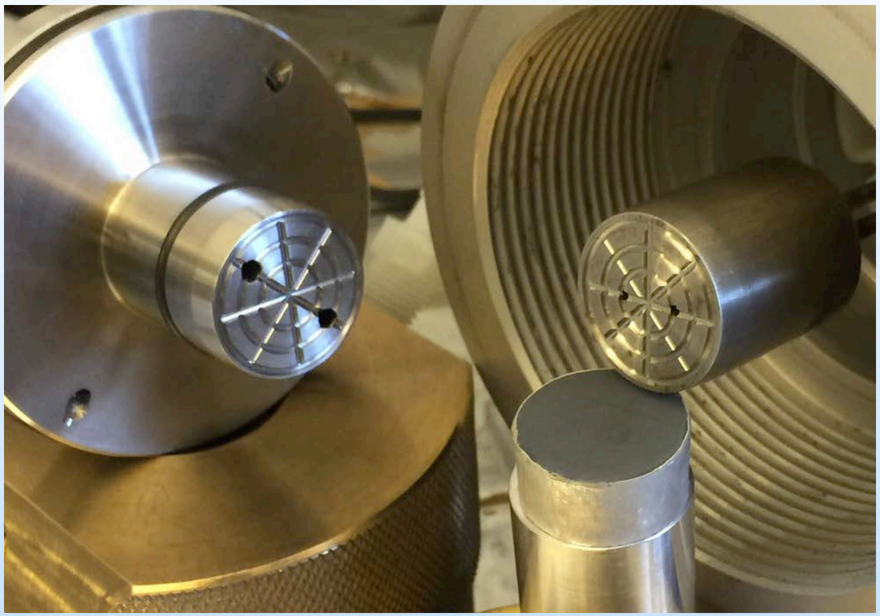
experimental

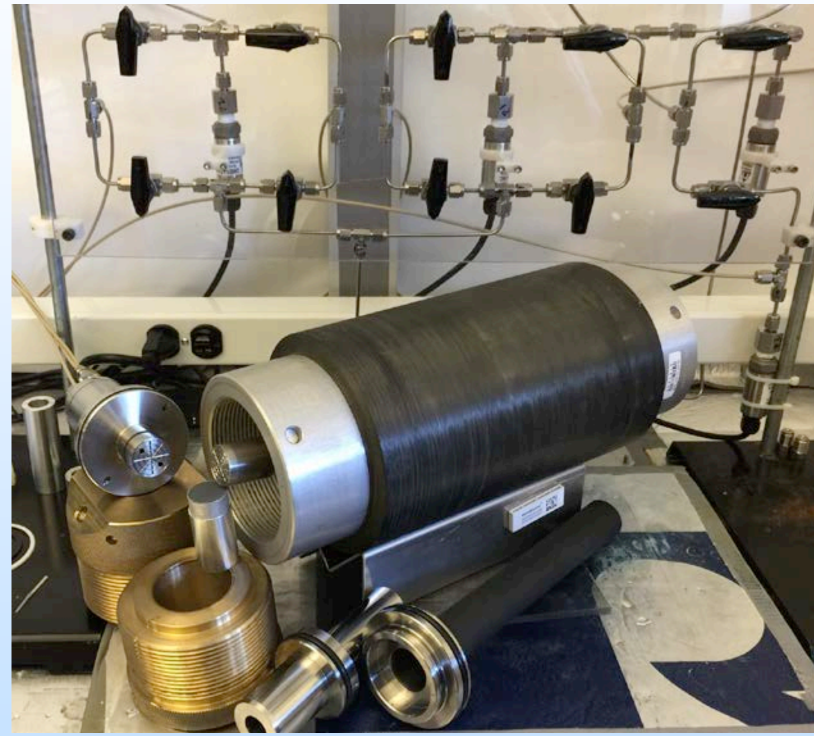
- Predominantly vertical hydraulic fractures supply fracturing fluids to primarily horizontal microfractures in shales.
- Initial imbibition enhanced via flow in microfractures (natural and stimulated).
- Imbibition into shale matrix over short and longer times.



Task 2C. Modifying core-flooding system for imbibition, water blocking

- Retrofitting existing core holder for narrower (23 mm) diam. and shorter (< 30 mm) sidewall core plugs.



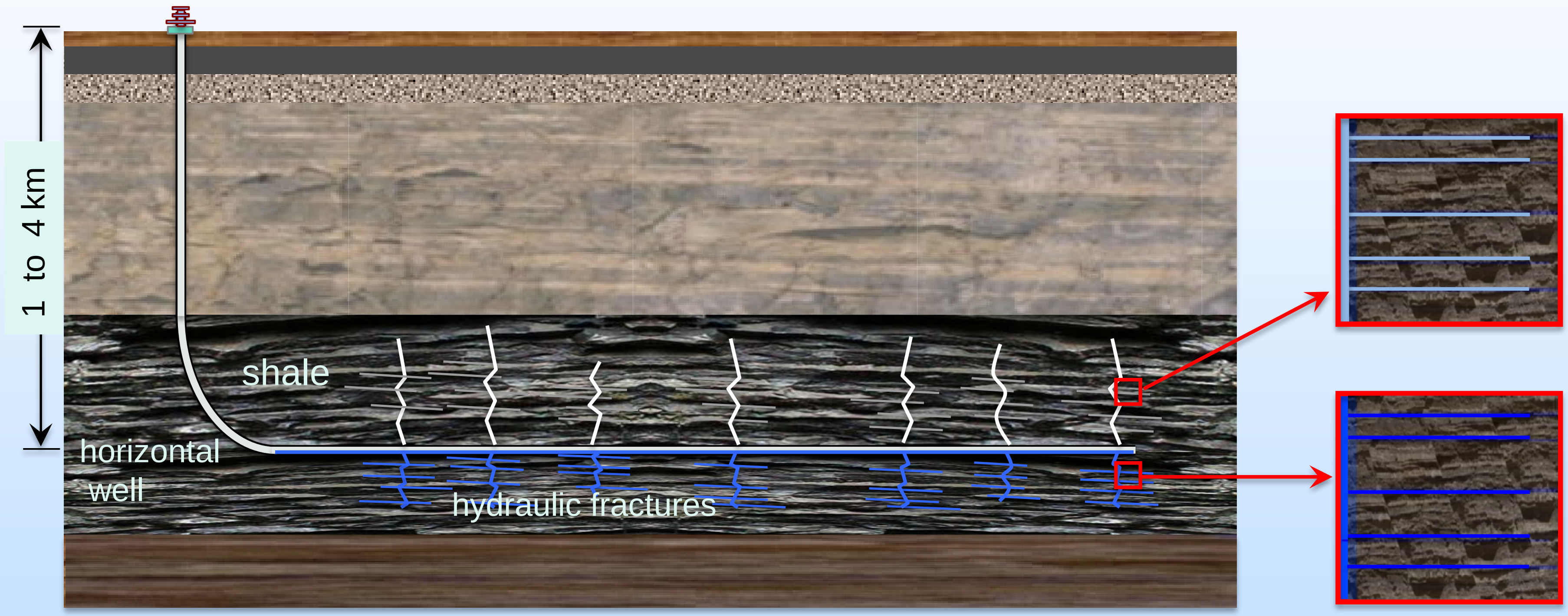


Tasks 2B, 2C. Next steps

- Quantify anisotropy in effective diffusion coefficients
- Water uptake in shale (under confinement) followed with gas counter-flow (ideally with XCT)

Evolving conceptual model for water-gas interactions in shale reservoirs

We envision that gravity drainage of water is important in fractures generated above horizontal wells, facilitates flow-back and gas production, and limits water blocking.



