Understanding Water Controls on Shale Gas Mobilization

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Acknowledgments

- DOE-NETL
  - Jared Ciferno
  - Stephen Henry
- Oklahoma Geological Survey (Woodford Shales)
  - Brian Cardott
- LBNL (laboratory and computational resources)
- Institute of Porous Media Flow and Fluid Mechanics, Chinese Academy of Sciences

Presentation Outline

- Background, motivation
- Materials, methods
- Equilibrium relations
- Transport properties
- Pore-scale to continuum modeling
- Next steps

Benefits 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.

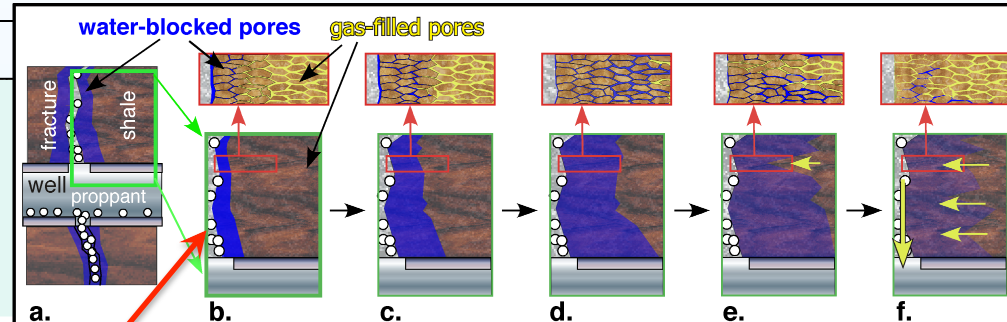
Linking our project to the Program:

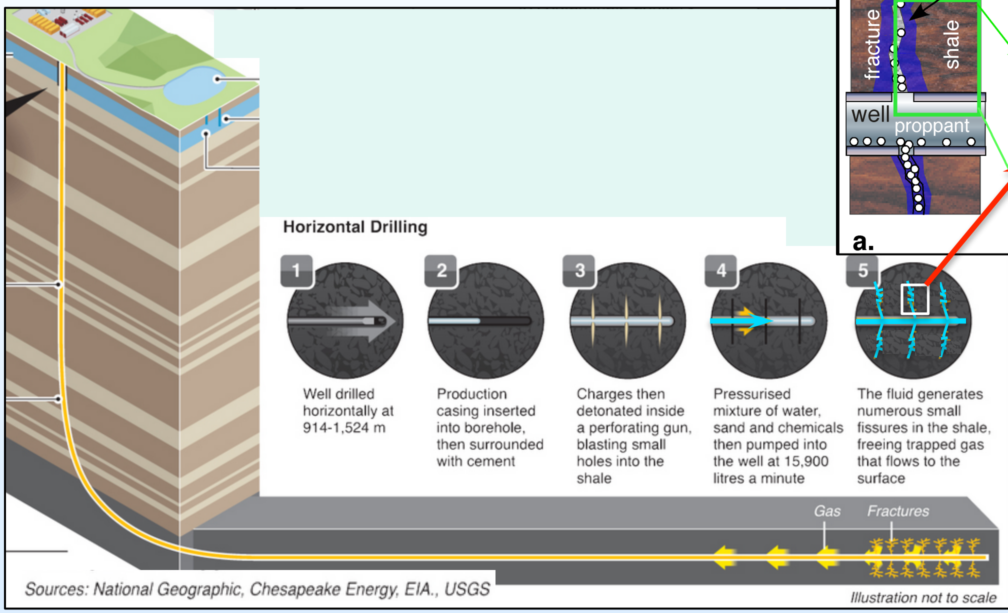
- Gain understanding of water in unconventional reservoir stimulation through studies of water imbibition, redistribution, and gas counter-flow.
- Reduction in water use must be based on understanding of water dynamics in shale matrix pores and fractures.

Project Overview:
Goals and Objectives

- Improve understanding of the physicochemical basis of immiscible fluid phase equilibrium and flow in shales.
- Improve understanding of transient immiscible fluid interactions controlling gas recovery from microfracture networks in nanoporous shale matrix blocks.

