Multiphase flow of CO_2 and water in reservoir rocks at reservoir conditions

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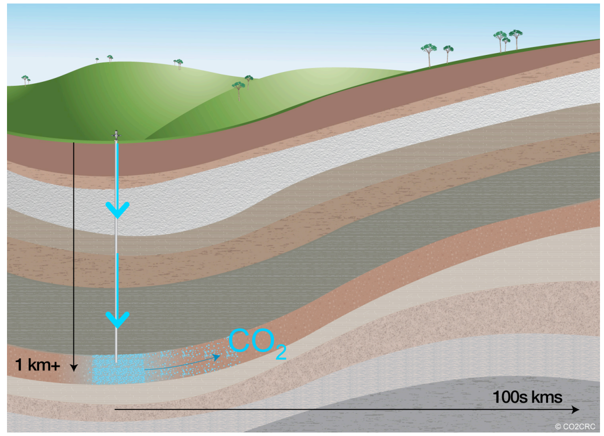
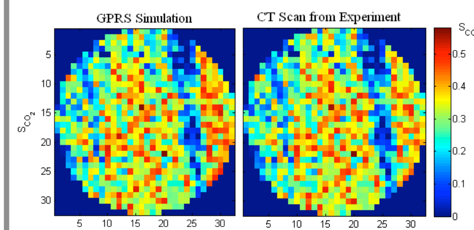
Multiphase flow properties