In addition, natural and stimulated secondary horizontal fractures connected to primary, above-well fractures should more easily drain.

Evolving conceptual model for water-gas interactions in shale reservoirs

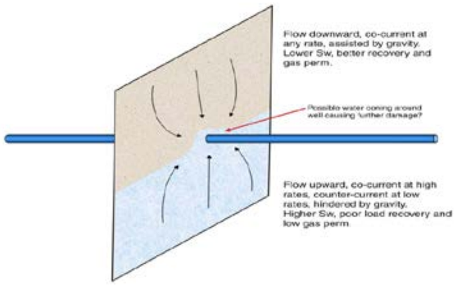
Gravity-drainage of fractures has been included in a few recent studies

Taylor et al., Canadian Soc. Unconventional Gas, 2011

CSUG/SPE 148680

Why Not to Base Economic Evaluations on Initial Production Alone

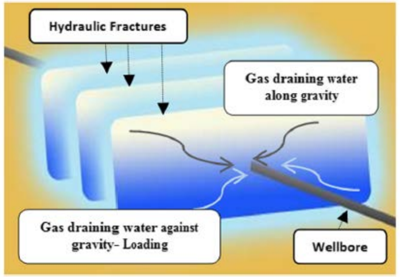
Robert S. Taylor, SPE, Halliburton; Robert Barree, Barree and Associates; Roberto Aguilera, University of Calgary; Ottmar Hoch, Hoch & Associates Inc.; Ken Storozhenko, KJS & Associates Ltd.



Agrawal & Sharma, J. Unconventional Oil & Gas Res., 2015

Practical insights into liquid loading within hydraulic fractures and potential unconventional gas reservoir optimization strategies

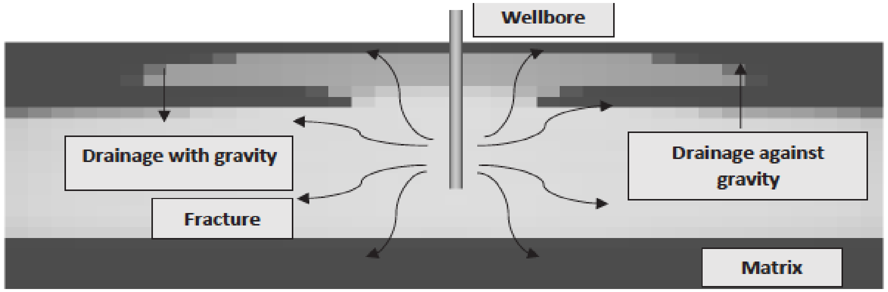
Samarth Agrawal *, Mukul M. Sharma



Sarkar et al., APPEA J., 2016, 369

A Cooper Basin simulation study of flow-back after hydraulic fracturing in tight gas wells

S. Sarkar, M. Haghighi, M. Sayyafzadeh, D. Cooke, K. Pokalai and F. Mohamed Ali Sahib



Further improvements in including gravity effects are possible, and being explored in Task 4.2.

Task 4. Modeling studies for understanding fluid flow and transport processes in shale matrix and matrix-fracture interfaces

Task 4A. Constitutive model development using pore-scale physics

- Improved a pore-scale modeling code for simulating multiphase flow in nanoporous media and micromodel experiments. However, as a priority we decided to focus on modeling at laminae and larger scales in this budget period for obtaining more informative results using the experimental data.
- Developed numerical and analytical models for diffusive transport with adsorption and analyzed the transient vapor adsorption measurements in shale laminae.
- Generated constitutive models for hysteresis in capillary pressure-saturation-relative permeability using pore-size distribution and connectivity information obtained from the equilibrium adsorption/desorption measurements of shales.

Modeling of diffusion and adsorption in shale laminae

- Employed both numerical and analytical models to understand the diffusive transport processes in shale samples.
- Starting with a general numerical model including the Maxwell-Stefan (MS) diffusion equations with Knudsen contribution, we developed analytical models for isotropic and anisotropic diffusive transport and linear adsorption in shale.

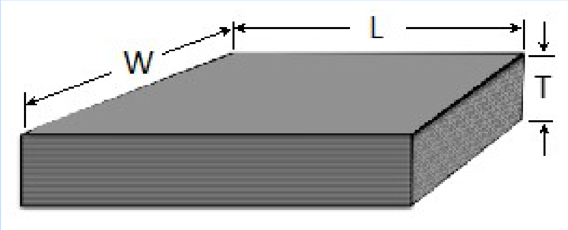
$$\textit{Mass flux of water vapor from the MS equations:}$$

$$J_{\mathrm{H_2O(g)}} = \frac{-p/(RT)M_{\mathrm{H_2O}}}{\left[\dfrac{1}{D_{K,\mathrm{H_2O}}} + \dfrac{1}{f(\phi)D_{\mathrm{H_2O-air}}} + \dfrac{x_{\mathrm{H_2O}}}{f(\phi)D_{\mathrm{H_2O-air}}}\left(\dfrac{D_{\mathrm{K,H_2O}}}{f(\phi)D_{K,\mathrm{air}}} - 1\right)\right]} \nabla x_{\mathrm{H_2O}}$$

$$\overset{\text{for } x_{\mathrm{H_2O}} << x_{\mathrm{air}}}{\Longrightarrow} \quad -D_{eff}\nabla c_{\mathrm{H_2O}} \quad (\textit{Fick's law of diffusion}),\ D_{eff} = \frac{1}{1/D_{K,\mathrm{H_2O}} + 1/(f(\phi)D_{\mathrm{H_2O-air}})}$$

- The analytical models verified with the more complex numerical model were used to interpret the experimental data for the adsorbed mass of water vapor at RH=0.32 in 3 shale blocks.