Background, Motivation



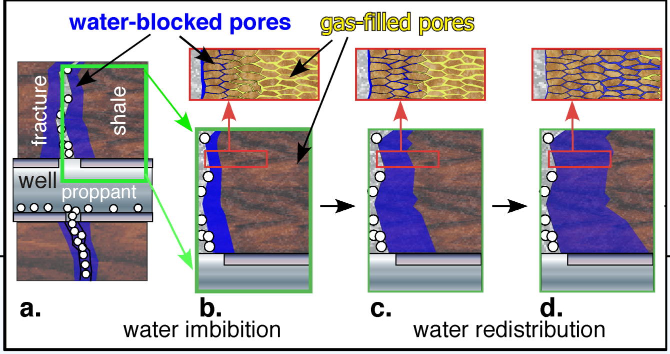


Water in the shale matrix (native and injected) interferes with gas flow.

Conceptual illustration of water-based fracturing fluid and proppants entering newly formed fractures from horizontal well, water imbibition into low permeability shale matrix and blockage of gas flow into fracture, water redistribution, and eventual gas breakthrough.

BERKELEY LAB Lawrence Berkeley National Laboratory
Energy Geosciences EARTH & ENVIRONMENTAL SCIENCES AREA
NETL NATIONAL ENERGY TECHNOLOGY LABORATORY
U.S. DEPARTMENT OF ENERGY

Background, Motivation



Key Gaps and Unknowns:

- Where does most of the water (hydraulic fracturing fluids) go? Often, only ~20% is recovered.
- How permanent (versus reversible) is damage from water-blocking?
- What are threshold water saturations and activities needed for gas flow?

Research Needs:

- Understand multiphase fluid (water, gas) equilibrium and flow in shales
- Direct measurements under controlled water and gas phase activities (pressures)
- Develop predictive capabilities for gas and water flow in shale matrix

Laboratory-based studies completed and ongoing

- ✓ Physicochemical characterization of Woodford shale
- ✓ Equilibrium capillary pressure-saturation relations
- ✓ • Water and gas flow
- Water and gas flow
- Waterless stimulation fluids studies

Laboratory studies: Woodford Shales from Oklahoma Geological Survey

Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

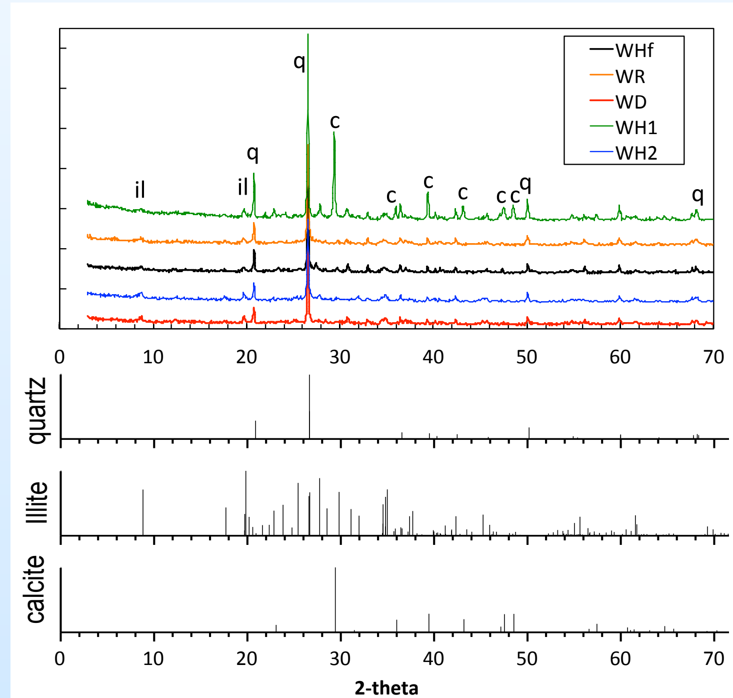
OKLAHOMA GEOLOGICAL SURVEY

A State Agency For Research and Public Service

Laboratory-based studies: chemical, physical, & mineralogical characterization

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

LBNL#	Al, %	Si, %	P, %	S, %	K, %	Ca, %	Ti, %	Mn, %	Fe, %
WHf	9.1	22	0.1	0.3	3.5	1.2	0.4	0.09	3.1
WR	6.6	32	0.1	0.9	3.3	1.0	0.3	0.04	2.0
WD	8.6	30	0.1	0.3	4.3	1.3	0.3	0.03	3.0
WH1	4.8	22	0.1	0.1	1.8	11.7	0.2	0.01	1.0
WH2	10	38	0.2	0.2	5.2	2.4	0.5	0.02	2.1



