Applied Geoscience Conference

Multi-Phase Fluid Imbibition, Distribution, and Wettability in Shale through Synchrotron-Based Dynamic Micro-CT Imaging

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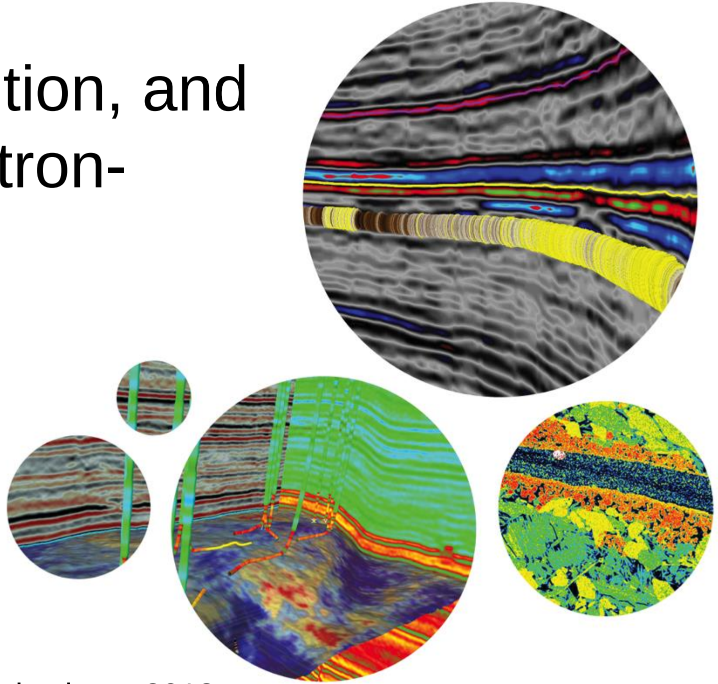


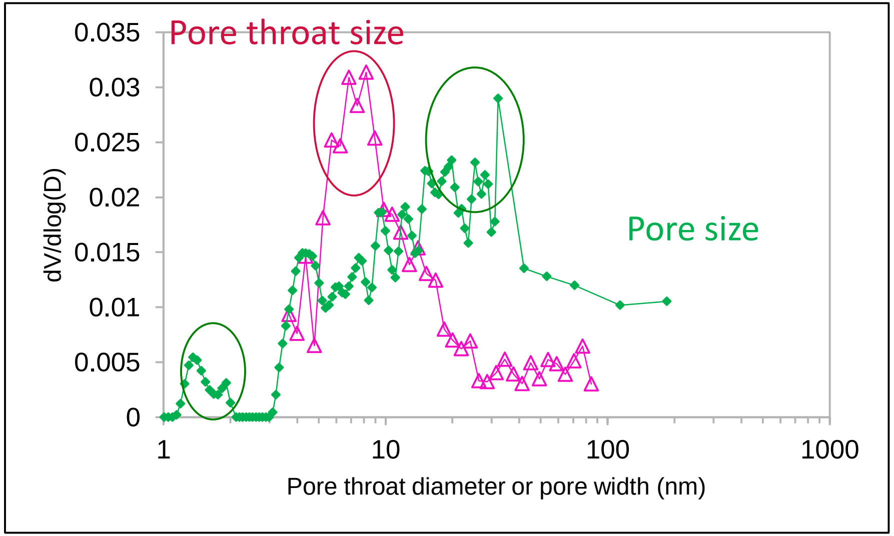
Integrated Approaches of Unconventional Reservoir Assessment and Optimization – 2018

Why we need digital rock physics?

- To predict flow properties
  - Permeability
  - Relative permeability
  - Very hard to get otherwise
- To reveal pore- to micro-scale details
  - Pore structure
  - Flow processes and fundamentals

Digital rock physics for shale

- Very challenging

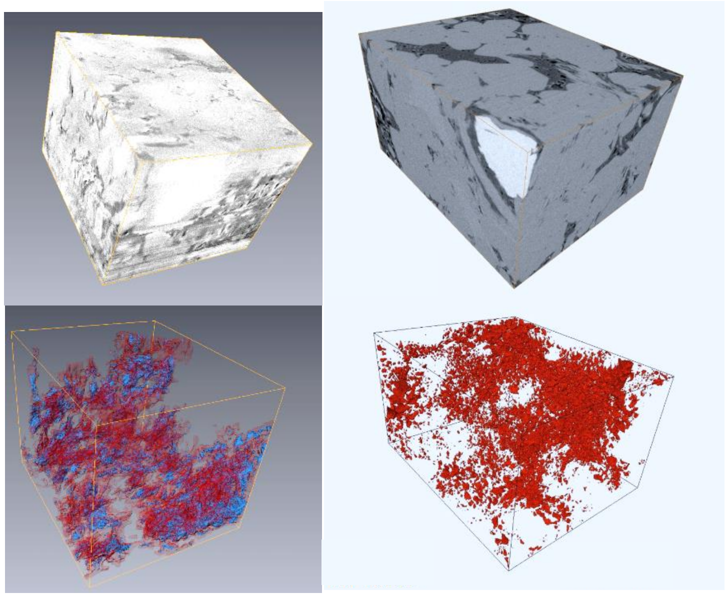


Peng et al., 2017

- Small pore size
  - 20-50 nm
  - N_2 adsorption
- Even smaller pore throats
  - 5-10 nm
  - MICP