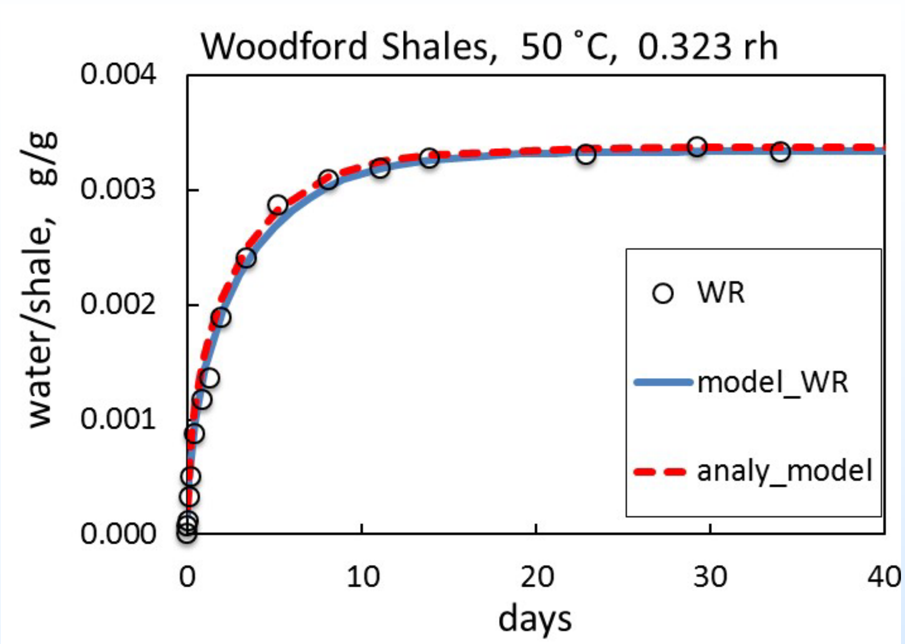
shale	WR	WD	WH1
porosity	0.081	0.070	0.100
L, mm	20.9	23.8	23.5
W, mm	11.8	12.3	13.1
T, mm	5.1	5.2	2.6



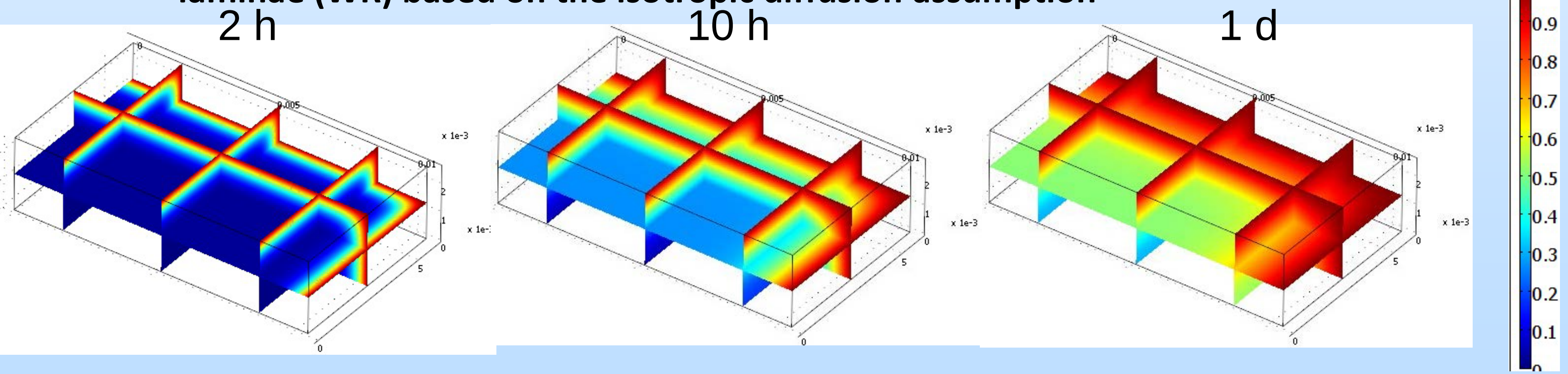
The analytical models were verified with the numerical models

Initial and Boundary Conditions:

- At t=0, water vapor concentration in the shale blocks ~ 0
- All the side boundaries are kept at saturation vapor concentration.



Temporal distribution of normalized vapor concentration within a shale laminae (WR) based on the isotropic diffusion assumption



(*Utilizing the symmetry, the numerical results are shown only for the quarter of the domain*)

Model Results for Isotropic and Anisotropic Diffusion Coefficients

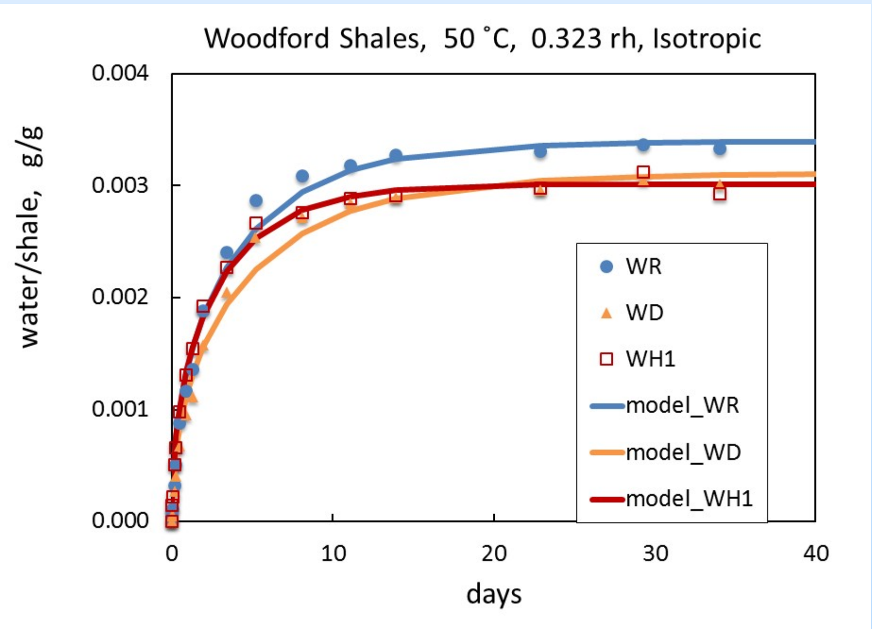
- Including anisotropy ratio as an additional parameter didn't improve the fit to the data
- Test for the anisotropy of the effective diffusion coefficient in shale samples was not conclusive. New experimental tests for quantifying transport properties in different directions will be important.