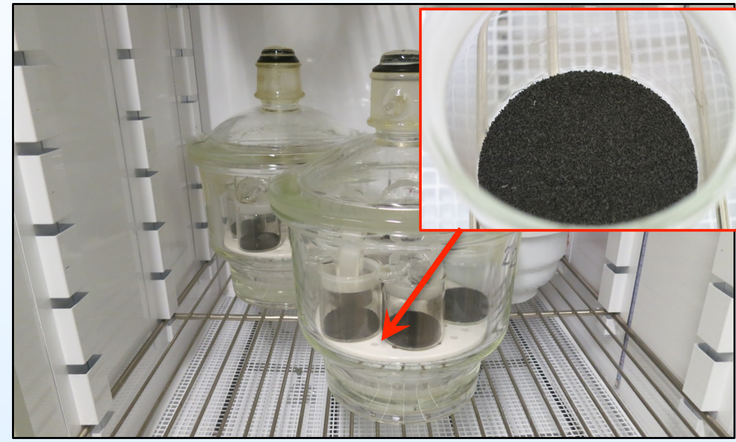
LBNL label	Well	mineralogy
WHf	Hoffman	q, il
WR	Roetzal	q, il
WD	Dunkin	q, il
WH1	Holt	q, il, c
WH2	Holt	q, il

main minerals
q = quartz
il = illite
c = calcite

Laboratory-based studies: Equilibrium water retention in shale matrix needs to be understood to predict water blocking

How strongly is water retained on these shales?

Capillary pressure-saturation relations are needed to understand water uptake/release, and gas flow.



Shales were equilibrated under controlled temperatures and water vapor pressures, and controlled capillary pressures.

Capillary pressure (P_c) is approximately related to relative humidity (P/P_o) through

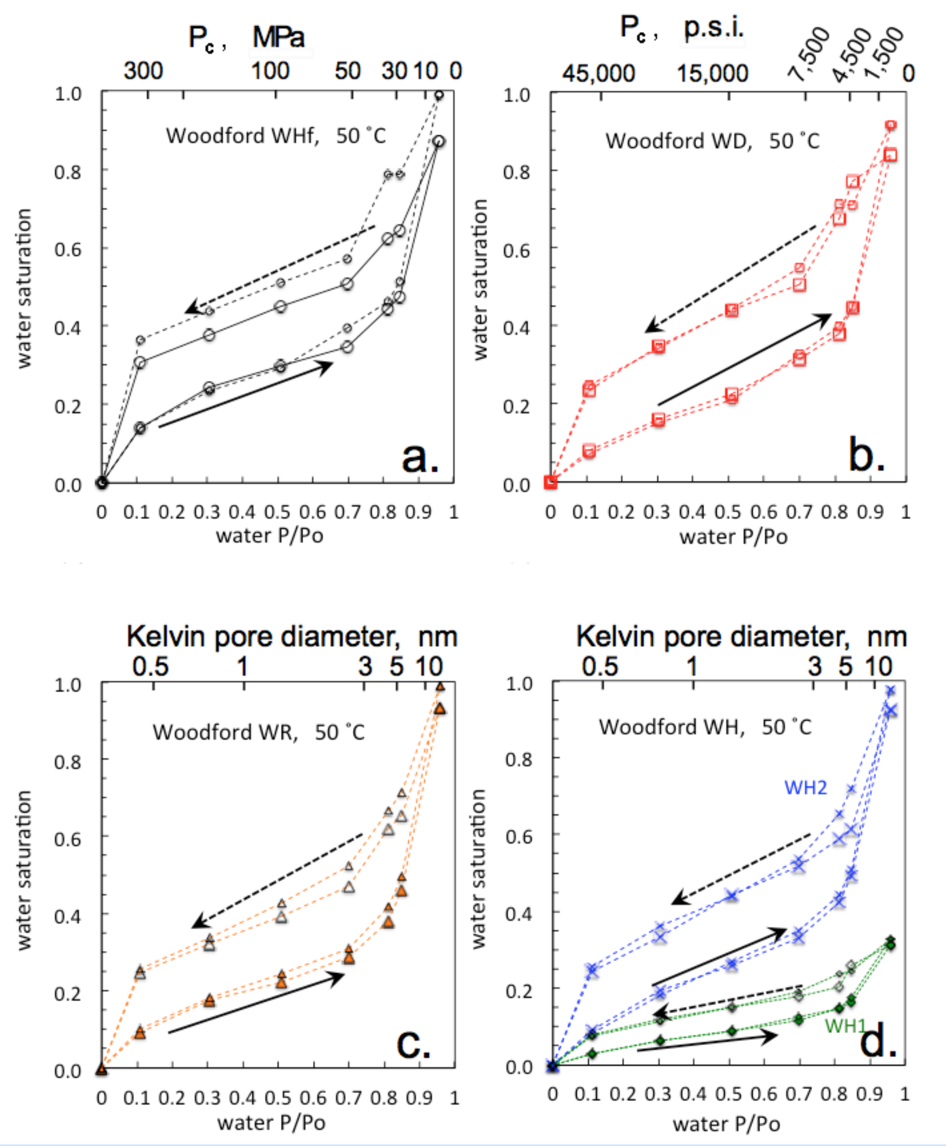
$$P_c \approx \frac{-\rho_w RT}{M_w} \ln \frac{P}{P_o}$$