Very high resolution is needed to resolve pores in shale

- FIB/SEM
  - 5-10 nm image resolution
  - ≥10 nm milling resolution
  - Only locally-connected pore-networks can be obtained
  - Acquired volume
    - ~10×10×10 μm^3



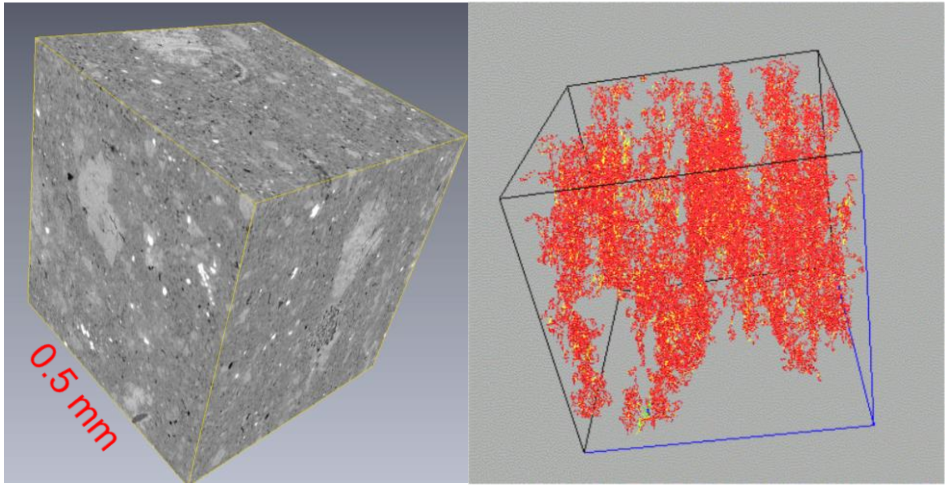
Peng et al., 2015 *Curtis et al., 2011*

Representativeness and up-scaling

- Small pore networks need to be evaluated within a larger framework
- Basic “representative” unit for flow: mm-scale

Micro-CT image

Network of low-density-features



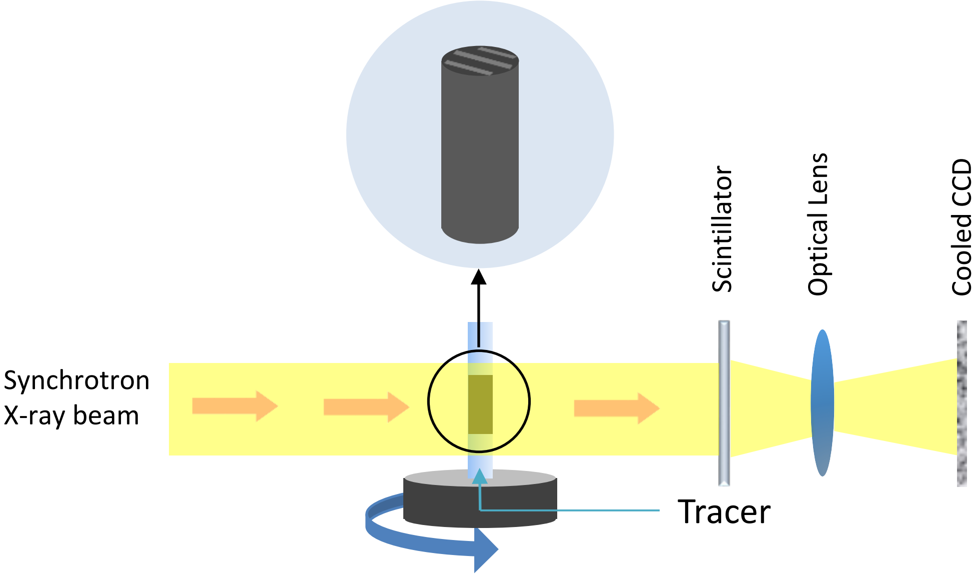
Peng et al., 2015

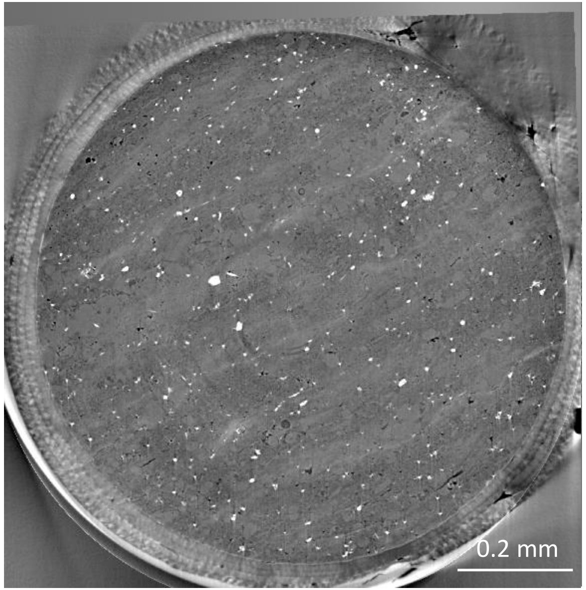
Fluid flow in shale

- A lot of uncertainties and unknowns
  - How hydrocarbon moves from pores in matrix to production wells?
  - How much matrix contributes? In what pattern, uniformly?
  - What’s fracture-matrix interaction?
  - Wettability: clay more hydrophilic? Organic matter more hydrophobic?
- Digital rock and fluid
  - Direct visualization of fluid flow

