Improved Unconventional Reservoir Stimulation Through Understanding Controls on Fracturing Fluid Imbibition and Water Blocking

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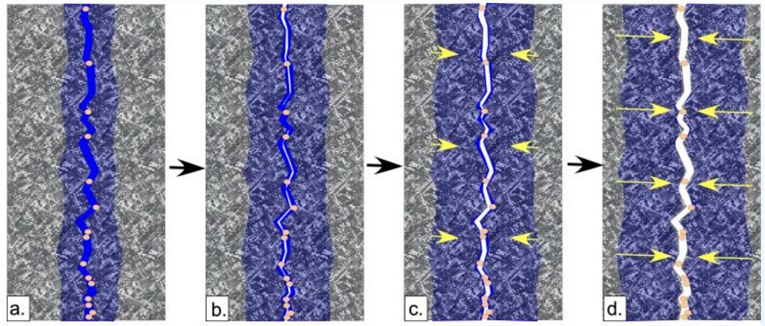
Presentation Outline



- Introduction
  - ✓ Problem statement
  - ✓ Project goals and objectives
- Water blocking issues during hydraulic fracturing
  - ✓ Spontaneous imbibition (water-skin effect)
  - ✓ Controlling factors
- Laboratory studies on water partitioning in shale reservoirs and strategies to mitigate water blocking.
- Practical considerations to reduce water blocking during shut-in period after hydraulic fracturing.

Problems of Water Use in Hydraulic Fracturing

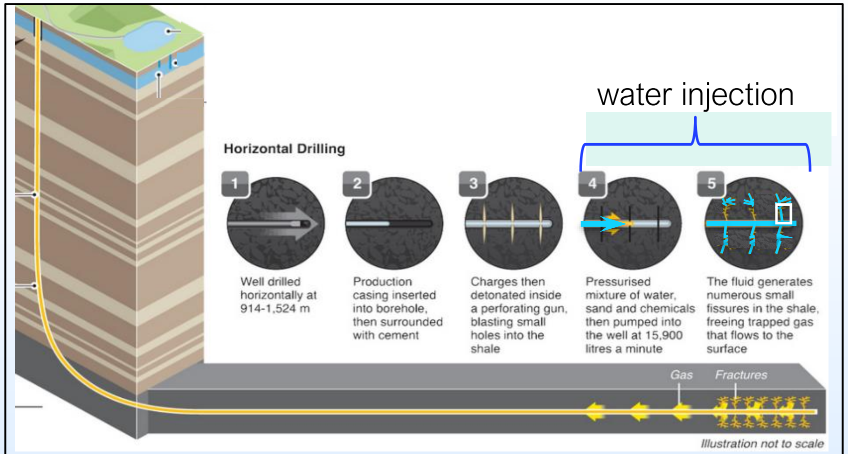
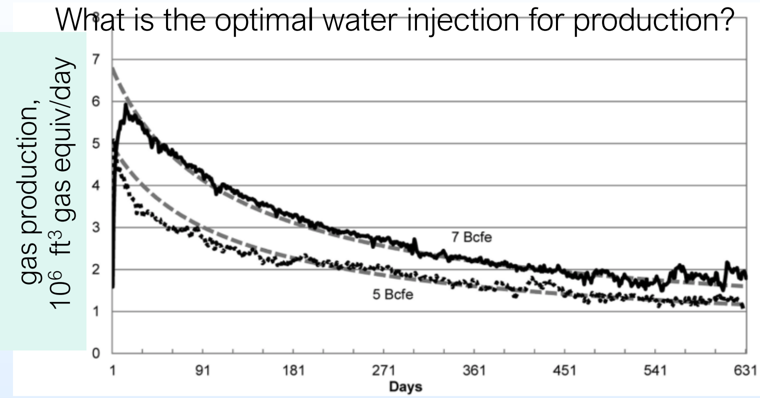


Figure modified from *National Geographic, Chesapeake Energy, EIA, & USGS*



Marcellus Shale wells, Ultra Petroleum, 2012

- 10^6 to 10^7 gallons of water is used per well to hydraulically fracture shale reservoirs.
- Cost of water supply and flow-back water treatment are large ($50K to $1M per well).
- Typically > 70% of injected water remains in the reservoir and restricts counter-current flow of gas back to wells.
- A rational basis to reduce water use can be beneficial.

Problem Statement

- Transport properties controlling water and gas distributions are spatially and directionally variable, and fracture connectivity is complex.

- Actual distributions of matrix and fracture permeabilities will never be known.

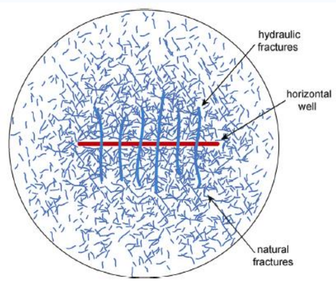
- Improved, physically-based, practical models are needed to optimize water use for efficient hydrocarbon recovery.

Goals and Objectives

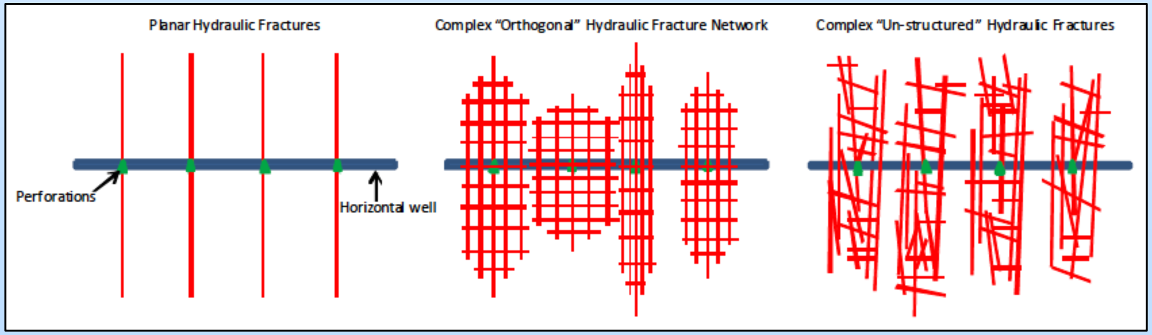
- Improve understanding and predictions of water entry and redistribution in low permeability materials
- Identify the hierarchy of factors controlling water blocking
- Improve simple models of water-gas transport in unconventional reservoirs
- Understand impacts of varying water injection volumes and shut-in times on production

Importance of the (micro)Fracture-Matrix Contact Region

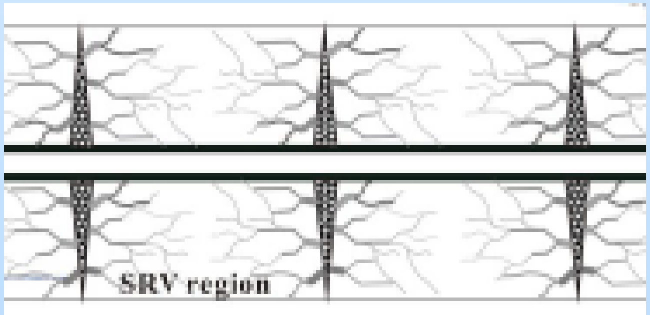
- Simplest models with planar fractures orthogonal to horizontal wells grossly under-represent the fracture-matrix contact area.
- More complex fracture networks improve representation of fracture-matrix contact area.
- However, effective fracture surface area hydraulically contacting matrix rock is largely unknown. Imbibition analyses can provide hydraulic contact areas.