sample collection

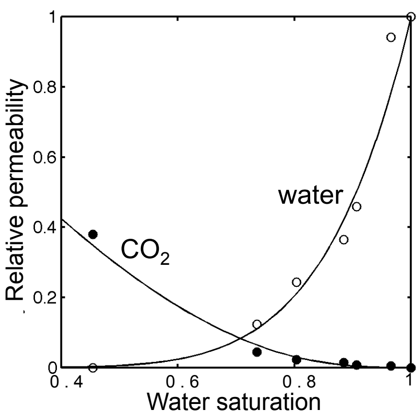


simulations

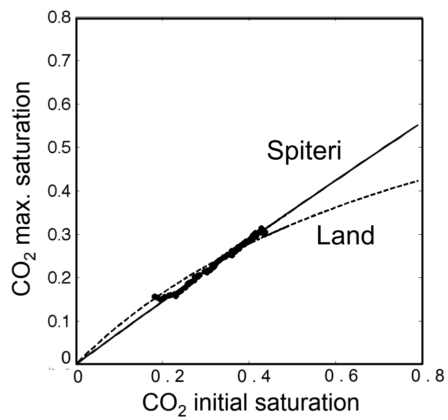


Core flooding experiments

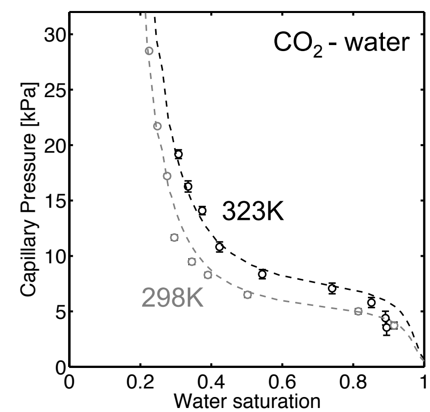
relative permeability



residual trapping



capillary pressure

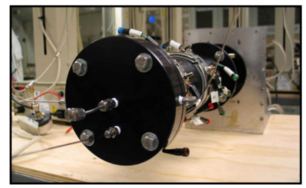


Core-flooding experiments

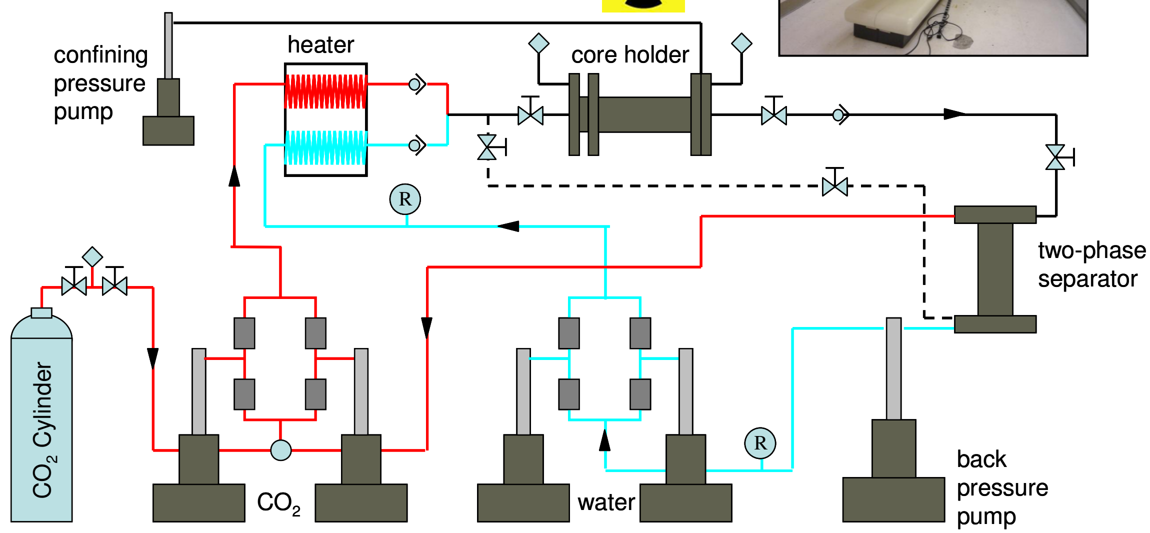
- Replicate reservoir conditions
  - P_{pore} : 9 MPa
  - P_{conf}: 11.8 MPa
  - T: 50C
- Continuous circulation
- Immiscible displacement
- Experimental variables:
  - Flow rates
  - Pressure drop
  - Saturation (CT scanner)

Perrin J-C. and Benson S., *Trans Porous Media.* **2010,** *82*, 93-109

Core-holder



X-ray CT scanner



CO_2/Water ISCO pumps

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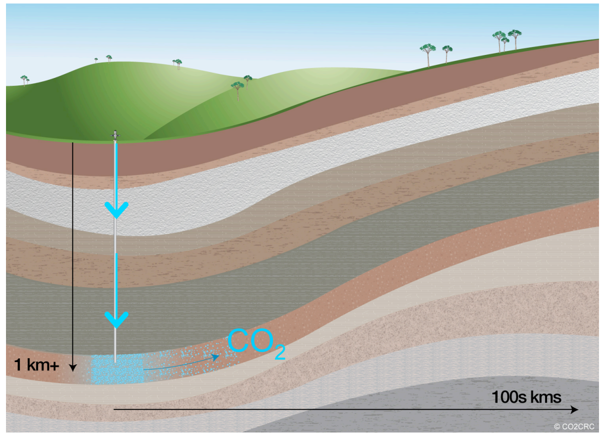
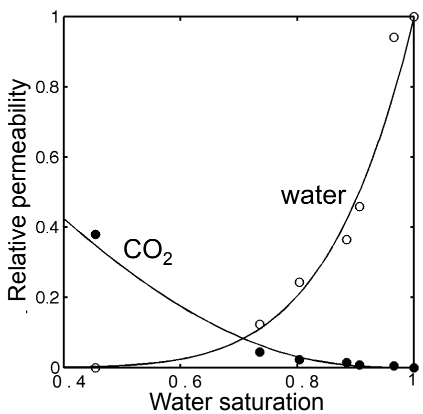
GCEP