A technique of tracer + micro-CT imaging

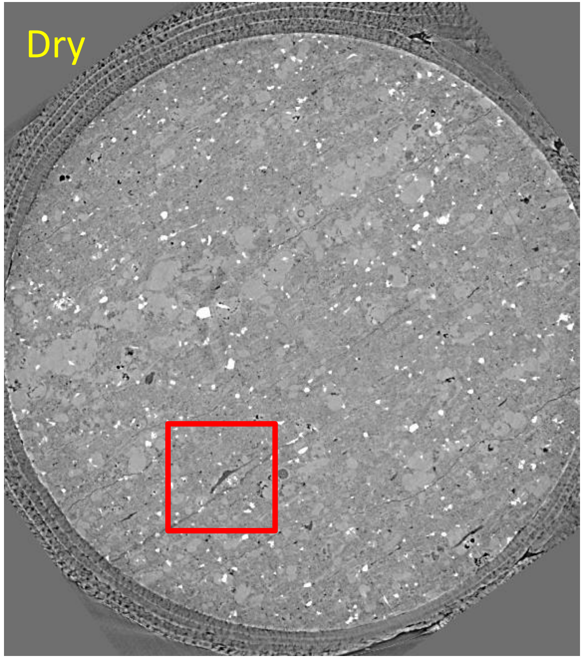
- Diiodomethane: an oil-phase tracer

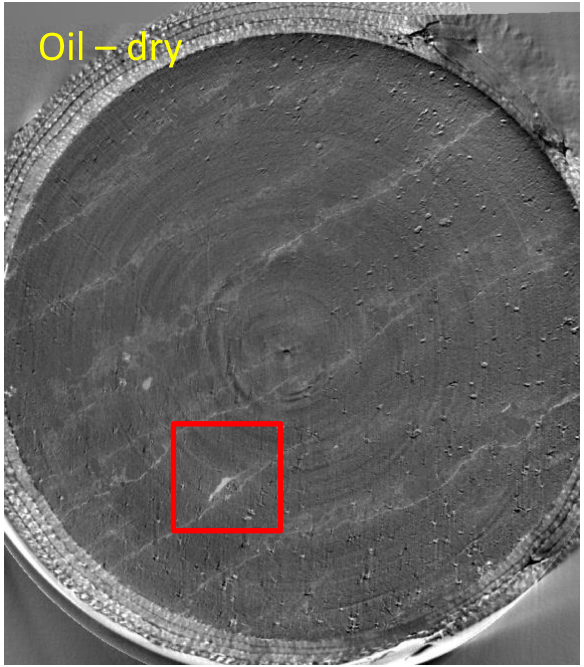




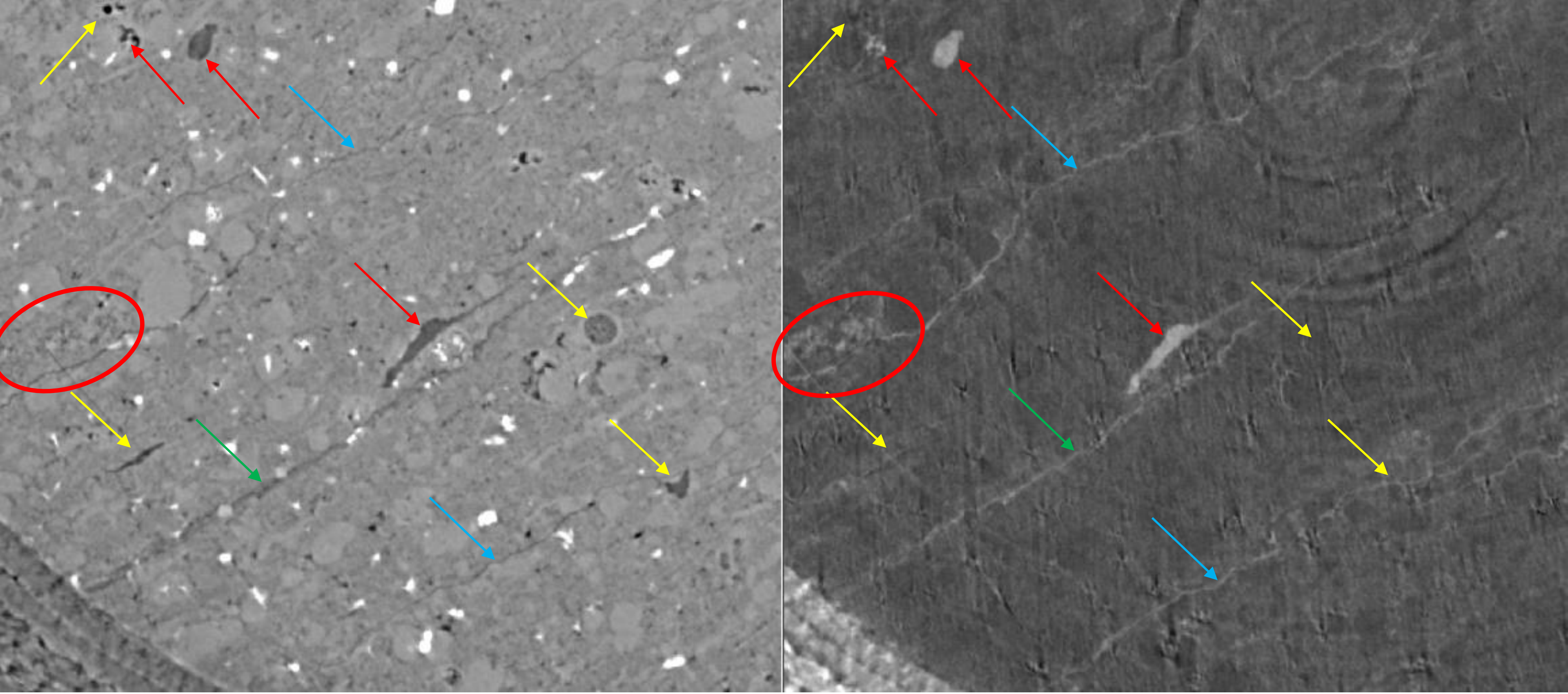
Peng and Xiao, 2017

Sub-mm-scale oil distribution





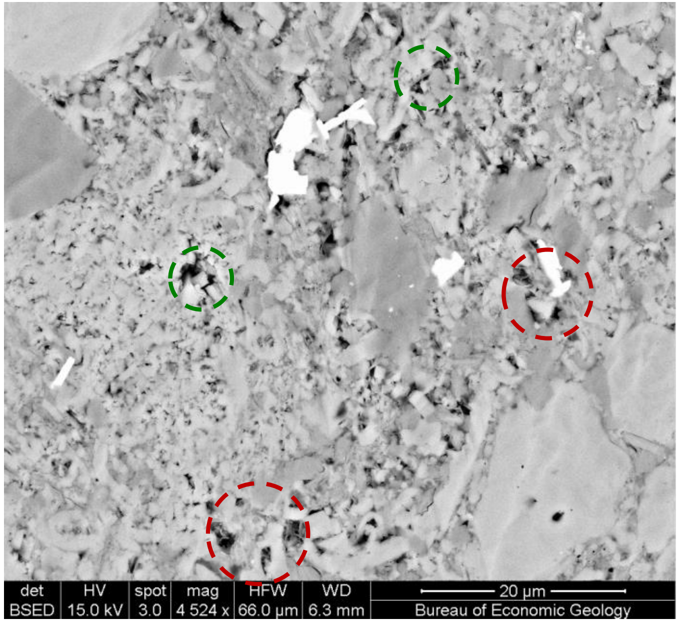
- Brighter areas:
  - Higher oil saturation/abundance