Gu et al., Petrol., 2017



Cipolla et al., SPE146876, 2011

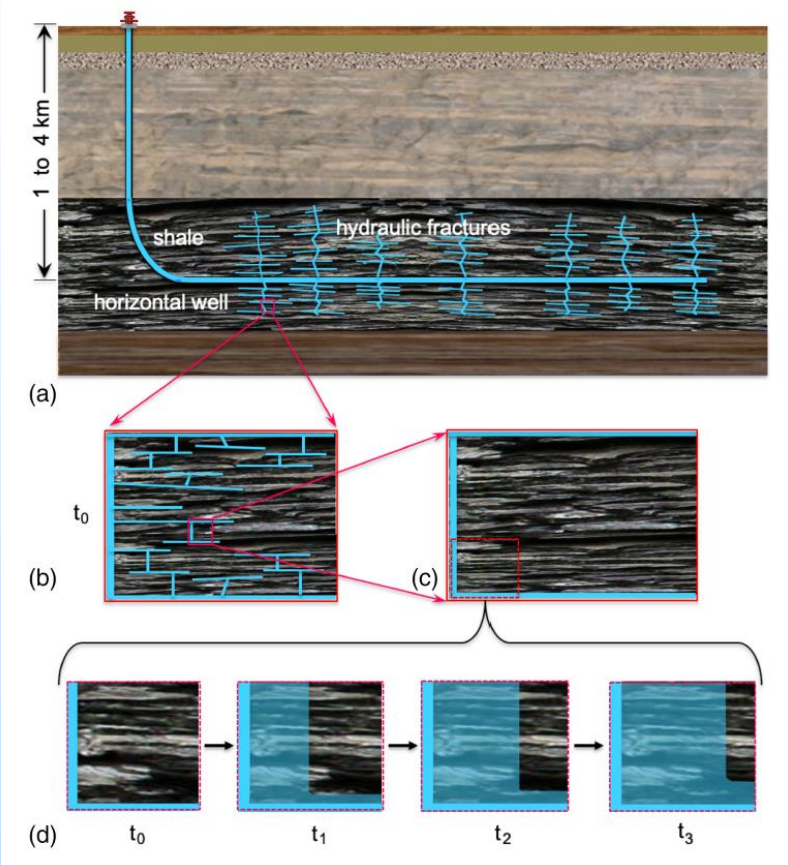


Wang et al., Sci. Reports, 2018

Leakoff and Imbibition of water into shale matrix during hydraulic fracturing is responsible for the large volumes of fluids used and unrecovered

Basic unit: local (micro)fracture-matrix volumes

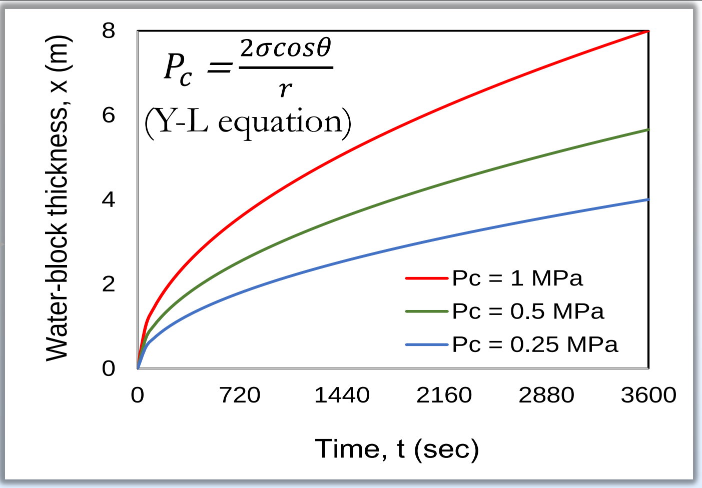
- Can water loss due to imbibition into shale be reliably predicted?
- How does imbibition scale with permeability in hydraulic fracturing?
- Can scaling relations be developed to predict water loss and guide water use in unconventional reservoirs?
- Can improvements be made to directly measure water permeability in shales?



Factors Influencing Spontaneous Imbibition in Shales during Shut-In Period

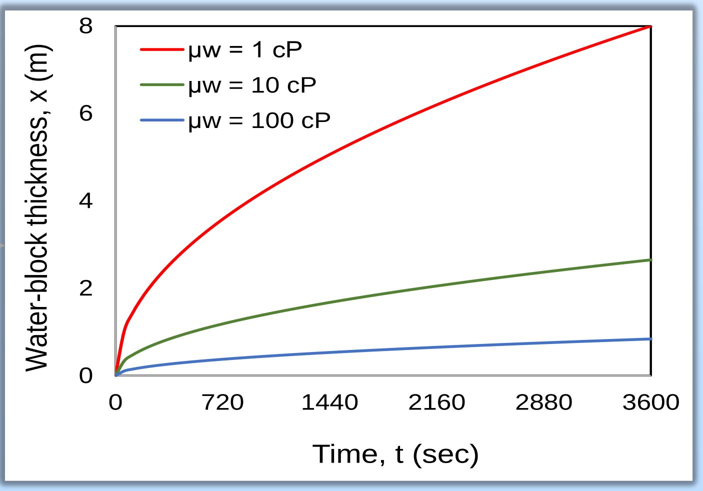
- Formation properties*
  - ✓ Bulk porosity (ϕ) and pore size (r)
  - ✓ Bulk permeability (k)
  - ✓ Initial & wetting front saturations (S_{wf}, S_{wi})
  - ✓ Clay minerals
- Fluid properties*
  - ✓ Interfacial tension‡ (σ)
  - ✓ Wettability‡ (θ)
  - ✓ Viscosity‡ (μ_w, μ_{nw})
  - ✓ Relative permeability (k_{rw}, k_{rnw})
- Shut-in practices (shut-in pressure*‡ and time, t‡)