where R is the gas constant, T is the Kelvin temperature, M_w is the molecular weight of water, and ρ_w is water density.

Laboratory studies: Water vapor adsorption/desorption isotherms

Adsorption and desorption isotherms were obtained at 50˚C on crushed shales in the 500-850, and 250-500 µm size fractions, under controlled relative humidity (P/P_o).

- Practically identical curves from the two grain-sizes.
- Large hysteresis in water saturations over the full range of conditions.
- Matrix pores finer than ~3 nm likely to remain water-filled.
- Very high P_c needed to diminish water blocking, <u>suggesting that reservoir recovery from water blocking can take long times</u>.
- Calcite-rich shale retains less water.

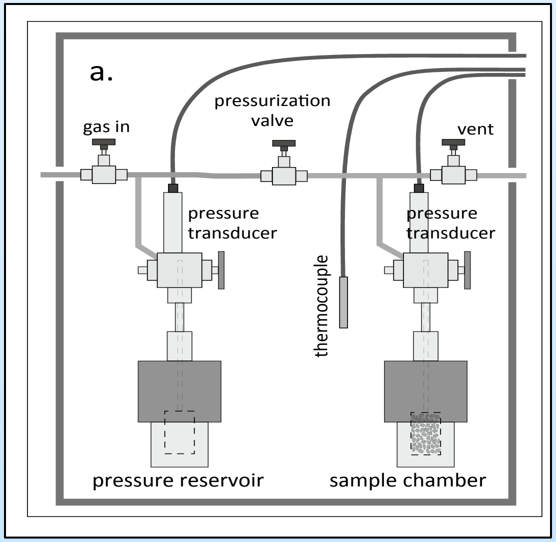


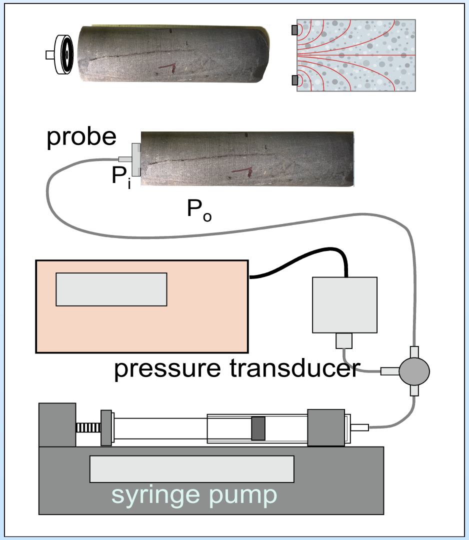
Applying several approaches for characterizing gas and water flow in shales

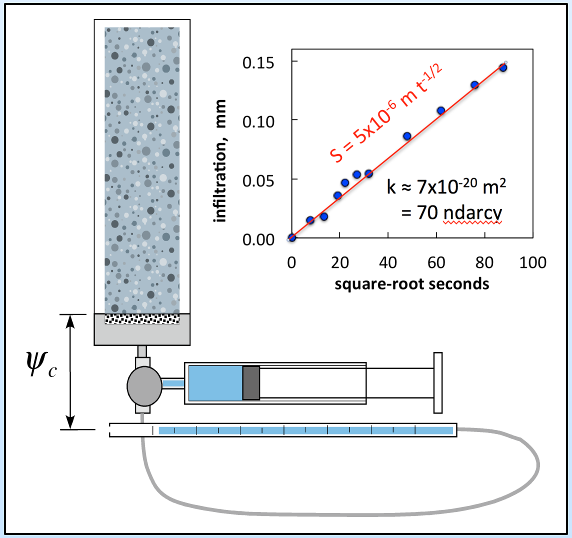
Gas pressure pulse decay measured on crushed shale: intrinsic nanoporous matrix permeability.