  - Pores with imbibition are accessible, and
  - Oil-wet



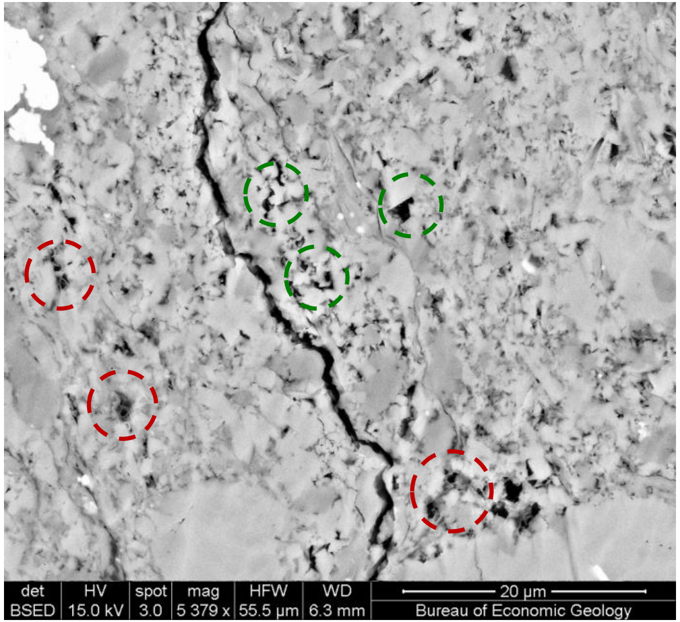
- Fractures
  - In organic matter layer
  - With mineral or mixed “wall” (clay minrals)
  - Overall oil-wet
- Pores
  - In organic matter
  - Not all organic matters are involved (no connection or no pores)
  - Mineral pores, can be oil-wet