Multiphase flow properties

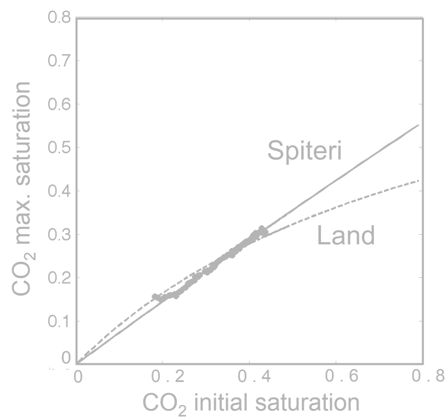


Core flooding experiments

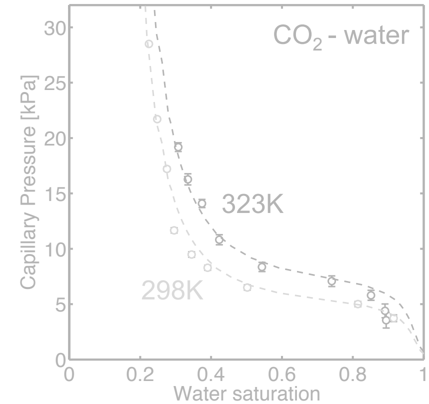
relative permeability



residual trapping

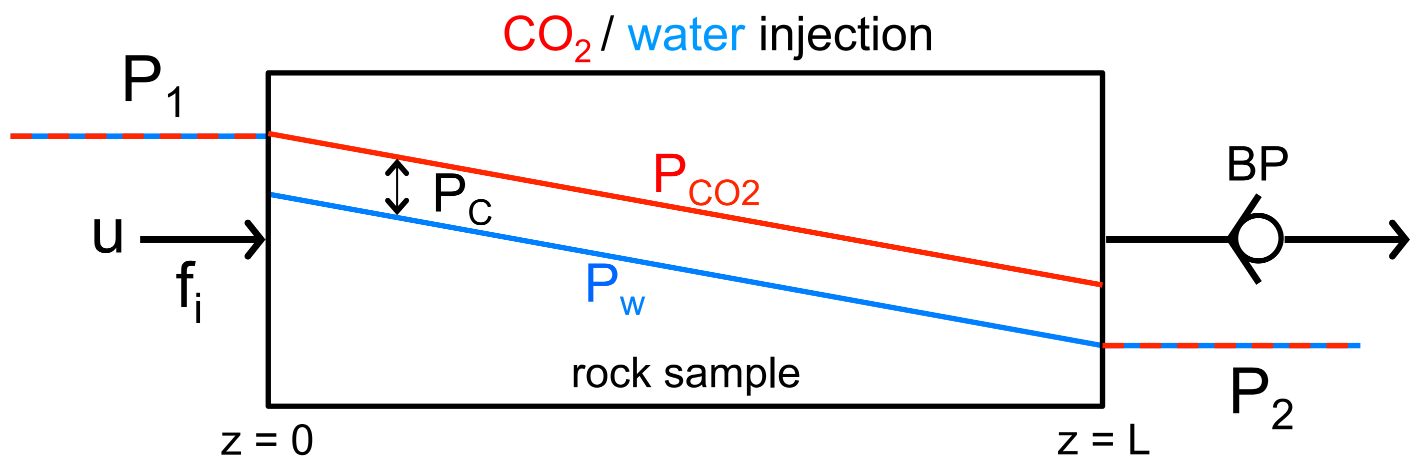


capillary pressure



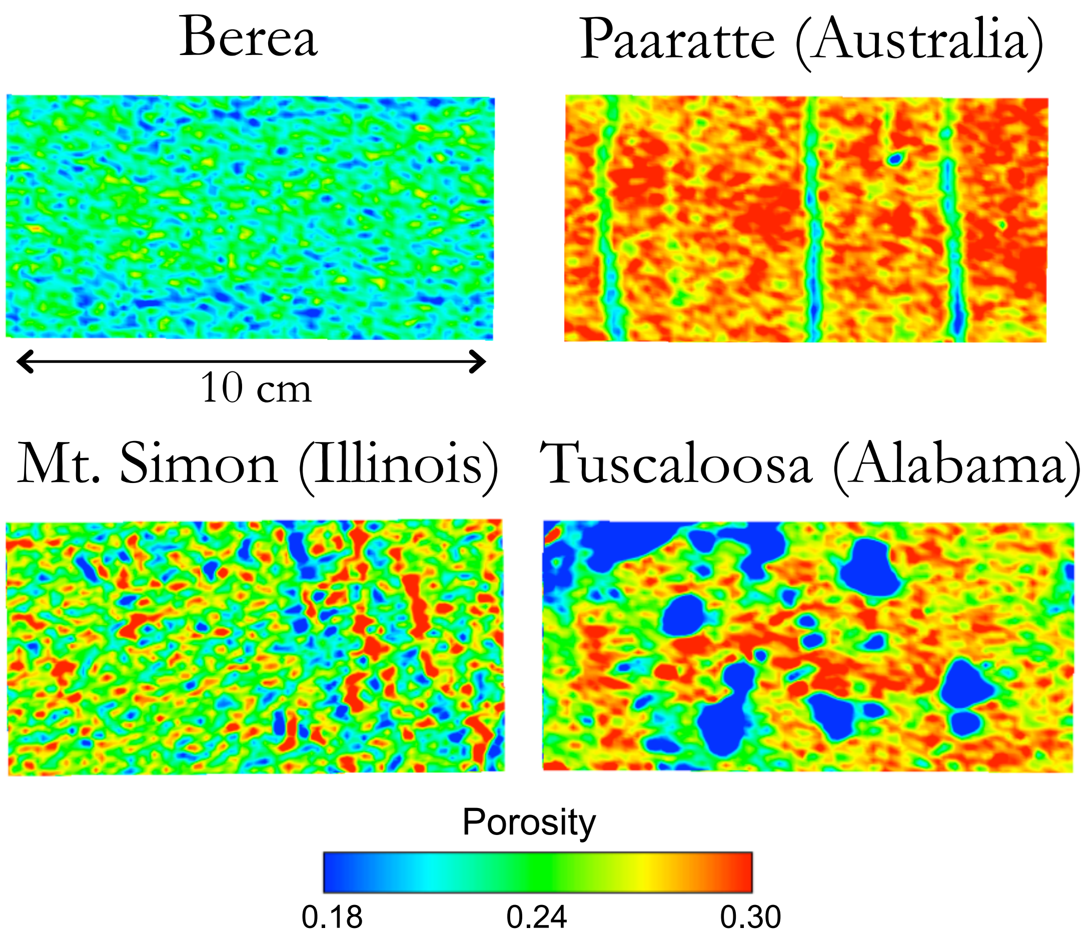
Relative permeability

Steady state method



$$u_i = -\frac{k k_{ri}(S_i)}{\mu_i}\frac{dP_i}{dz} \xrightarrow[\text{steady state}]{S_i = \text{constant} \;\rightarrow\; \frac{dP_c}{dz} = 0} u_i = -\frac{k k_{ri}(S_i)}{\mu_i}\frac{\Delta P}{L}$$

Rock samples



- Sandstones
- Berea: "model" rock
- Others: target CO_2 storage reservoirs

Name	Porosity [-]	Absolute Permeability [mD]
Berea	22.1	914
Paaratte	28.3	1156
Mt. Simon	24.4	7.5
Tuscaloosa	23.6	220

Relative permeability - Results

- Flow rate:

$$q_t = 10 - 15 \text{ml/min}$$

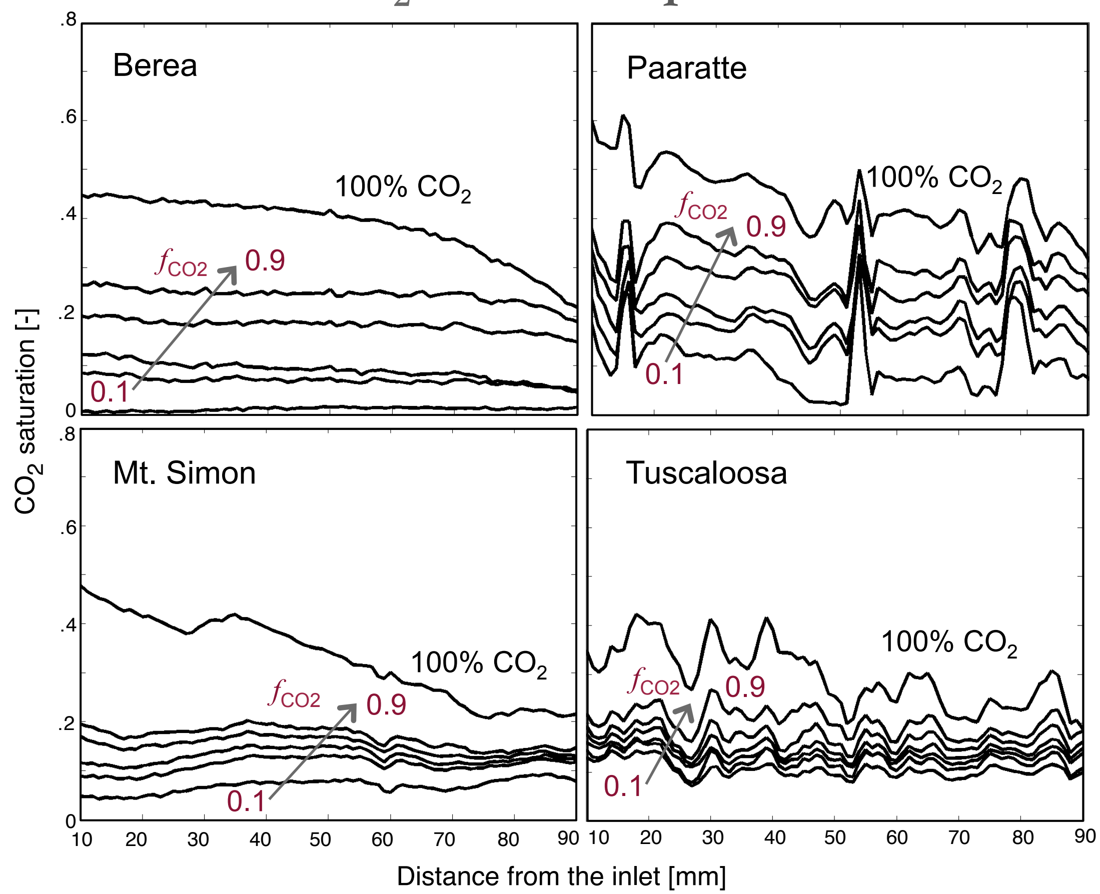
$$f_{CO2} = \frac{q_{CO2}}{q_t} = 0.1 - 1$$

- Steady-state: 5 PVI
- 100% CO_2 injection alternative technique*

→ Flat saturation profiles

→ Core heterogeneity

CO_2 saturation profiles



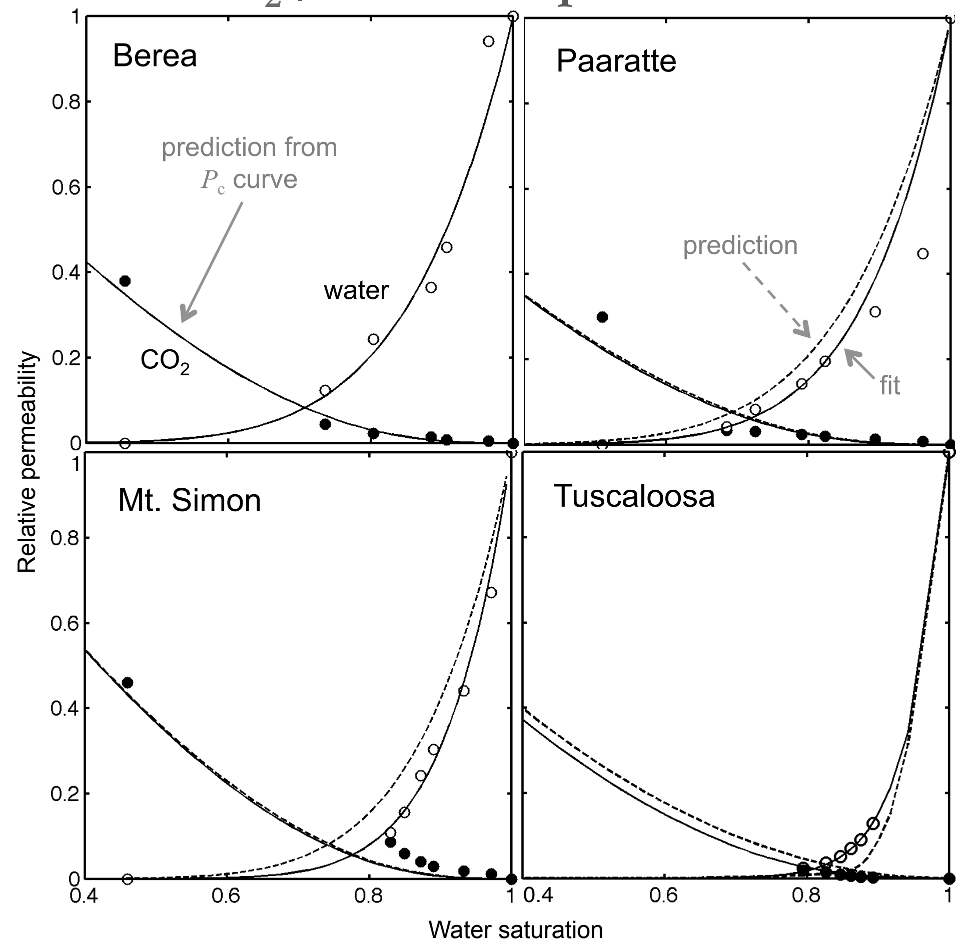
*Ramakrishnan T.S. and A. Cappiello, *Chem. Eng. Sci.* **1991**, 46(4), 1157-1163