*Depth dependent ‡Controllable

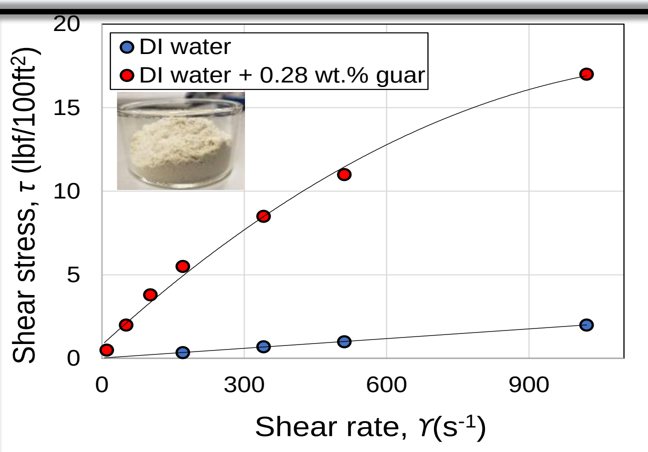


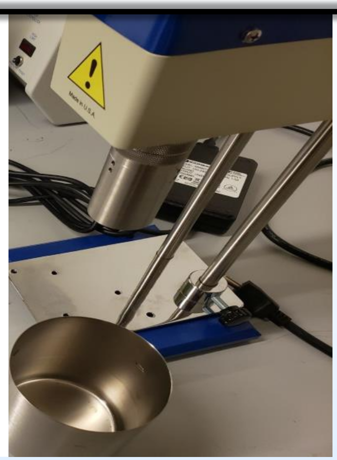
$$x = \sqrt{\frac{2kk_{rw}k_{rnw}P_c}{(k_{rw}\mu_{nw} \pm k_{rnw}\mu_w)(S_{wf}-S_{wi})\phi}}\sqrt{t}$$

(Li & Horne 2006)



Materials: Fluid and Experimental Samples





Apparent viscosity, μ_a at 25°C (cP)	
DI water	1.00
DI water + 0.28 wt.% Xanthan gum	9.25

Interfacial tension, σ at 25°C (mN/m)	
DI water	72.00
DI water + 0.02 wt.% surfactant	58.50
DI water + 0.28 wt.% Xanthan gum	68.00

DI – Deionized

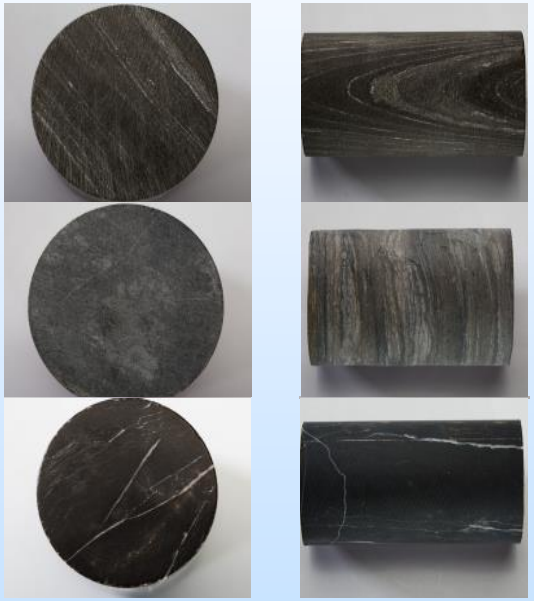
Cross-sectional view

Side view

Eagle Ford shale

Wolfcamp shale

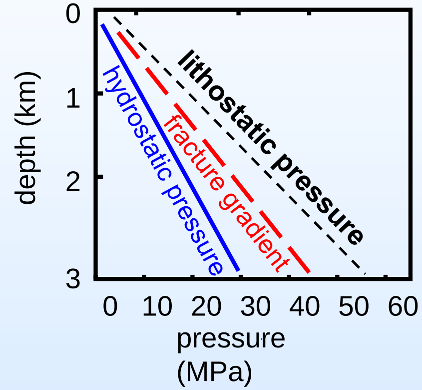
Mancos shale



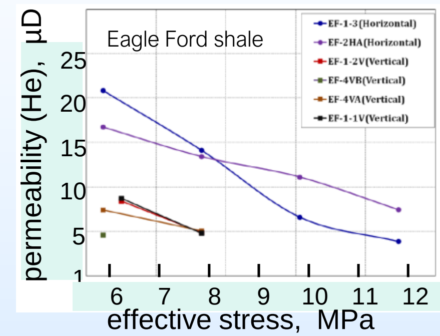
Challenges for Laboratory Water Permeability Measurements on Unconventional Reservoir Samples

- Samples undergo at least 10 MPa of stress relief upon recovery from wells.
- Cores often experience further visible damage during preparation in laboratory.
- Lab *k* values are stress-dependent.
- Gas flow is commonly used, but Knudsen (Klinkenberg) slip corrections needed to obtain true *k* have significant uncertainty.
- Dry gas flow is insensitive to wettability.
- Very low *k* cores are most susceptible to annular (wall) flow artifacts
- The crushed rock gas *k* method destroys the rock matrix, eliminating intergranular flow networks.