SEM images

Pores between large grains



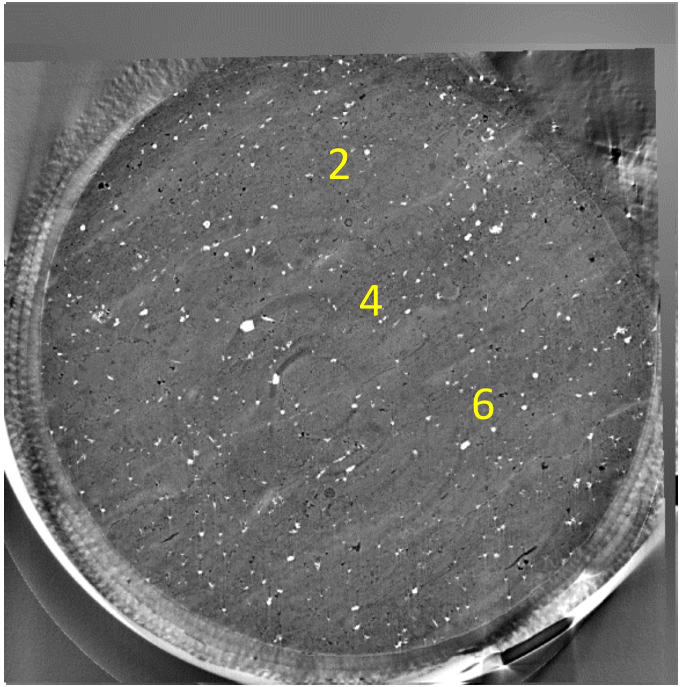
Pores adjacent to micro-fractures



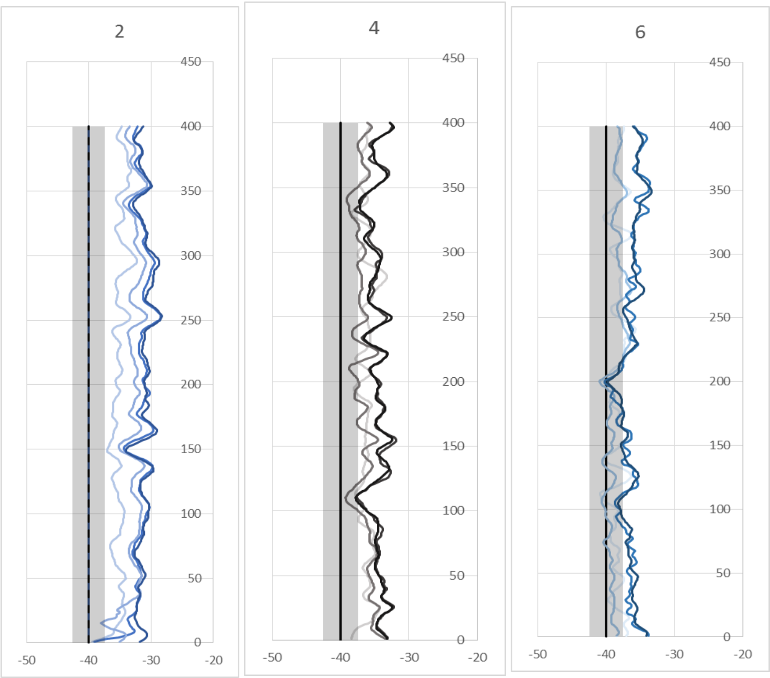
- Include both mineral and organic matter pores
- Oil-wet

How far the oil goes into the matrix?