Relative permeability curves

$$k_{ri}(S_i) = -\frac{L\mu_i u_i}{\Delta P k}$$

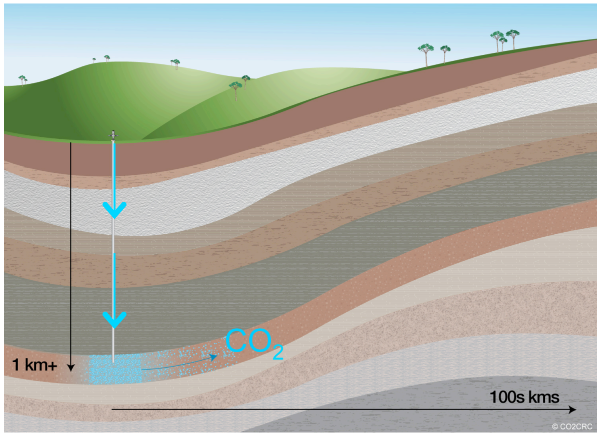
- Features are qualitatively predicted from MICP measurements
- Typical behavior of a strongly water-wet gas/water system
- Viscosity ratio controls end-point saturation (f_{CO2}=1)

CO_2 / water rel. perm. curves



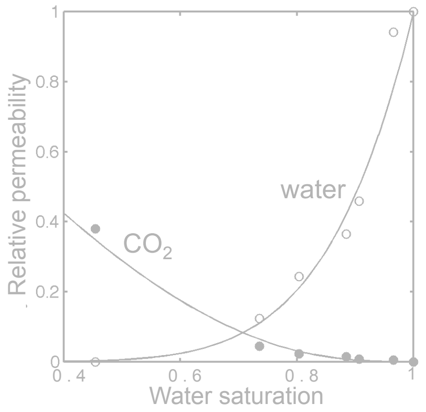
Krevor S. et al., *Water Resources Research* **2011,** submitted