stress-release sample damage

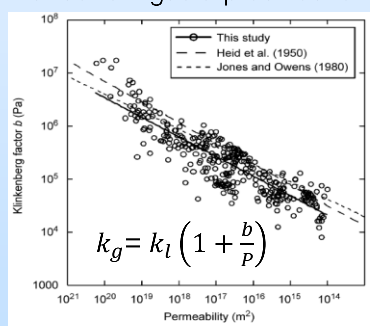


stress-dependence of *k*

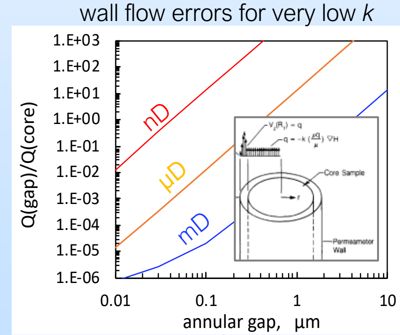


Mokhtari et al., URTeC 1555068, 2013

uncertain gas slip corrections



wall flow errors for very low *k*



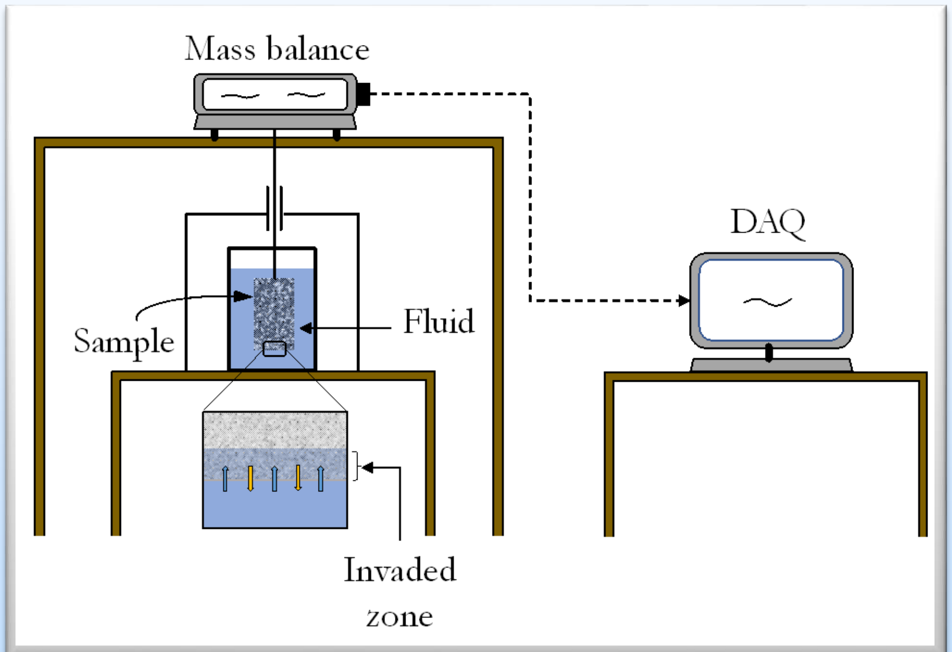
crushed rock method

Tanikawa & Shimamoto, Int. J. Rock Mech. Mining Sci. 2009

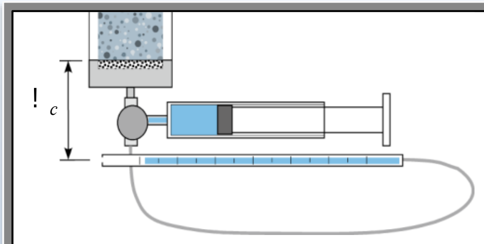
Tokunaga, Soil Sci. Soc. Am. J., 1988

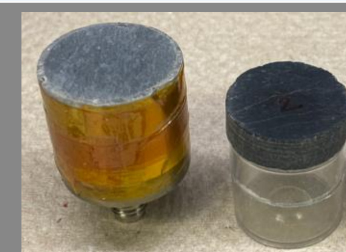
Methods: Spontaneous Imbibition

Method for measuring S and k in μD to mD materials

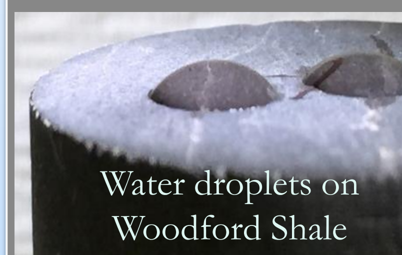


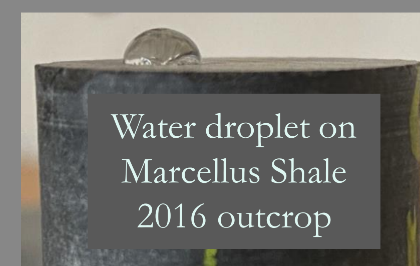
Method for measuring very low S and k in nD to μD materials is developed





Measuring sorptivities at fixed capillary pressure





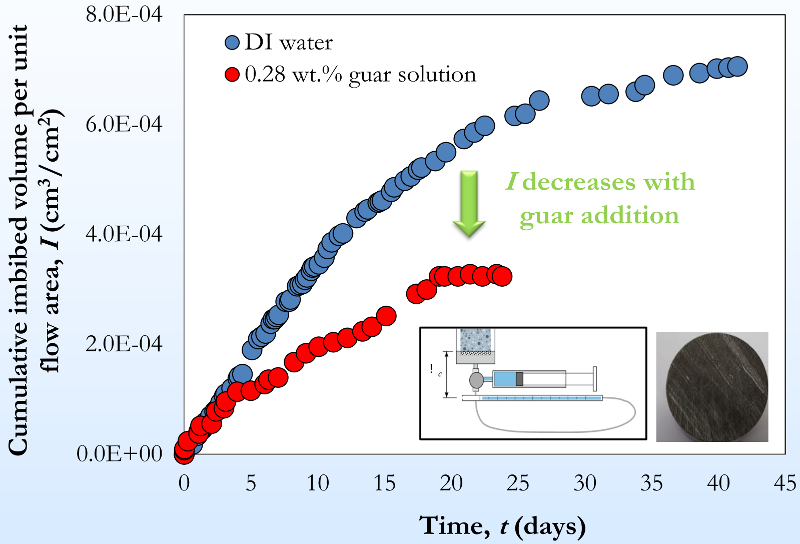
Understanding how to account for wettability influences on water imbibition into shales

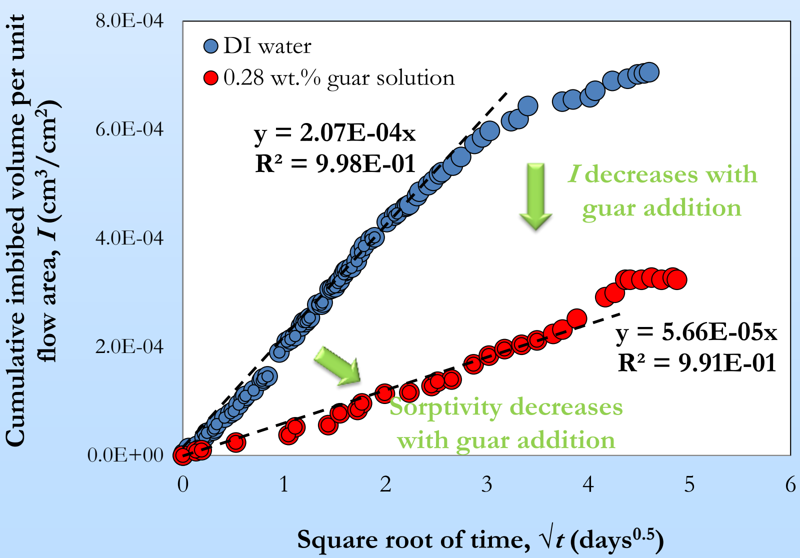
Use of **thickened fluid** may help to minimize water-block effects

Eagle Ford Shale

- With water, cumulative imbibed volume per unit area increases with time during the ~ 40-day test period without stabilizing.
- With guar solution, cumulative imbibed volume increases with time but stabilizes after ~ 20 days.
- Smaller volume of guar solution imbibed the shale matrix than water.
- Sorptivity decreases after guar addition. Adding guar to the base fluid reduced sorptivity (i.e., rate of imbibition) by approximately 73%.

Omosebi et al. (In preparation)