Gas probe permeameter measurements on shale cores: sensitive to fractures, microfractures, and stress.

Water imbibition tests: sensitive to permeability, interfacial tension, and wettability







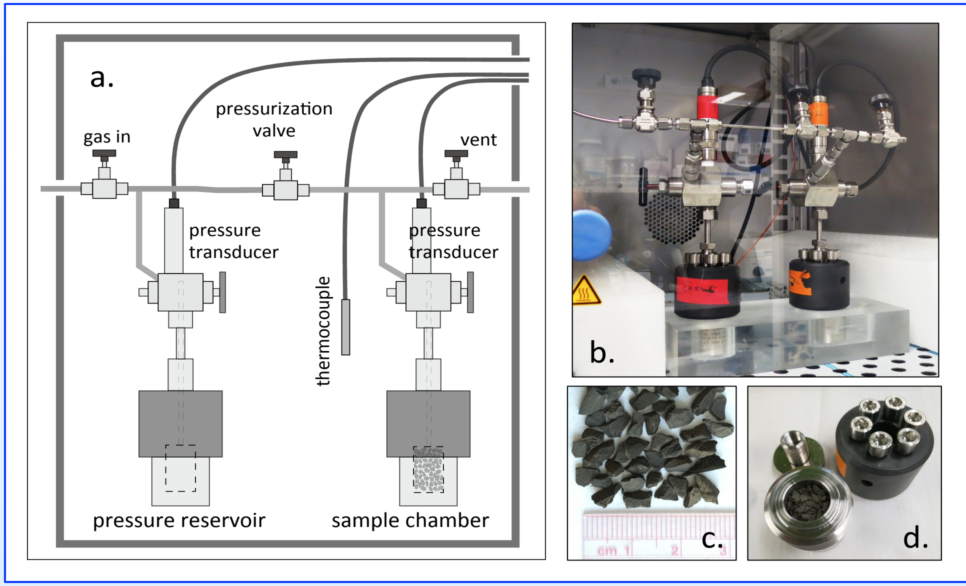
Laboratory-based studies on gas flow in shales show the importance of permeability heterogeneity at small scales

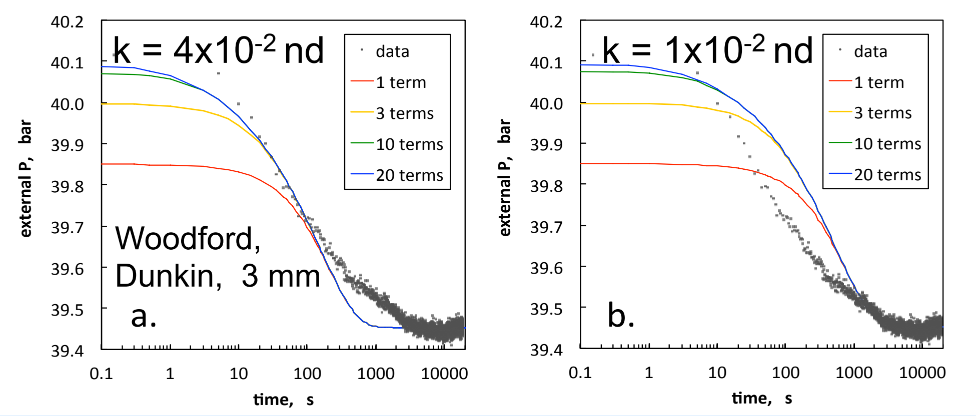
The gas pressure pulse decay method is applied on well-sorted crushed shale grains, with permeability (k) calculated assuming radial gas flow into spherical grains of uniform size (Luffel et al., 1993).

However, our measurements are not fit well by the model.

Grains are angular, of finite size range, and likely varying in k.

Experimental data are better represented by mixtures of grain-sizes. This issue was recently addressed by Mikey Hannon (Transport in Porous Media, 2016).