Multiphase flow properties

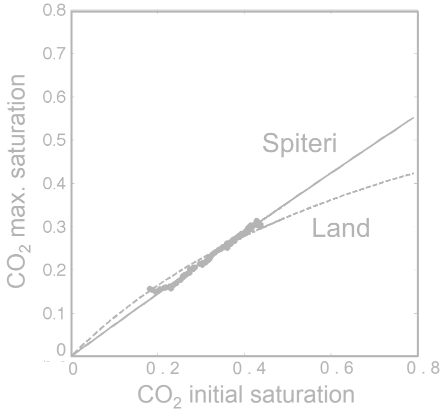


Core flooding experiments

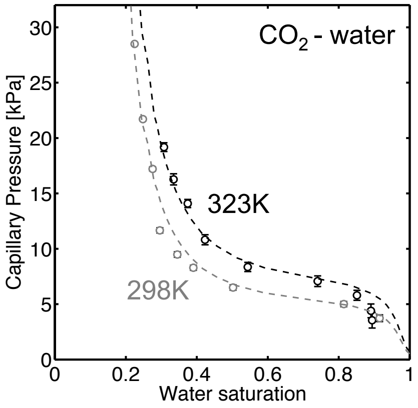
relative permeability



residual trapping

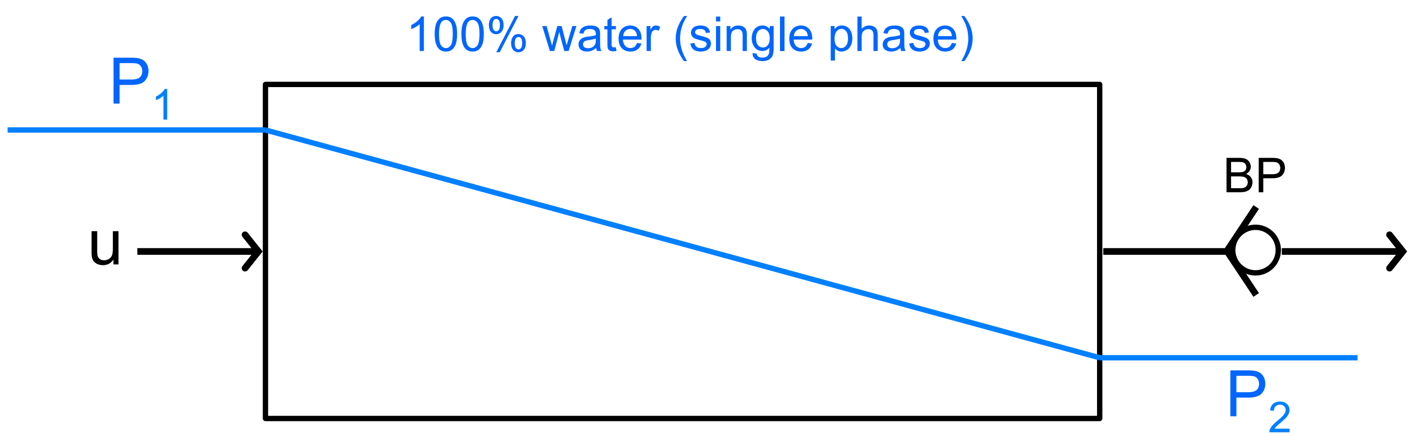


capillary pressure



The method

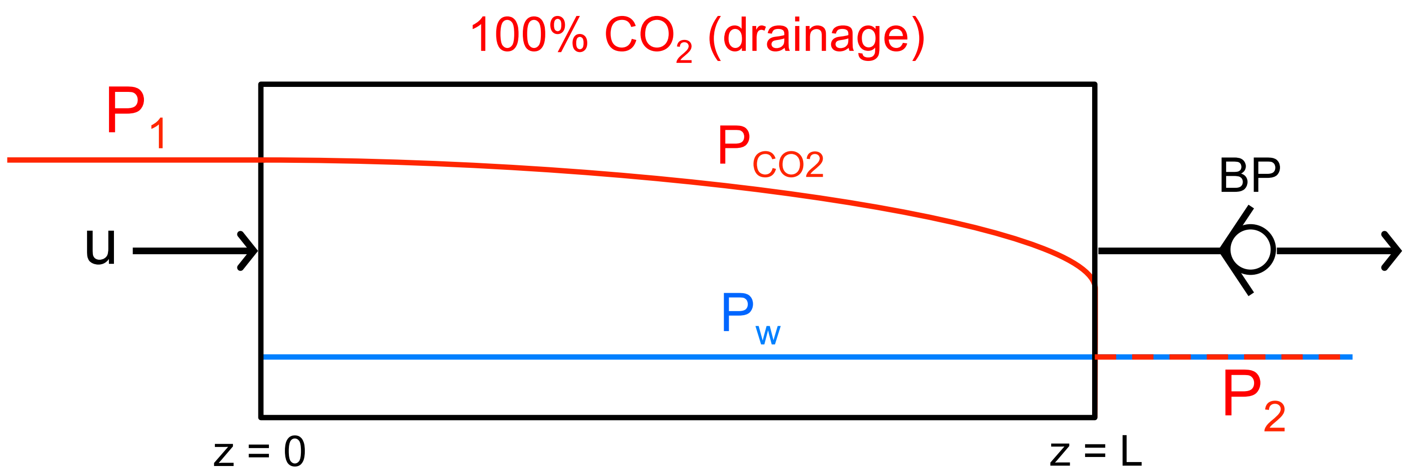
Capillary pressure measurement during a core-flooding experiment