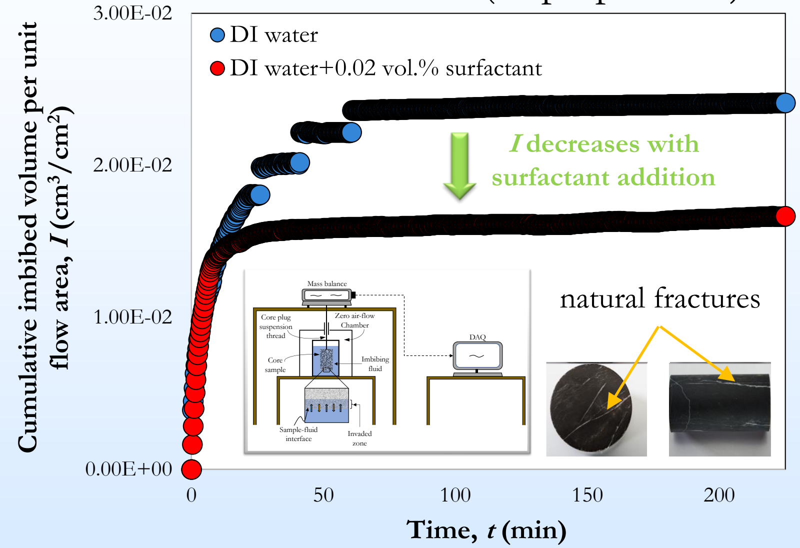


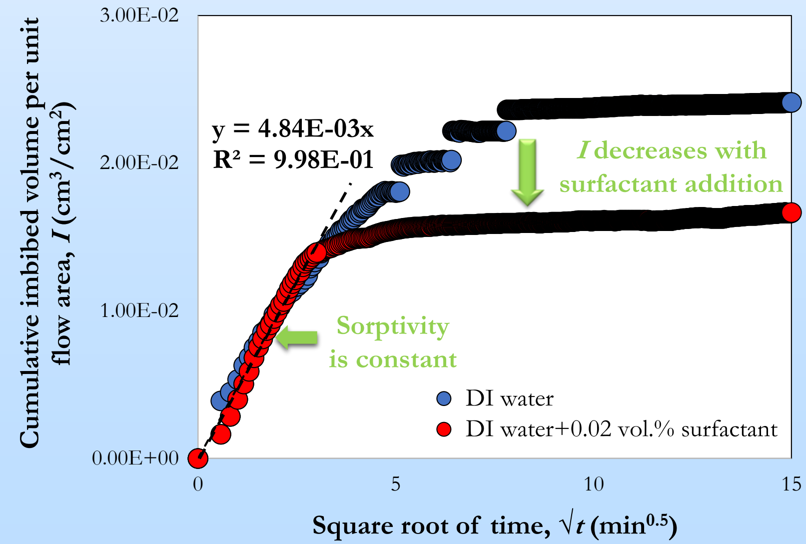
Use of surfactant helps to minimize water-block effects *in lab experiments*

Mancos Shale

- Cumulative imbibed volume of water per unit area is reduced by adding surfactant to the base fluid.
- Sorptivity remains the same after surfactant addition.
- Therefore, addition of surfactant reduces cumulative imbibed volume of fluid, but not imbibition rate.

Omosebi et al. (In preparation)





Imbibition of Water into Porous Media: Need Practical, Physically-based Predictions for Water Imbibition during Shut-In

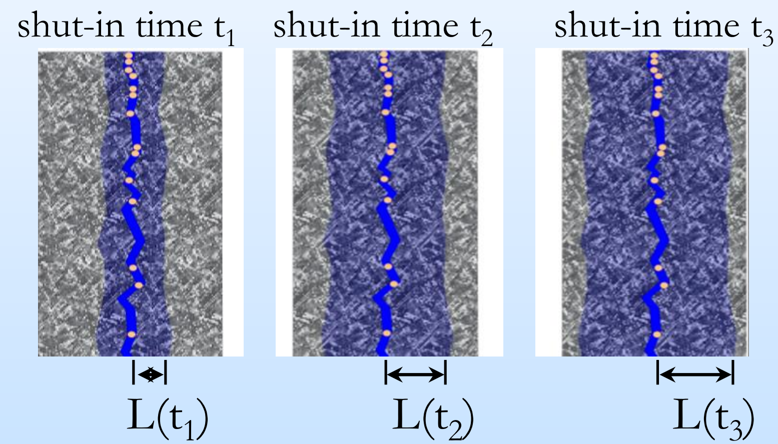
- Bell & Cameron (*J. Phys. Chem.*, 1906) identified the basic physics of water imbibition into porous media. Green & Ampt (1911), Lucas (1918), Washburn (1921), and thousands of others followed.

$$L(t) = \sqrt{\frac{2k}{\mu\Delta\theta}\left(P_{c,f} - P_{c,0}\right)\sqrt{t}}$$

G-A model
(Green & Ampt, 1911)

where **k* is the permeability, μ is the viscosity, $\Delta\theta$ is the change in volumetric water content, *$P_{c,f}$ is the capillary pressure at the advancing wetting front, and $P_{c,0}$ is the capillary pressure at the fracture surface.

$$I(t) = \sqrt{\frac{2\Delta\theta k}{\mu}\left(P_{c,f} - P_{c,0}\right)\sqrt{t}}$$

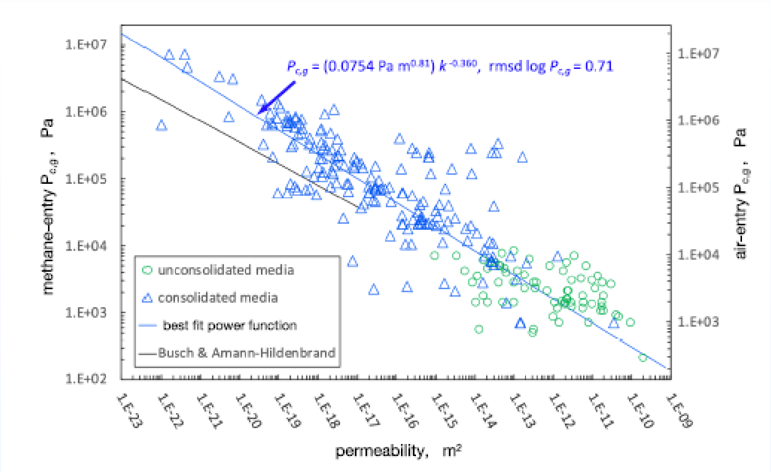


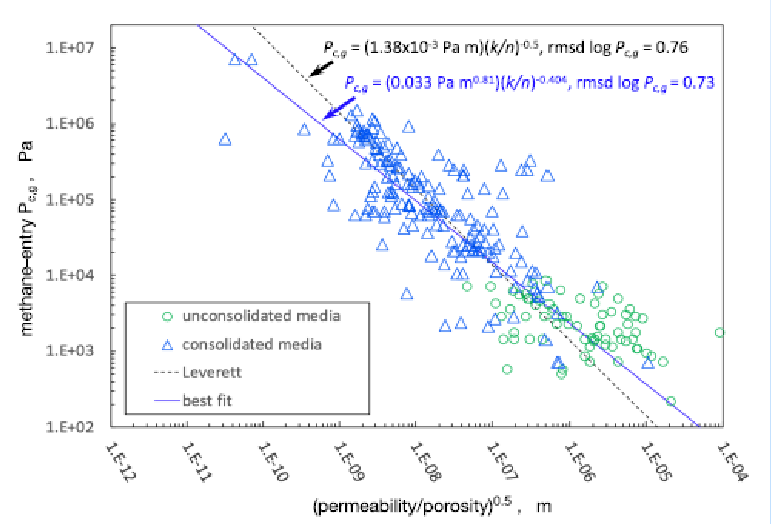
- $P_{c,f}$ is quantified through: $P_{c,f} = \int_0^{P_{c,u}} k_r dP_c$

* Two parameters with highest uncertainty are multiplied.

Correlation Between Matrix k *and* $P_{c,f}$

- To develop predictions of imbibition that are simpler than the original G-A model, the correlation between $P_{c,g}$ and k is first determined.
- Literature data were assembled to determine correlation between $P_{c,g}$ and $P_{c,f}$. Data (including our shale measurements) indicate that $P_{c,g} \sim (0.075\ Pa\ m^{0.72}) * k^{-0.36}$ over a wide range of k and ϕ. Available data show that $P_{c,f} \sim 1.21 * P_{c,g}$
- This allows determination of the desired $P_{c,f}$ - k correlation: $P_{c,f} \sim (0.091\ Pa\ m^{0.72}) * k^{-0.36}$.