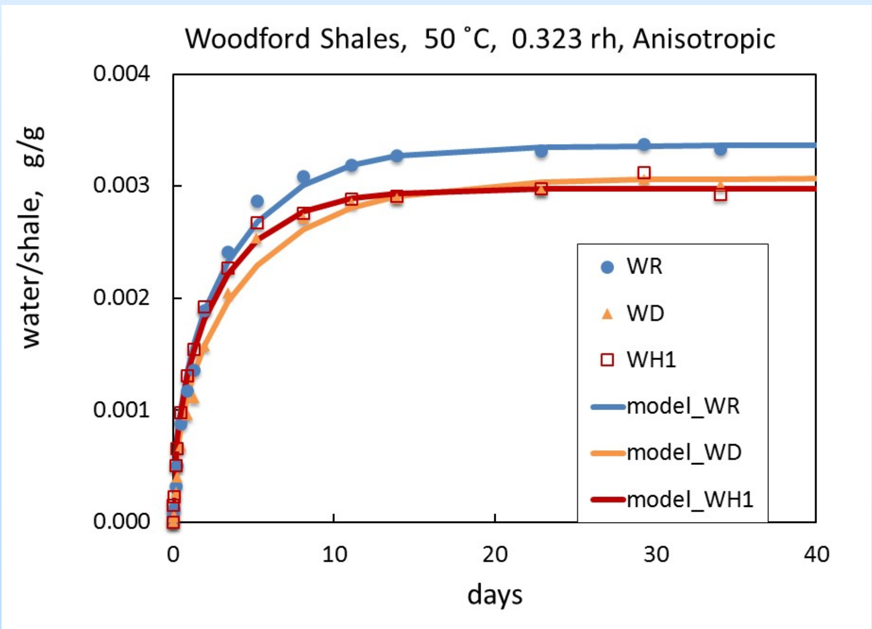
Isotropic conditions

	WR	WD	WH1
Porosity	0.081	0.070	0.100
Estimated D_{eff}, $m^2\ s^{-1}$	**1.48×10^{-8}**	**9.06×10^{-9}**	**2.78×10^{-8}**
Estimated K_d, $m^3\ kg^{-1}$	0.126	0.115	0.112
RMSE	1.56×10^{-4}	1.53×10^{-4}	7.90×10^{-5}

Anisotropic conditions

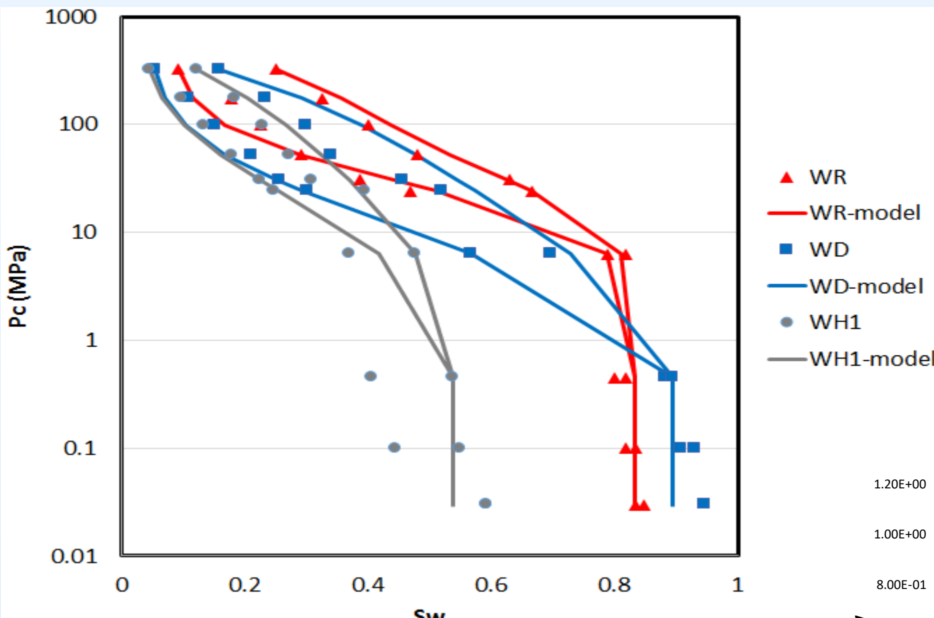
	WR	WD	WH1
Porosity	0.081	0.070	0.100
Estimated $D_{eff, H}$, (parallel to lamination) $m^2\ s^{-1}$	**6.82×10^{-8}**	**6.31×10^{-8}**	**7.25×10^{-7}**
Estimated $D_{eff, z}$, (orthogonal to lamination) $m^2\ s^{-1}$	**6.43×10^{-12}**	**1.18×10^{-11}**	**9.87×10^{-11}**
Estimated K_d, $m^3\ kg^{-1}$	0.124	0.114	0.110
RMSE	1.52×10^{-4}	1.49×10^{-4}	7.90×10^{-5}

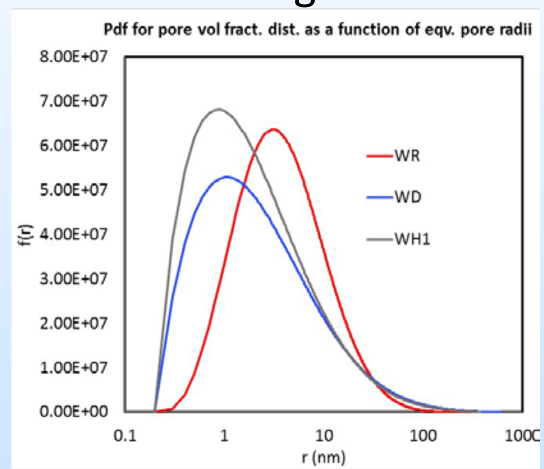


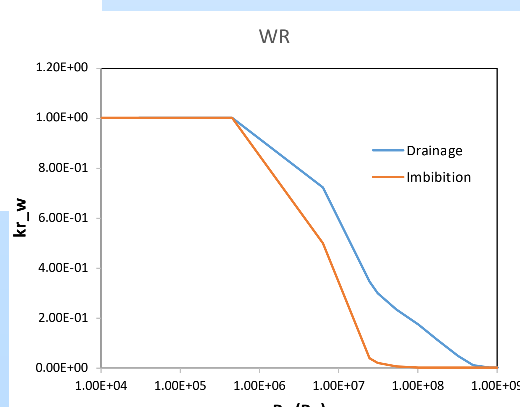


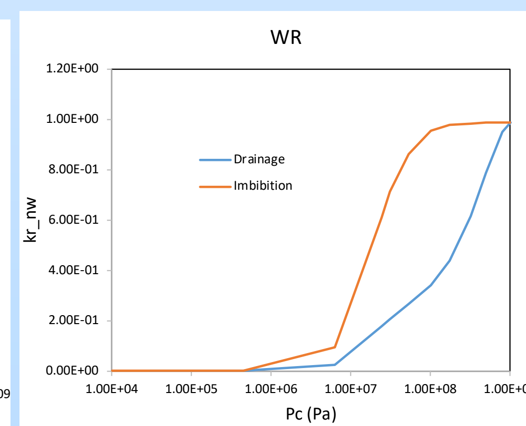
Ongoing Work: Estimation of hysteretic two-phase flow properties from the water vapor adsorption/desorption measurements in shale

- Using a hysteresis model for drainage and imbibition (Cihan et al., 2004, 2007 in WRR), we estimated pore-size distribution and connectivity function parameters for the different shale samples.
- We generated Pc-S-krw-krn functions, which will be used for analyzing core-scale experiments and testing various hypothesis related to water blocking at fracture-matrix system (Task 4.2) at field-scale