T = 0.5 h vs. 3 h

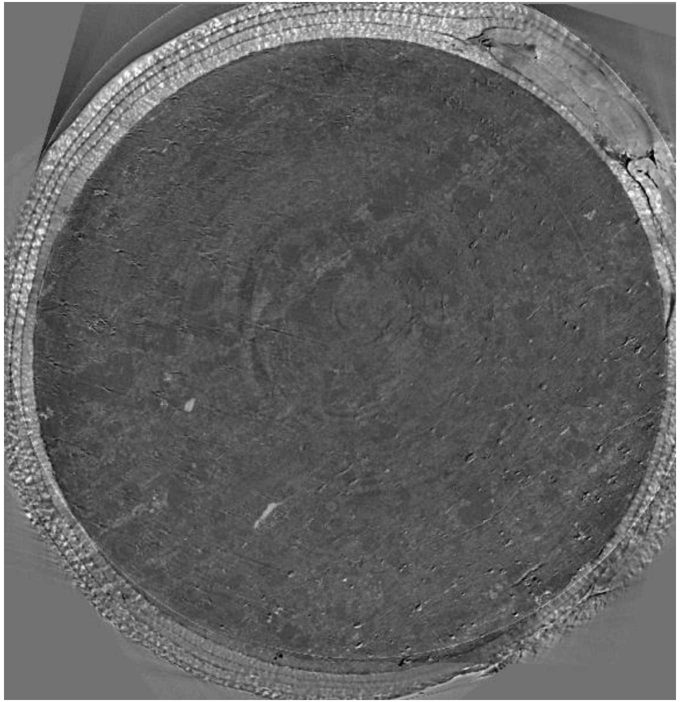


T = 0.5, 1, 2, 3 h, lighter to darker colors

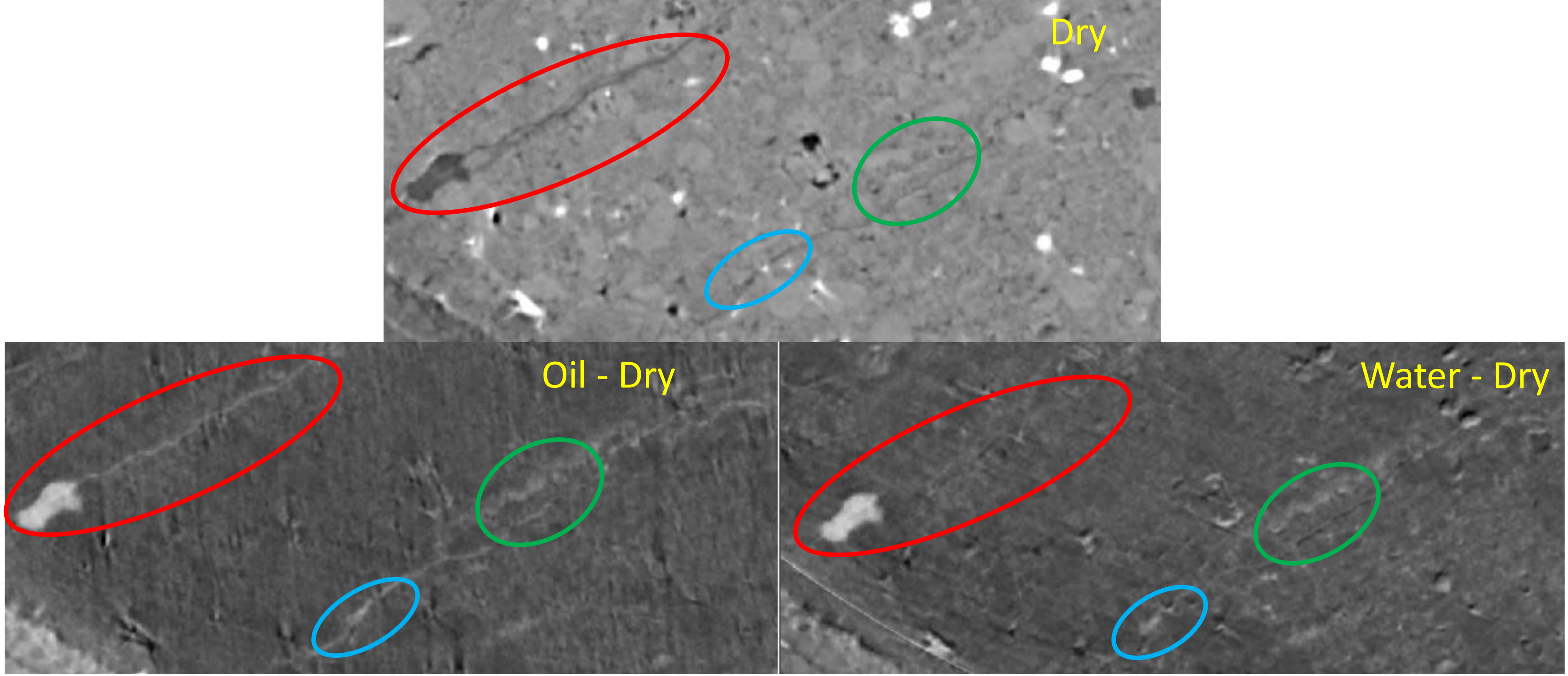


- Imbibition not uniform
- No trend of gradual change along the depth

Water imbibition in oil-imbibed sample

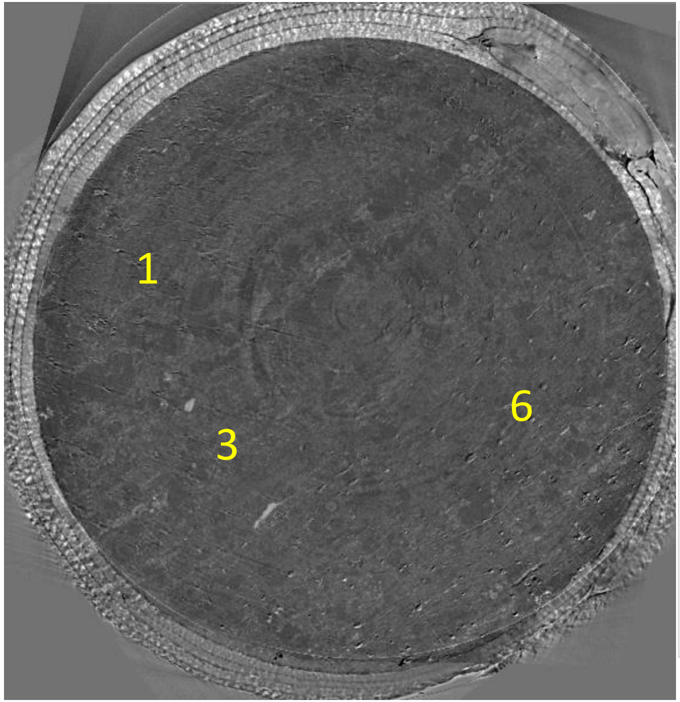


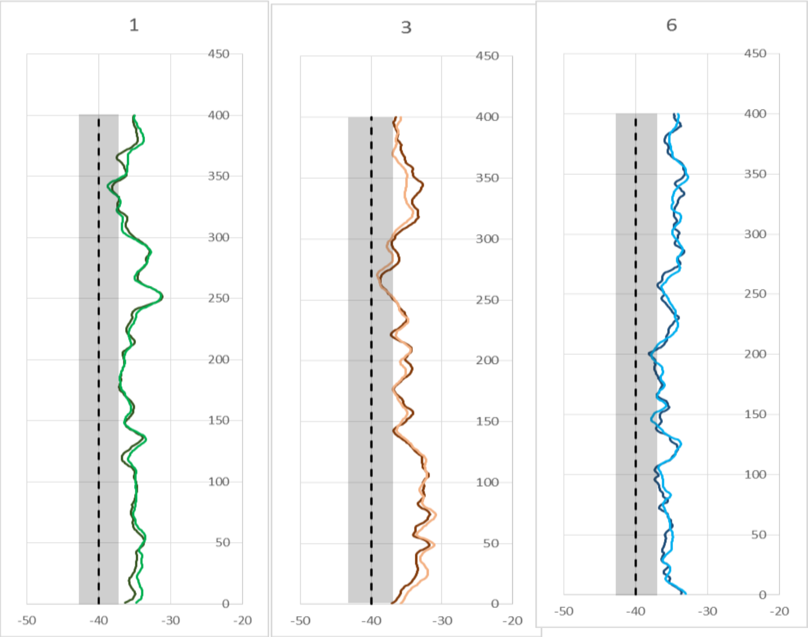
- Oil in fractures was replaced by water
  - Fractures (either w/ organic or mineral wall): more water wet than oil-wet
  - CA_ oil = 46.2±0.62˚; CA_water = 81.5±2.7˚ (Sessile drop method)
  - Contradictory
- Oil in matrix: no obvious change