Tokunaga, T.K. 2020. Simplified Green-Ampt model, imbibition-based estimates of permeability, and implications for leak-off in hydraulic fracturing. *Water Resour. Res.*, 56.

Predicting Wetting Front Advance, Cumulative Imbibition, & Permeability based on Sorptivity Measurements

- Imbibition distance:

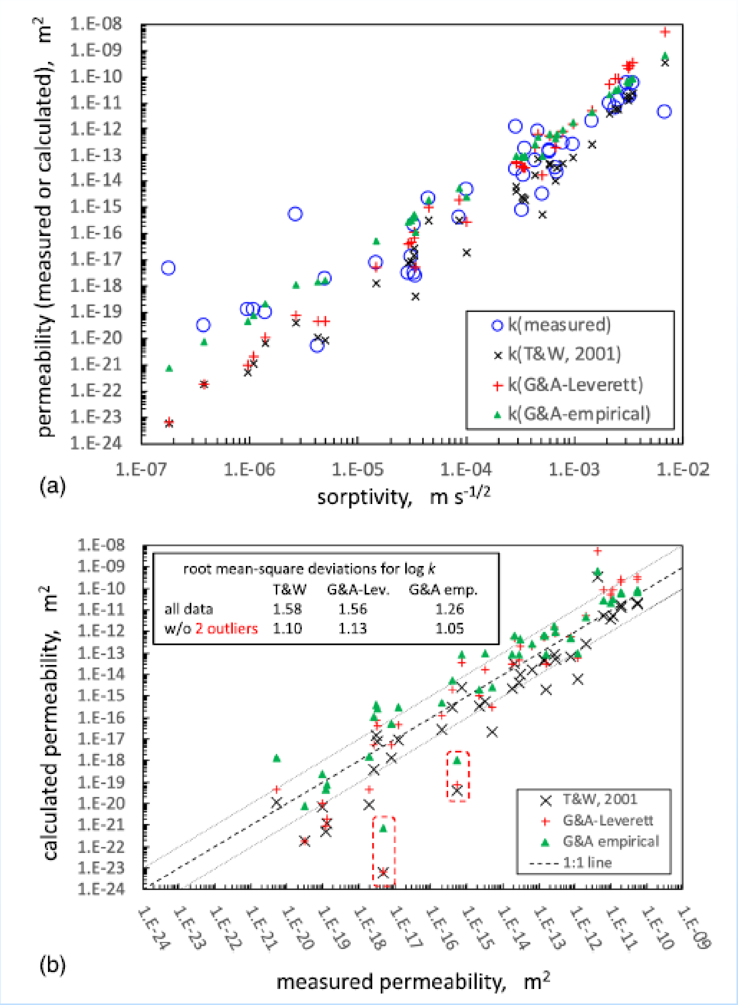
$$L(t) = \sqrt{\frac{0.182*(1-b)}{\mu*\Delta\theta}\,\boldsymbol{k^{0.32}}\sqrt{t}} \sim \sqrt{\frac{0.182*(1-b)}{\mu*\Delta\theta}}\,\sqrt[3]{\boldsymbol{k}} * \sqrt{t}$$

$$I(t) \sim \sqrt{\frac{0.182*\Delta\theta*(1-b)}{\mu}}\,\sqrt[3]{\boldsymbol{k}} * \sqrt{t} = S\sqrt{t}$$

$$k \sim S^3\left(\frac{\mu}{0.182*\Delta\theta*(1-b)}\right)^{\frac{3}{2}}$$

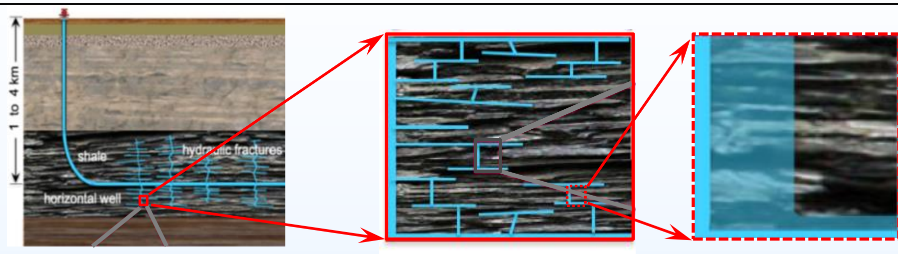
- To test *S*-based predictions of *k*, literature values of *k* and *S* were compiled from sources where both parameters were experimentally determined on the same materials.

* Uncertainty reduced to a single parameter, *k*

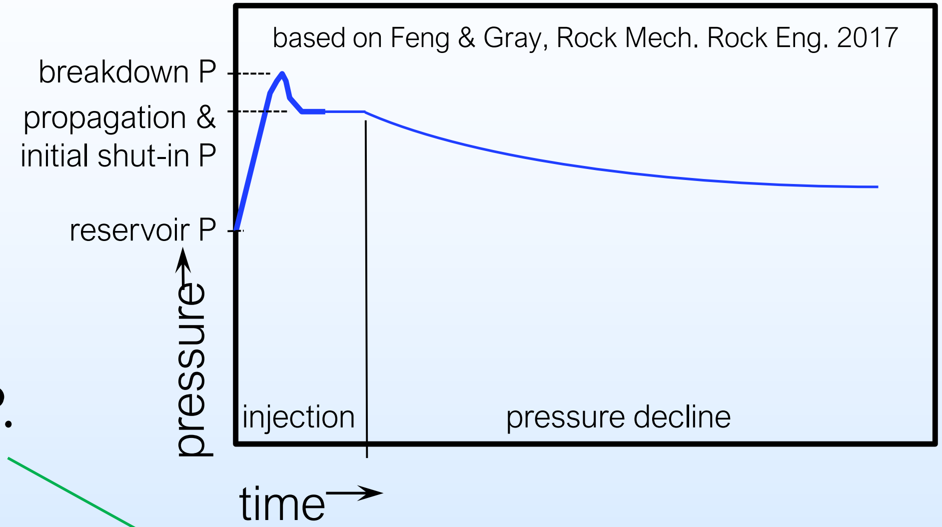


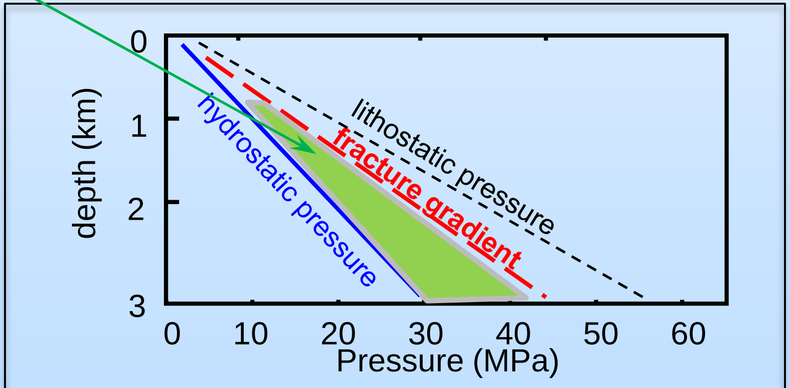
Tokunaga, T.K. 2020. Simplified Green-Ampt model, imbibition-based estimates of permeability, and implications for leak-off in hydraulic fracturing. *Water Resour. Res.*, 56.