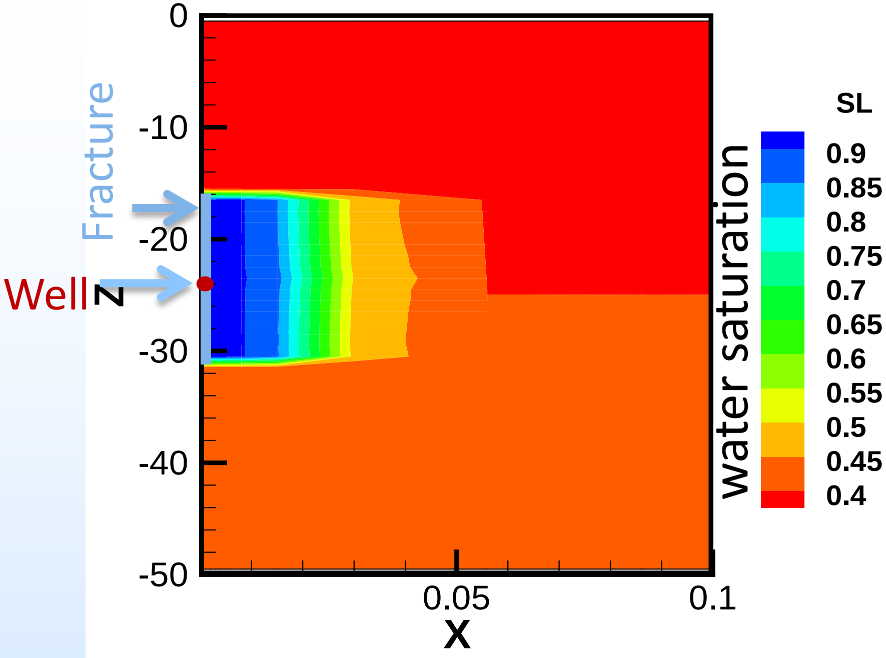




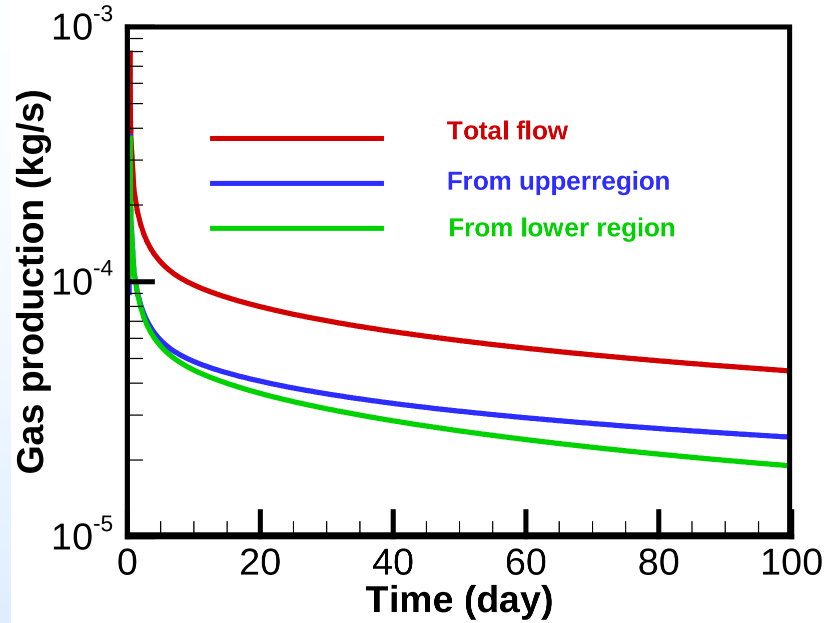
Task 4B Activities: Model water and non-water fluids at fracture-matrix interface

- Model Water Imbibition Tests
  - TOUGH2/iTOUGH2 with EOS3
  - Estimated parameters for shale samples and their uncertainties. Permeability, entry pressure and parameter *n* (pore-size distribution index) are most influential parameters parameters
- Examine Gravity Effect with Horizontal Well Production
  - TOUGH2/iTOUGH2 with EOS CH4
  - A simplified 2D model with vertical fracture

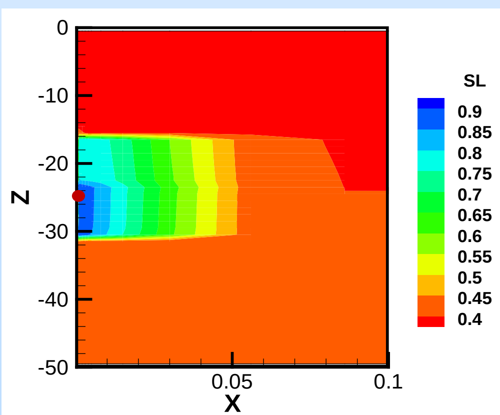
Modeling gravity efects in horizontal well production



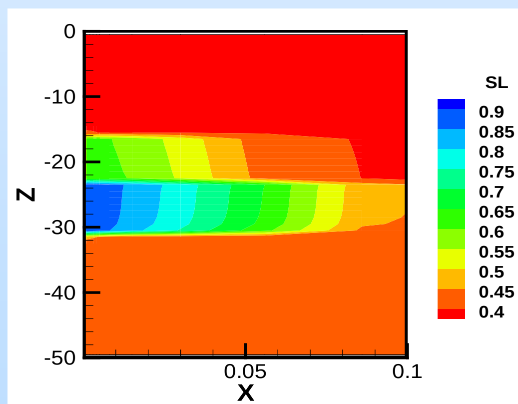
At end of 2 hour injection



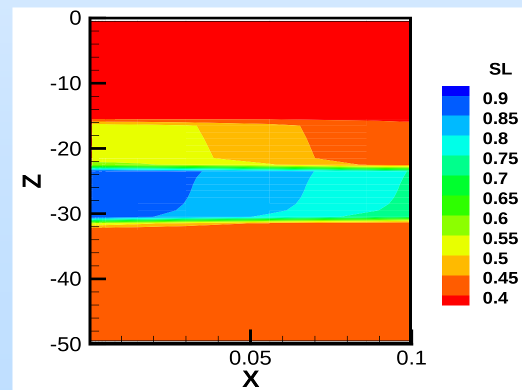
flux is based on 1m thickness in Y direction



At day 1



At day 10



At day 100

Task 4B Lessons Learned

- More water is produced from the upper region during initial production period
- Initially gas production appears to be insignificantly higher from lower than upper region due to a slightly higher gradient
- At later times, a significant amount of injected water is left in the lower region due to gravity effects, leading to reduced gas production compared to the upper region
- Without initial water injection (scenario 2, not shown here), no significant difference is observed between upper and lower regions