- Not just wettability
  - Oil displaced in OM fracture, but retained in nearby OM pores
- Residual oil in fracture
  - Wettability and surface conditions (roughness) are complicated

Water imbibition in the matrix of the oil-imbibed sample

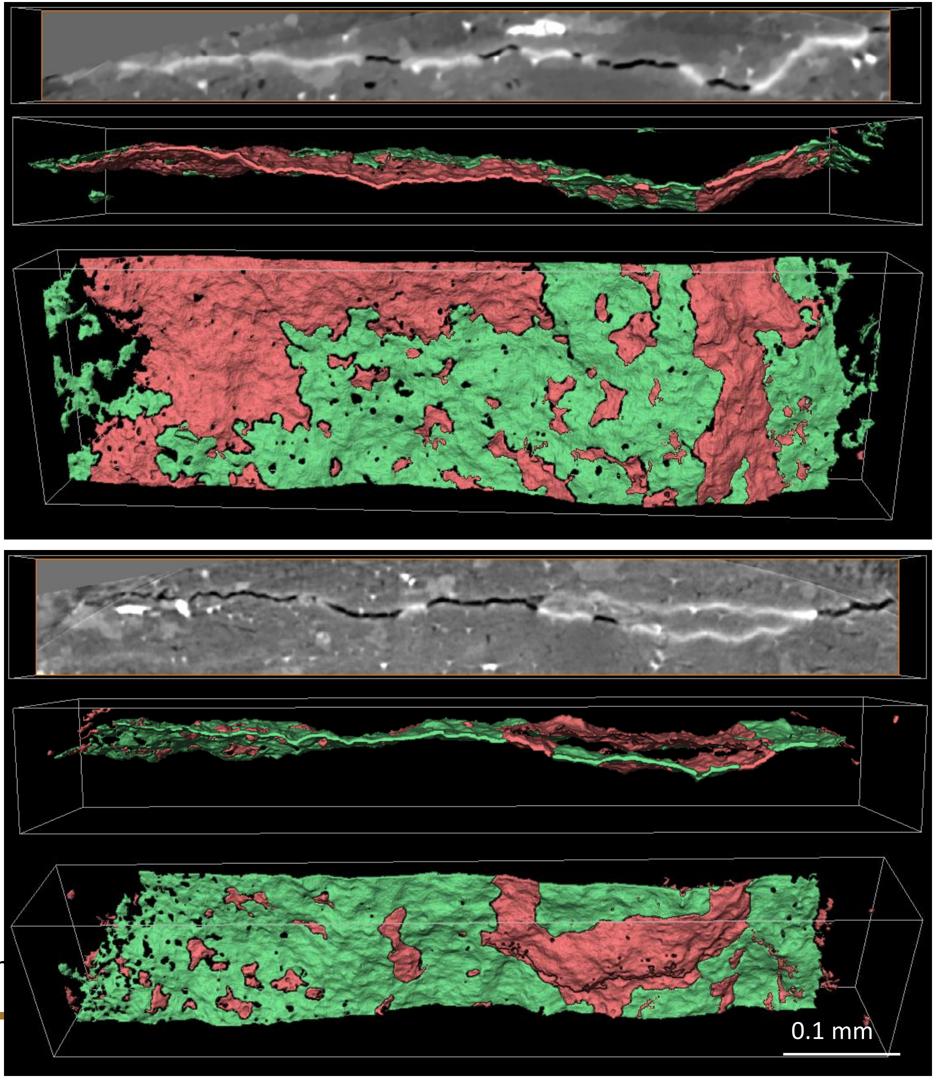




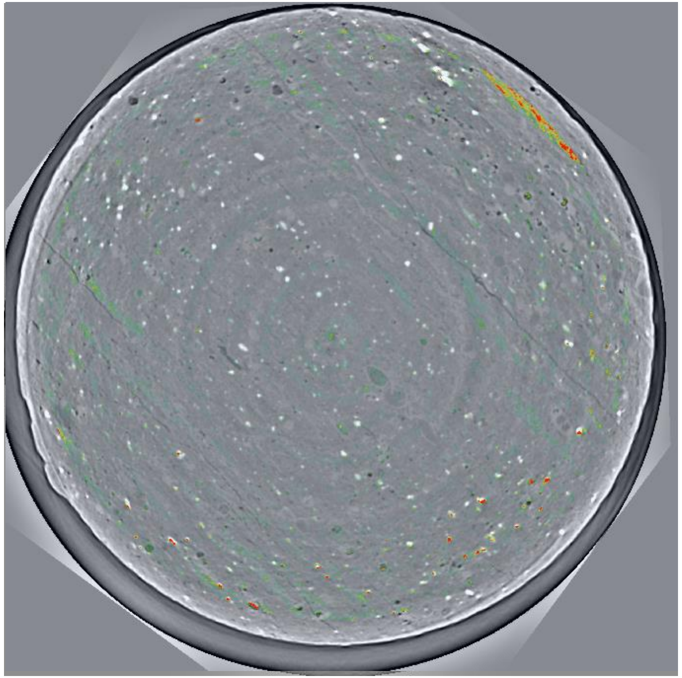
- Lighter color: after water imbibition
- No water imbibition in the matrix

Residual oil in a fracture

- Water imbibition in the oil-imbibed sample
- Displacement of oil by water in fracture
  - Non-uniform
- Residual oil saturation
  - 15-60%
- Influencing factors
  - Fracture configuration
  - Wettability