Modeling-based studies completed and ongoing

- ✓ Developed a pore-scale model for simulating multiphase flow in nanoporous media
- ✓ Tested the new code with existing model results for relatively simple problems
- Compare model-predicted shale matrix properties with experimental data
- Test/improve macroscopic-scale models with experimental data

A new pore-scale modeling tool was developed and verified with existing results for simplified geometry and problems

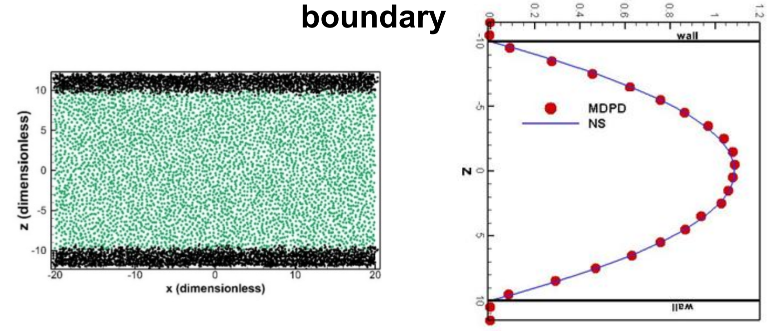
Objectives

- Improve understanding of pore-scale physics and emergence of macroscopic phenomena
- Develop and test macroscopic models relevant for shale matrix and matrix-fracture multiphase flow exchange.

Many-body dissipative particle dynamics (MDPD)

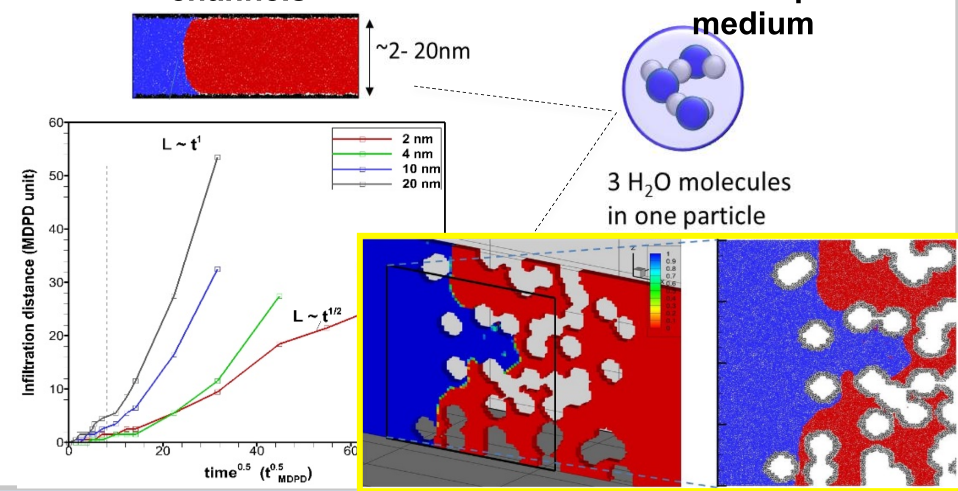
- System is represented by a set of interacting particles and each particle represents a small cluster of atoms or molecules. Evolution of particles in space and time is governed by Newton's equation of motion.
- Can naturally represent slip flow, wettability, dynamic contact angle changes and adsorption/desorption processes.
- Model parameters obtained from macroscopic fluid properties such as interfacial tension, viscosity, density, contact angle.

Single-phase flow: Verification against the Navier-Stokes-model results with no slip boundary



Two-phase flow in nano-scale channels

Forced imbibition into an idealized porous medium



Ongoing testing of macroscopic two-phase flow theory using experimental data

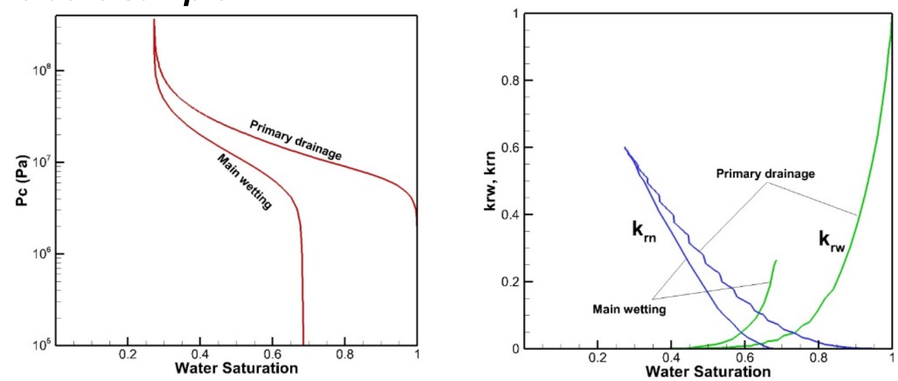
Objectives

- Assess applicability and shortcomings of existing macroscopic models
- Develop and test improved theory and models using experimental data and pore-scale modeling