Task 3.0. Non-Water Stimulation Fluids

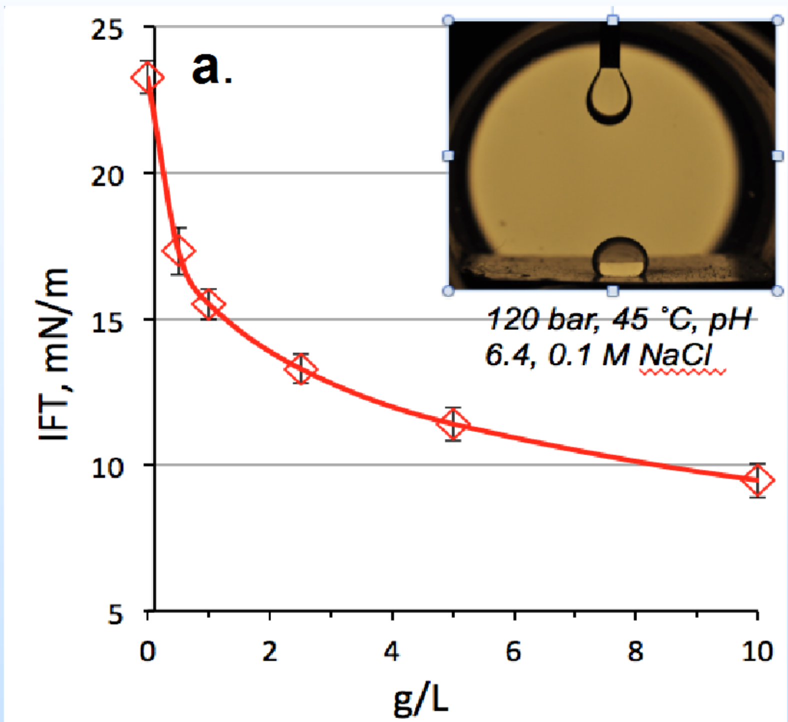
(Recently added Task to the current budget period, previously funded by LDRD, Jiamin Wan et. al)

Subtask 3.1. To develop and improve methods for controlling viscosity of non-water fracturing fluids.

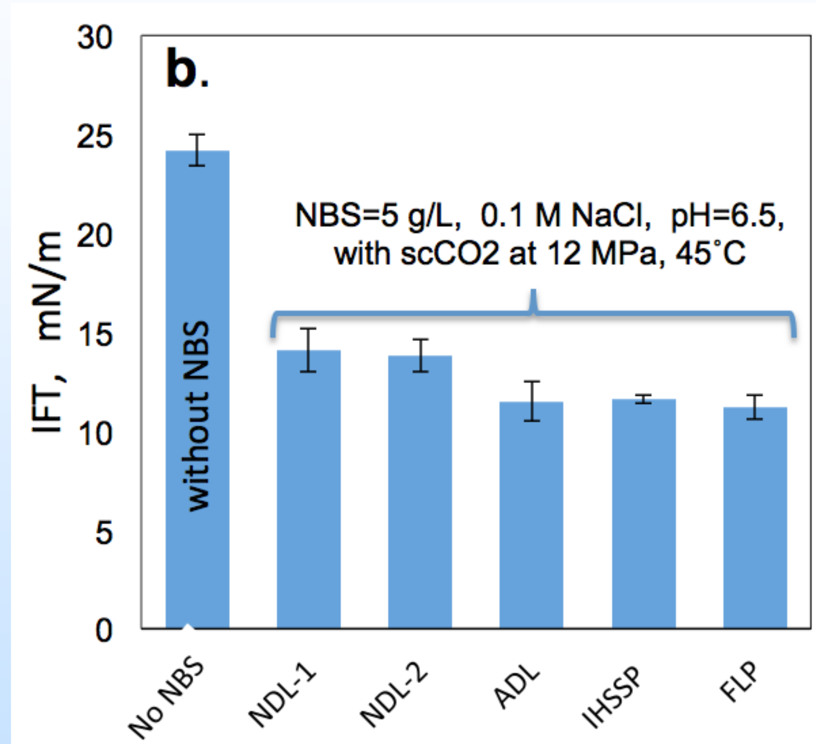
Subtask 3.2. To better understand how different fracturing fluids impact gas/oil counter-flow, with the emphasis on interfacial properties.

Approaches. The experiments will be conducted under reservoir-relevant pressure, temperature, and chemistry conditions, at pore network and core scales.

Measuring Interfacial tension (IFT) of $scCO_2$ - NBS solutions



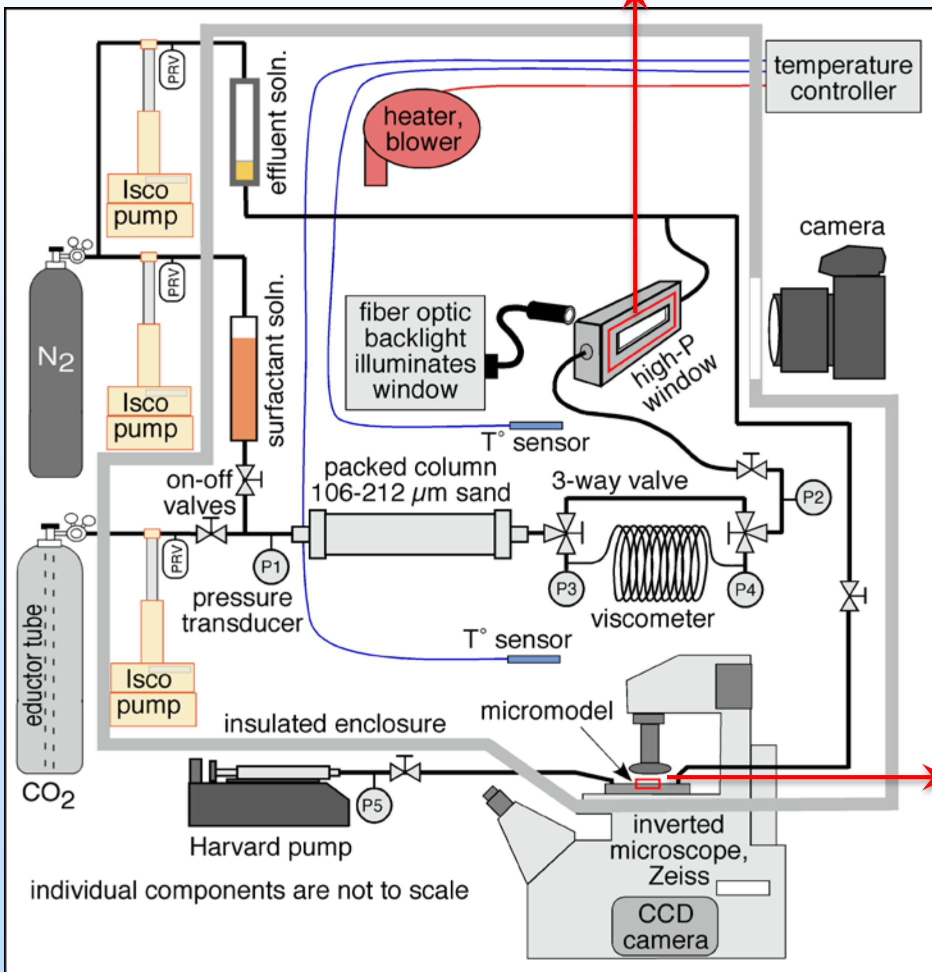
(**a**) Image of equilibrium NBS solution droplet within $scCO_2$ at 12.0 MPa and 45˚C. The IFT values were calculated from the image.