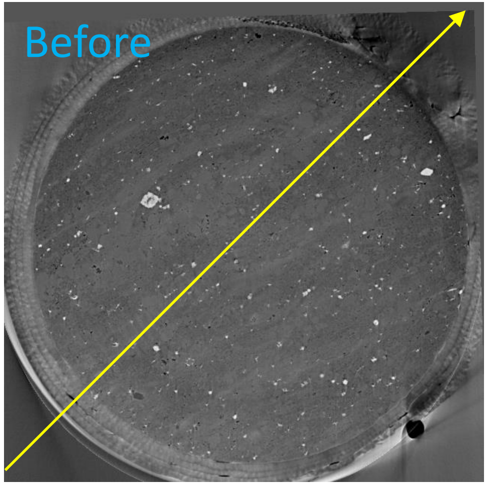
Example of no imbibition in fractures

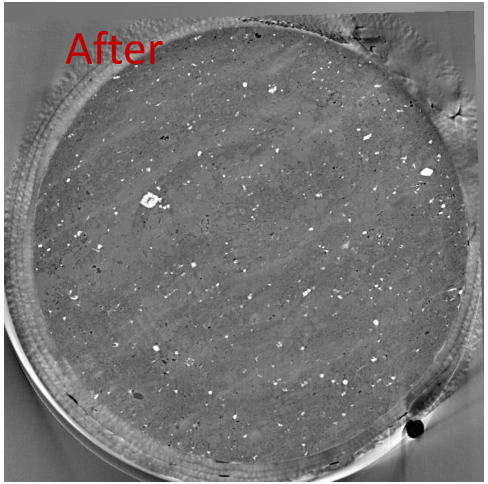


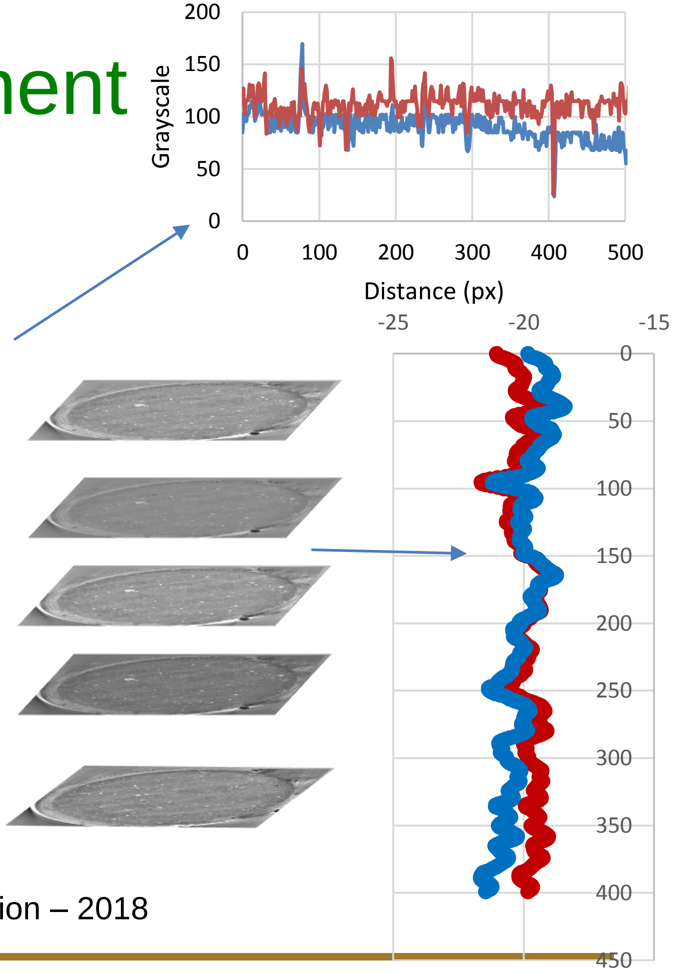
- Fractures are not always the preferential flow path
  - Wettability
- Still many unknown
  - Local mineralogy?
  - Sample condition?
  - Absorbed water or oil film?

Importance of image pre-treatment

- Precise alignment (registration)
- Background grayscale correction







Immiscible two-phase flow related parameters

	CH_2I_2	decane	dodecane
Viscosity 20 °C (mPa.S)	2.76	0.86	1.36
Interfacial surface tension at 20 °C (oil-water, mN/m)	35.8†	52.3*	52.8*
Density (g/mL)	3.32	0.73	0.75
M (relative to water)	3.1	0.97	1.53
Ca normalized by Ca_CH_2I_2	1.0	0.21	0.33
Re normalized by Re_CH_2I_2	1.0	0.71	0.46

- M: mobile ratio
- Ca: capillary number
- Re: Reynolds number

† from Dataphysics (1998)
* from Zeppieri et al. (2001)

- M, Ca, Re: Same order of magnitude
- Two-phase fluid flow behavior of CH_2I_2: comparable to decane or dodecane

Key points

- Complexity and heterogeneity of multi-phase fluid flow in micro-fracture and matrix in shale are documented/visualized for the first time
- Influencing factors, including wettability and connectivity, are discussed, but still many unknowns exist
- Nevertheless, the technique of tracer plus micro-CT provides an avenue for further exploration of multiphase flow and related applications, such as flow under pressure, water-oil distribution, EOR, etc.

Acknowledgement

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