Driving Force for Imbibition: Dominance of Shut-In Pressure



- $P_{c,0}$ is constrained to values between the depth-dependent breakdown P and hydrostatic P.
- $|P_{c,0}|$ at fracture-matrix interfaces are very large because they must exceed hydrostatic P. At 2 km depth, shut-in $P_{c,0} \approx$ -30 MPa.





modified from:
http://www.glossary.oilfield.slb.com/en/Terms.aspx?LookIn=term%20name&filter=pressure%20gradient

k (m^2)	$P_{c,f} \sim 0.091 * k^{-0.36}$ (MPa)	$\lvert P_{c,0}\rvert / P_{c,f}$
10^{-21}	3.30	9.1
10^{-17}	0.12	250

Water imbibition dependence on permeability and time

- Given that $|P_{c,0}| >> P_{c,f}$ during hydraulic fracturing,

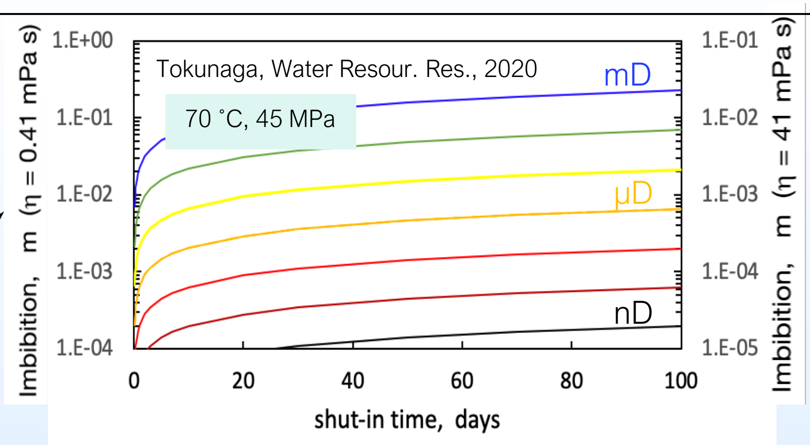
$$L(t) \sim \sqrt{\frac{0.182*(1-P_{c,0}/P_{c,f})}{\mu*\Delta\theta}}\sqrt[3]{k}*\sqrt{t}$$

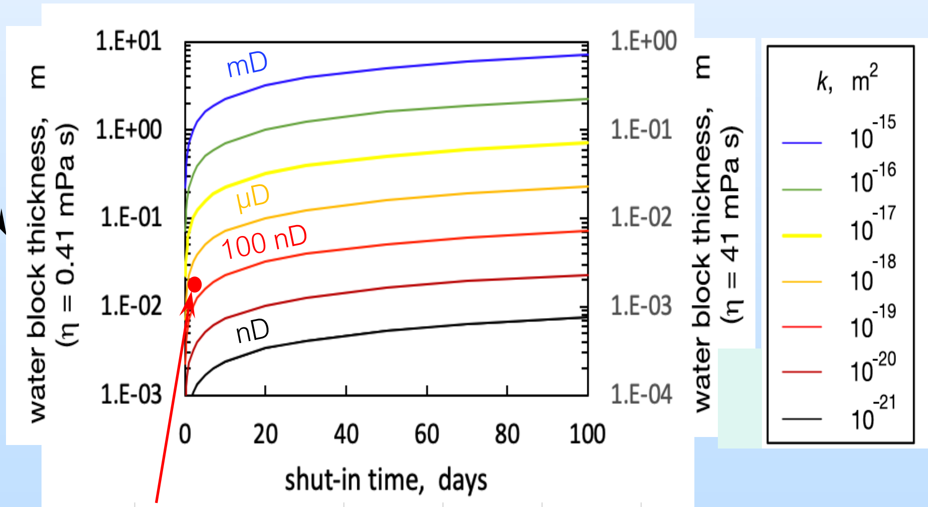
- Water volume/(entry fracture area) is less than 1 cm into low k ($\leq$ 1 µDarcy) shale matrix, for shut-in times up to a month.

- Water blocks in low k ($\leq$ 1 µDarcy) shale are only centimeters thick for shut-in times up to a month but impede hydrocarbon recovery.

- Fracture-microfracture networks have very large interconnected areas, > 100 hectare/well!

- Minimizing shut-in times reduces water block thicknesses and precipitation along fractures, hence can improve production.





100 nD shale, day 1, at greater P, from Moridis, SPE-185512, 2017.

Tokunaga, T.K. 2020. Simplified Green-Ampt model, imbibition-based estimates of permeability, and implications for leak-off in hydraulic fracturing. *Water Resour. Res.*, 56.

Depth-dependence of Imbibition Characteristics during Shut-In Period

- Recall:

  $P_{c,f}\,(0,k) \sim (0.091\ Pa\ m^{0.72}) * k^{-0.36}$(ground surface)

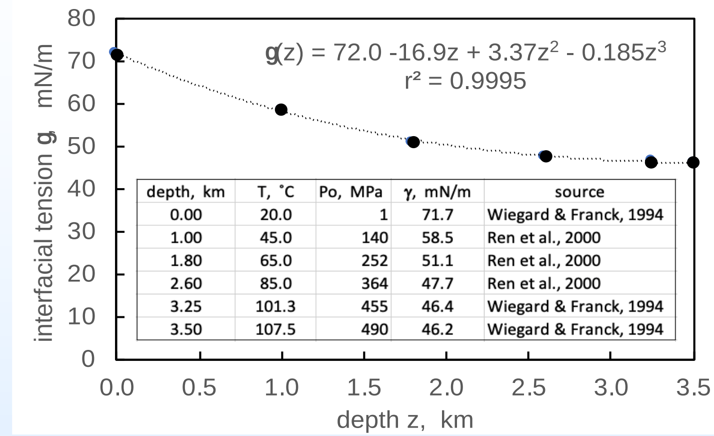
- Depth-dependent IFT used to scale $P_{c,f}\,(0,k)$:

$$P_{c,f}\,(z,k) = \frac{\gamma(z)}{\gamma(0)} * P_{c,f}\,(0,k)$$

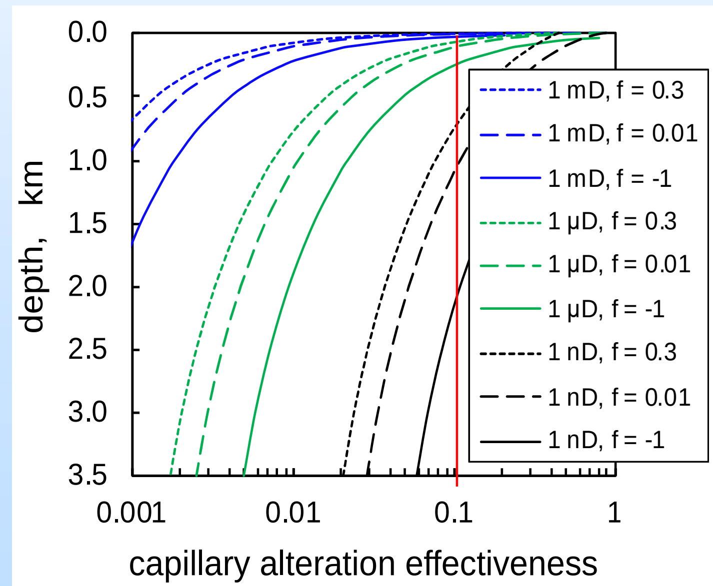
- Depth-dependent water imbibition:

$$I(t) = \sqrt{\frac{2\Delta\theta k}{\mu}\left(f * \frac{\gamma(z)}{\gamma(0)} P_{c,f}\,(0,k) + B * z\right)}\sqrt{t}$$

- Because B*z >> $P_{c,f}$, surfactants are not effective for minimizing imbibition in reservoirs, contrary to claims made in many other studies.



depth, km	T, ˚C	Po, MPa	γ, mN/m	source
0.00	20.0	1	71.7	Wiegard & Franck, 1994
1.00	45.0	140	58.5	Ren et al., 2000
1.80	65.0	252	51.1	Ren et al., 2000
2.60	85.0	364	47.7	Ren et al., 2000
3.25	101.3	455	46.4	Wiegard & Franck, 1994
3.50	107.5	490	46.2	Wiegard & Franck, 1994



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Summary

- Developed practical relations for predicting imbibition characteristics and water permeability in nano-Darcy (shale) materials.
- Constrained shut-in wetting front distances to cm scale into shale matrix.
- Surfactant and thickened fluid evaluated at surface conditions reduced imbibed fluid volume into shale matrix.
- High shut-in pressures in deep reservoirs make reduction of imbibition with surfactants ineffective.
- Recommend short shut-in times and reduced shut-in pressures as practical options to minimize water loss.

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Thank you!

Lessons Learned

– Research gaps/challenges.

- Experimental basis for reliably predicting immiscible fluid displacements over a wide range of matrix permeabilities and wettabilities.

– Unanticipated research difficulties.

- Limited access to the lab due to restrictions imposed by the Covid pandemic
- Fragile core samples. Questionable ability to re-establish in-situ conditions for experiments on cores recovered from deep reservoirs

– Changes implemented in experimental designs.

- Experiments on other more competent porous media (geologic and synthetic) spanning the desired wide ranges in permeability and porosity needed to develop reliable scaling predictions for multiphase flow in tight rocks.

Synergy Opportunities

- Synergies with other Fundamental Shales studies on hydraulic fracture fluids interactions with shale being conducted at LBNL, SLAC, LANL, and Sandia.
- Synergies with other DOE research programs: Investigations of mineral surface chemistry influences on wetting over a wide range of capillary pressures under DOE-BES.
- We are open to developing collaborations with other groups interested in multiphase flow in shales, particularly at complementary scales.

Project Summary, Accomplishments

- Quantified water loss characteristics in unconventional shale reservoir rocks.
- Developed novel, reduced-order, and reduced uncertainty model for predicting imbibition of fracturing fluids in shale reservoirs during shut-in period.
- Showed that high shut-in pressures in deep reservoirs make surfactants ineffective for reducing imbibition.
- 7 publications

Appendix

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

Benefit 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 benefits statement.

This research project is developing basic understanding of water partitioning in hydraulically fractured reservoirs, in order to reduce water use and enhance hydrocarbon recovery.

Project Overview

Goals and Objectives

- Experimentally supported understand of the coupling between water imbibition and gas flow in shales in order to help identify approaches to improving production.
- Develop analytical and numerical relations that will be useful for optimizing water use in hydraulic fracturing.
- Quantifiable metrics: Experiments and analyses span orders of magnitude in permeabilities and flow rates, yielding improved predictive capabilities.

Research Outline

1. Generalizing results on matrix-fracture controls on water loss

- Hydraulic scaling of depth-dependent water imbibition at the local fracture-matrix scale

2. Shale matrix studies

- Imbibition rates: dependence on permeability, porosity, viscosity, wettability.

Research Plan, Original

1. Matrix studies
- Imbibition rates: permeability, porosity, viscosity, wettability
- Gas breakthrough across water blocks: permeability, porosity, viscosity, wettability, and prior imbibition time (shut-in time)

2. Fracture studies
- Drainage rates: fracture aperture, roughness, wettability, and fluid viscosity

3. Generalizing results on matrix-fracture controls on water loss
- Hydraulic scaling of water imbibition at the local fracture-matrix scale
- Hydraulic scaling of fracture drainage
- Integrated predictions for matrix-fracture controls at the well scale

Research Plan, revised order

2. Matrix studies

- Imbibition rates: permeability, porosity, viscosity, wettability

1. Generalizing results on matrix-fracture controls on water loss

- Hydraulic scaling of water imbibition at the local fracture-matrix scale
- Hydraulic scaling of fracture drainage
- Integrated predictions for matrix-fracture controls at the well scale

Organization Chart

- Tetsu K. Tokunaga
  - Senior Scientist (PI), capillary scaling, experimental design
- Omotayo Omosebi
  - Research Scientist, modeling and experiments
- Jiamin Wan
  - Staff scientist, microfluidics, project management

Gantt Chart

	FY2019 Budget Period				FY2020 Budget Period				FY2021 Budget Period			
quarter	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
start date	10/1/18	1/1/19	4/1/19	7/1/19	10/1/19	1/1/20	4/1/20	7/1/20	10/1/20	1/1/21	4/1/21	7/1/21
end date	12/31/18	3/31/19	6/30/19	9/30/19	12/31/19	3/31/20	6/30/20	9/30/20	12/31/20	3/31/21	6/30/21	9/30/21
project management and planning												
annual review				M				M				M
postdoctoral researcher search	m	M										
analyses, modeling												
permeability-imbibition scaling	m	m	m	m	m	M						
on surfactants for reducing imbibition								m	m	m	M	
matrix studies, experimental												
shale measurements; saturation-Pc, imbibition,	m	m	m	m	m	m	m	m	m	m	m	M
fracture-matrix experiments												
micromodel design and experiments	m	m	m	m	m	discontinued due to Covid-limited lab access and departure of assistant						
fracture drainage experiments						Not initiated due to Covid-limited lab access						

notation

m minor milestone

M Major milestone (completion, publication)

Acknowledgments

- NETL Fundamental Shales Program: Stephen Henry, Elena Melchert, Yinka Ogunsola

- Oklahoma Geological Survey, Brian Cardott: (Woodford Shale)

- MSEEL (Marcellus Shale)