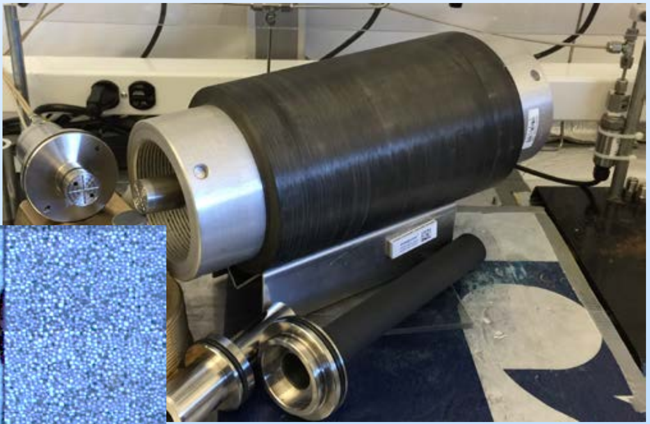
(**b**) IFT values of NBS extracted from different source humus.

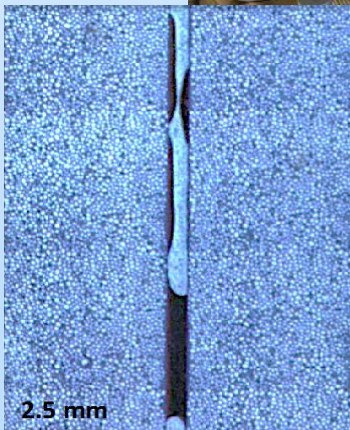
NBS is a effective surfactant.

Task 3.0 Next Budget Period



- To publish a paper on the NBS results.
- To finish the high-P/T microfluidics setup (have being working on), and test the NBS-$scCO_2$ foams and other non-water fracturing fluids at pore network scale.
- ***Future study***: To understand through testing the stimulation fluids at high P-T core scale.





Accomplishments to Date

- Comprehensive analyses of shale-water retention relations.
- Quantification of diffusion-limited equilibration in shale.
- Improvement of conceptual models (gravity, hysteresis, wettability).
- Alternative, low-water, high-pressure foams being tested.
- Publications in all of the above are in review or in progress.

Synergy Opportunities

- Understanding of water imbibition-redistribution patterns in shale will be gained through collaborations with shale micro-tomography expertise at NETL (Dustin Crandall).
- Development of alternative low water content stimulation fluids will be pursued through industry collaborations (Liang Xu, Multi-Chem, Halliburton).
- We are open to developing collaborations with other groups interested in multiphase flow in shales, particularly at complementary scales.

Project Summary

- Comprehensive analyses of shale-water retention relations.
- Quantification of diffusion-limited equilibration in shale.
- Improvement of conceptual models (gravity, hysteresis, wettability).
- Characterizing alternative, low-water, high-pressure foams.
- Publications in all of the above are in review or in progress.

Next Steps

- Measure and model anisotropic effective diffusion coefficients.
- Improvement of conceptual models (gravity, hysteresis, wettability).
- Develop low-water, alternative high-pressure foams.

Acknowledgments

- NETL: Stephen Henry, Jared Ciferno, Dustin Crandall, Robert Vagnetti, and Jonathan Moore
- Oklahoma Geological Survey, Brian Cardott: (Woodford Shale)
- MSEEL (Marcellus Shale)
- LBNL: Stefan Finsterle, Yongman Kim, Weijun Shen

Appendix

– These slides will not be discussed during the presentation, but are mandatory.

Benefit to the Program

Program Goal: address critical gaps of knowledge of the characterization, basic subsurface science, and completion/stimulation strategies for tight oil, tight gas, and shale gas resources to enable efficient resource recovery from fewer, and less environmentally impactful wells.

Linking our project to the Program:

- Gain understanding of water in unconventional reservoir stimulation through studies of water imbibition, redistribution, and gas counter-flow.
- Reduction in water use must be based on understanding of water dynamics in shale matrix pores and fractures.

Project Overview
Goals and Objectives

Goals and Objectives:

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

Project Team

- Tetsu K. Tokunaga
  - Immiscible fluid phase equilibrium and flow.
- Jiamin Wan
  - Surface chemistry, wettability, low-water foams.
- Abdullah Cihan
  - Pore- to core-scale modeling of immiscible fluids.
- Yingqi Zhang
  - Continuum modeling of fracture-matrix systems
- Yongman Kim
  - Science-engineering associate
- Weijun Shen
  - Graduate student assistant, now assistant professor

Gantt Chart

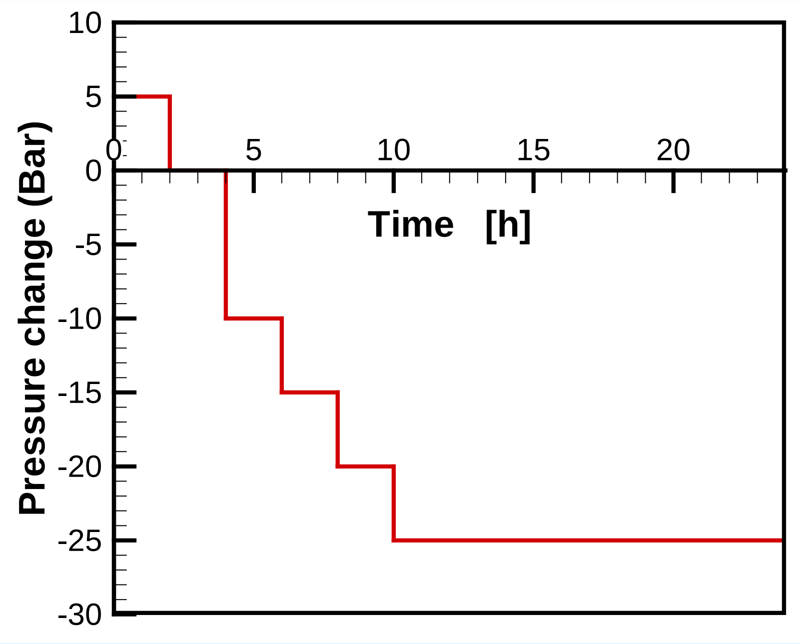
Tasks	Year 1				Year 2			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
start date	10/1/16	1/1/17	4/1/17	7/1/17	10/1/17	1/1/18	4/1/18	7/1/18
end date	12/31/16	3/31/17	6/30/17	9/30/17	12/31/17	3/31/18	6/30/18	9/30/18
1. Project Mgmt. Plan								M
2. Shale Properties, equilibrium and flow experiments								
2A. Shale water saturation vs capillary pressure	m	M						
2B. Water imbibition into shales				m		M		
2C. Gas permeabilities at specific saturations						M		
2D. Countercurrent water uptake and gas flow							m	M
3. Non-water fracking fluids experiments								
3A. Micromodel design & construction	m							
3B. Optimize experimental setup and procedures			m		M			
3C. Compare water-based vs CO2-based fluids						m		M
3D. Test other non-water fracturing fluids							m	M
4. Modeling								
4A.1. Multicomponent diffusion-adsorption model				M				
4A.1. Improved hysteretic two-phase flow models								M
4B. Model fluids at fracture-matrix interfaces								M