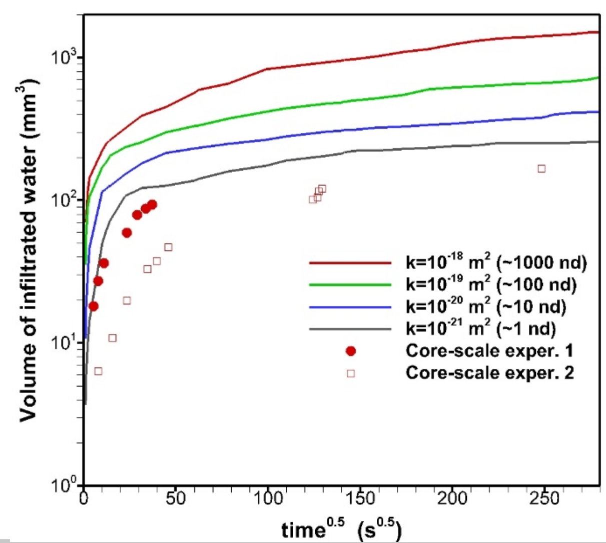
Is traditional two-phase flow theory applicable for representing drainage and imbibition in shale rock cores?

- Preliminary analyses conducted by using core-scale experimental data and a new hysteretic two-phase flow model.
- The model contains new hysteretic constitutive relationships (Pc-S-krw-krn) developed using basic pore-scale physics of capillary flow and void space connectivity (Cihan et al., 2014-2016).

Generated Pc-S-krw-krn functions for primary drainage and main imbibition, using void volume distribution and connectivity functions for representing shale properties at the core sample



The simulations run with different intrinsic permeability values indicate that the effective permeability of the core is at a nanodarcy range.



$$L_{data} : t^{0.4-0.5}$$

Accomplishments to Date

Experimental Studies

- Basic physicochemical properties of Woodford shales were determined.
- Equilibrium properties for water interactions with shales were measured:
  - Water imbibition and drainage relations
  - Wettability.
- Transport properties: several approaches for measuring water and gas flow in shales.

Modeling Studies

- A new pore-scale modeling tool based on many-body dissipative particle dynamics method was developed and verified with existing solutions for simplified geometry and problems. This model helps improving knowledge of pore-scale physics and developing macroscopic models.
- Started developing and testing macroscopic-scale models with experimental data to predict shale matrix and matrix-fracture multiphase flow exchange processes at larger scales.

Summary: Experimental

Experimental findings and lessons learned:

- Desorption isotherms show that most of the Woodford shales have very high gas entry (water drainage) capillary pressures and large capillary hysteresis.
- Multiscale nature of permeabilities reflect importance of microfracture networks through very low permeability matrix.
- Wettability strongly influences water imbibition into shale matrix, and limits predictions of water uptake.

Future Plans for Experimental Investigations:

- Water imbibition, redistribution, and gas counterflow experiments under varied initial water saturation and system pressures.
- X-ray micro-computed tomography of water distributions at later stages of imbibition and gas counter-flow.
- Testing of oil recovery with alternative, nonwater-based fracturing fluids in matrix-fracture micromodels.

Summary: Modeling

Modeling findings and lessons learned:

- A new MDPD modeling preliminarily indicates that the interface front advances into nano-scale channels appeared to be proportional to the time ($L \sim t$), rather than $L \sim t^{1/2}$, predicted by the Lucas-Washburn (LW) equation.
- Preliminary testing of the traditional two-phase flow model with the hysteresis for water imbibition in shale cores shows that the model under predicts measured imbibed fluid volumes. More robust tests will need to be conducted in the future for better understanding the limitations.

Future Plans for Modeling Investigations:

- Pore-scale modeling will need to be done at larger spatial and temporal scales to investigate imbibition and redistribution of fluids. This will provide assessment of water blockage at macroscopic scales and help develop upscaling strategies for macroscopic modeling.
- Continue pore-scale and continuum modeling studies to understand underlying flow mechanisms and to determine relevant effective parameters for developing upscaling strategies and macroscopic models.