“m” denotes minor milestone completion; “M” denotes major milestone completion

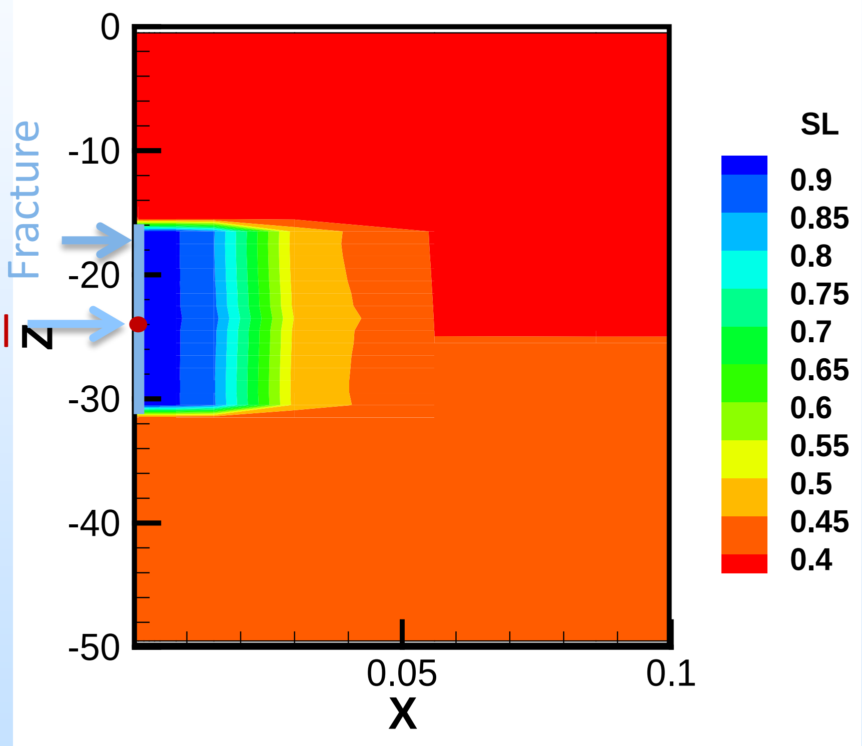
Current Budget Period Summary: October 2016 – July 2017

Gravity Effect

Scenario 1: Water injection for 2 hours to mimic hydraulic fracturing process, 2 hours shut-in, then production



Injection/production pressure
Reference pressure: 15 MPa



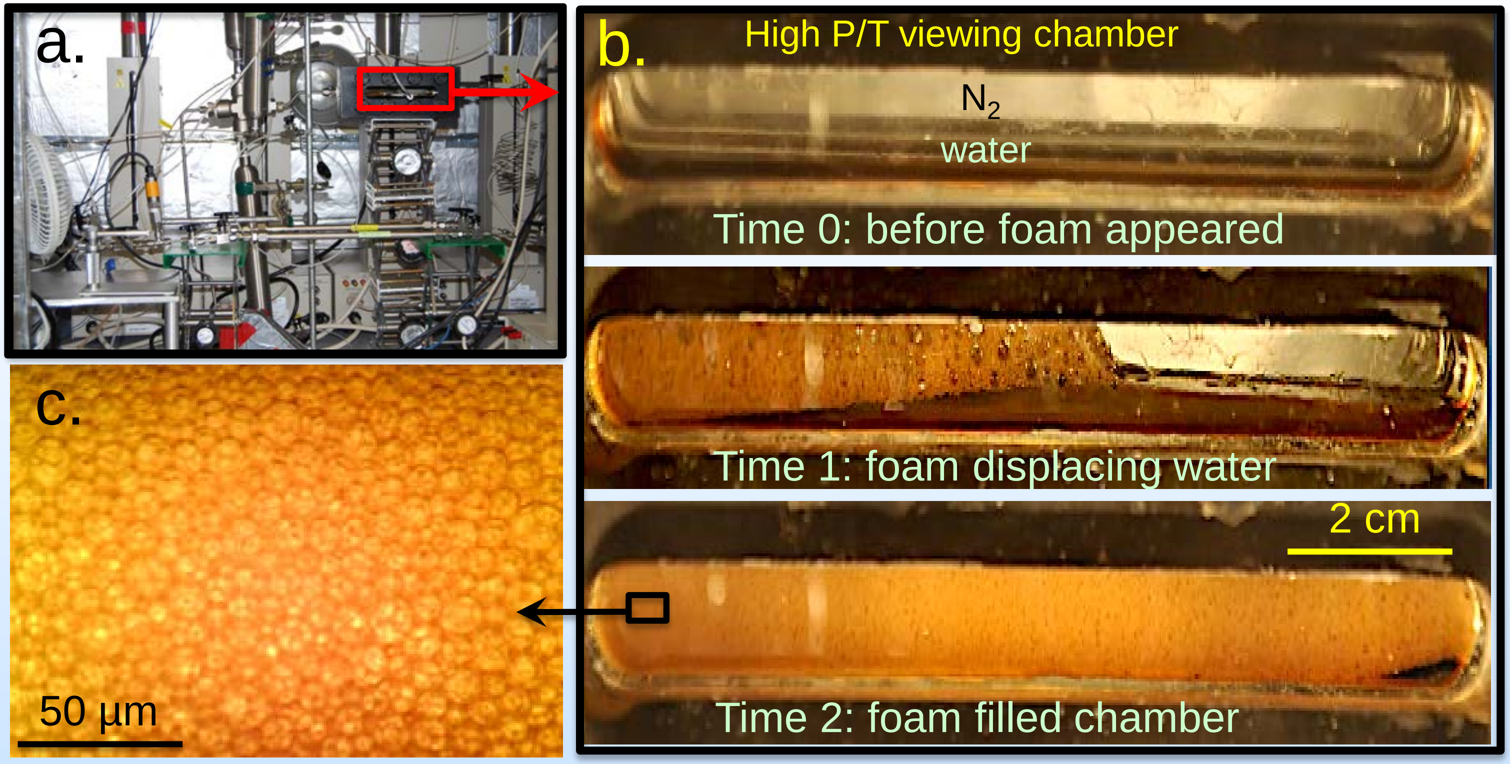
Liquid saturation after 2 hours of injection

Fracture aperture: 1 mm
Matrix permeability: 5×10^{-18} m^2

Permeability: 10 darcy
Porosity: 5%

Using **Natural Biosurfactant (NBS)** to Manipulate Fluid Viscosity

NBS Stabilized $scCO_2$ foam



(a) Photo of foam generator and rheometer for supercritical fluid foams

(b) Observing the foam flow through a high-P viewing window.

(c) A close look at the foam. $scCO_2$ bubble sizes ~10 µm.

This foam has 90% $scCO_2$, viscosity 30 cP (x500 high than pure $scCO_2$). 0.5% NBS and 0.58% NaCl are the only additives in aqueous phase. 12 MPa, 45 ˚C.

NBS alone generated excellent $scCO_2$ foam