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. In particular, our studies at the scales of interfaces, pores, and cores are complementary to larger (up to reservoir) scale investigations.

Appendix

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

Project Team

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

Gantt Chart

quarter	Q1	Q2	Q3	Q4	Q5	Q6
start date end date	Oct. 1, 2014 Dec. 31, 2014	Jan. 1, 2015 Mar. 31, 2015	Apr. 1, 2015 Jun. 30, 2015	Jul. 1, 2015 Sep. 30, 2015	Oct. 1, 2015 Dec. 31, 2015	Jan. 1, 2016 Mar. 31, 2016
project management and planning						M
shale properties, measurements; geochemical		m	M			
shale properties, measurements; adsorption isotherms		m	M			
shale properties, measurements; permeabilities				m		m
water imbibition, redistribution experiments						M
shale properties, model development		m		M		
shale properties, model development and modeling			m			M
water imbibition, redistribution modeling						m

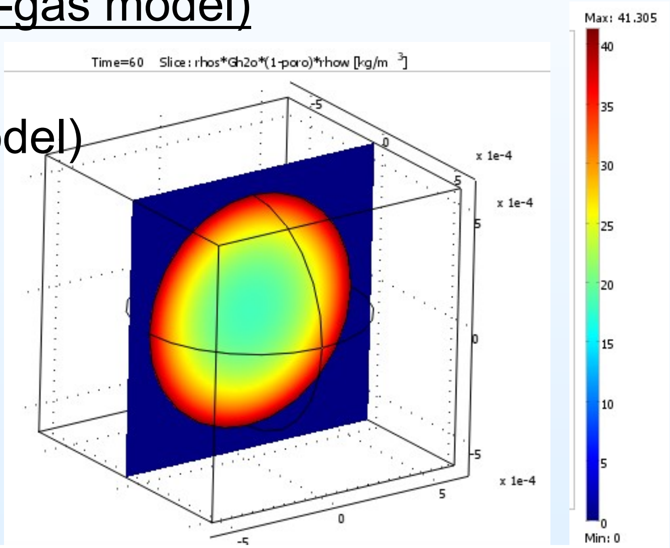
m denotes completion of minor milestone.
M denoted completion of major milestone.

Questions guiding research

- How does shale water saturation (S_w) depend on drainage (desorption) capillary pressure (P_c)?
- How permanent is damage from water-blocking?
- What are threshold water saturations and water activities for gas flow?
- Identify generalizable relations from laboratory tests and modeling, that could be useful in predictions for behavior of reservoirs.

Ongoing and future work: Testing Macroscopic Transport Theories with Adsorption/Desorption Experiments in Shale Rock

- <u>Are the Maxwell-Stefan Diffusion Equations (Dusty-gas model) applicable under partially saturated conditions?</u>



- Maxwell-Stefan Diffusion Equations (Dusty-gas model)

$$-\frac{\nabla p_{\mathrm{H_2O}}}{RT} = \frac{x_{air} N_{\mathrm{H_2O}} - x_{\mathrm{H_2O}} N_{air}}{D_{\mathrm{H_2O-air}}} + \frac{N_{\mathrm{H_2O}}}{D_{\mathrm{H_2O},solid}}$$

$$-\frac{\nabla p_{\mathrm{air}}}{RT} = \frac{x_{\mathrm{H_2O}} N_{\mathrm{air}} - x_{\mathrm{air}} N_{\mathrm{H_2O}}}{D_{air-\mathrm{H_2O}}} + \frac{N_{\mathrm{air}}}{D_{air,solid}}$$

$$D_{\mathrm{air-H_2O}} = D_{\mathrm{H_2O-air}}$$

$D_{\mathrm{air-H_2O}}$: Binary diffusion coefficient
$D_{\mathrm{i-s}}$: Knudsen diffusion coefficient between component i and solid
w_i : Mass fraction of component i
x_i : Mol fraction of component i
p_{i} : Partial pressure of component i
N_{i} : Molar flux of component i
n_{i} : Mass flux of component i

- Mass Balance Equation

$$\frac{\partial}{\partial t}\left[\rho\, w_{\mathrm{H_2O}}\phi + (1-\phi)\,\rho_s G_{s,\mathrm{H_2O}}\rho_w\right] + \nabla . n_{\mathrm{H_2O}} = 0,$$

$$n_{\mathrm{H_2O}} = M_{\mathrm{H_2O}}\, N_{\mathrm{H_2O}}$$