Darcy's law: $$u = -\frac{k}{\mu}\frac{\Delta P}{L}$$

The method

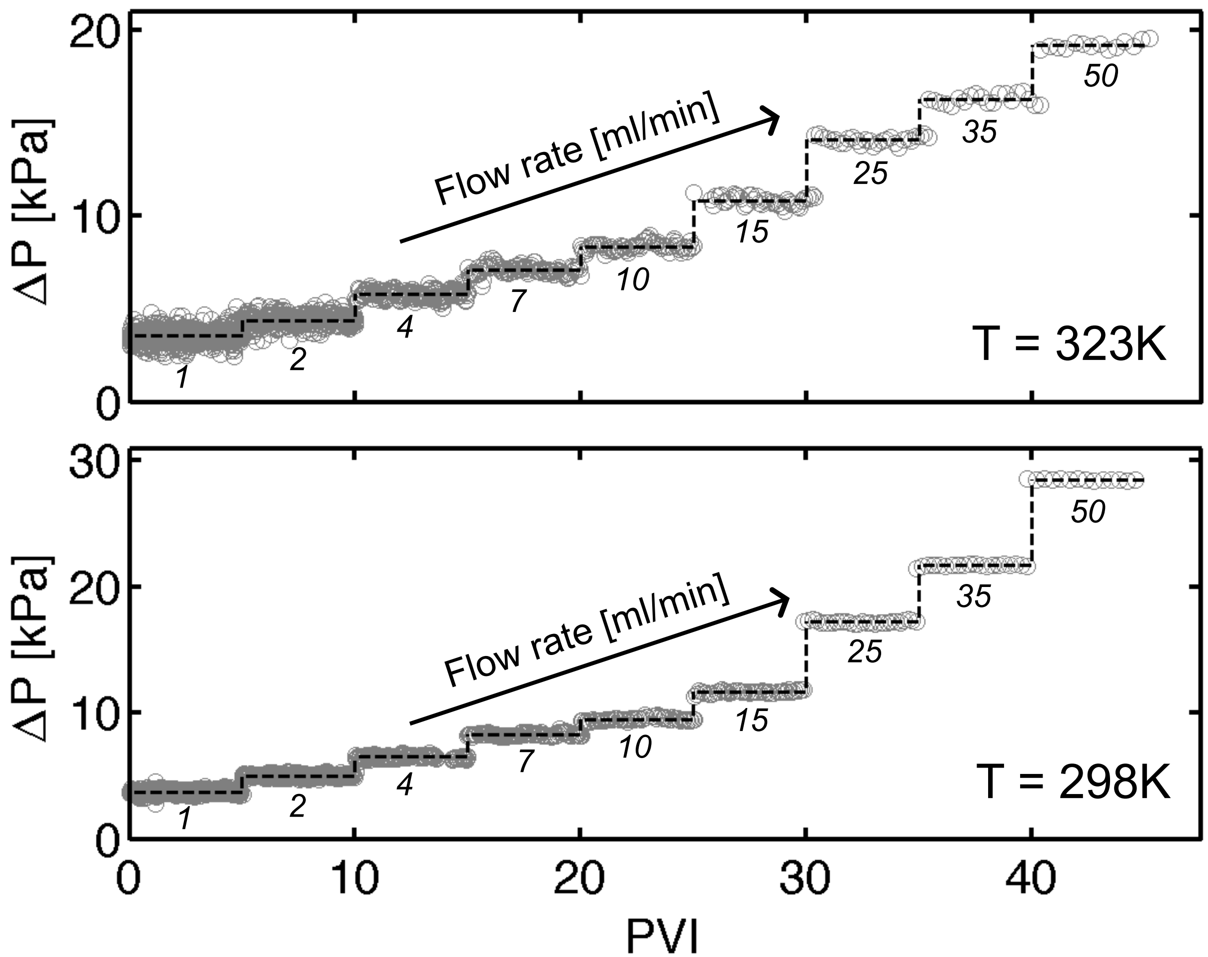
Capillary pressure measurement during a core-flooding experiment



Steady state: $u_w = 0 \rightarrow \frac{dP}{dz} = \frac{dP_c}{dz} \rightarrow \Delta P = P_c\big|_{z=0}$

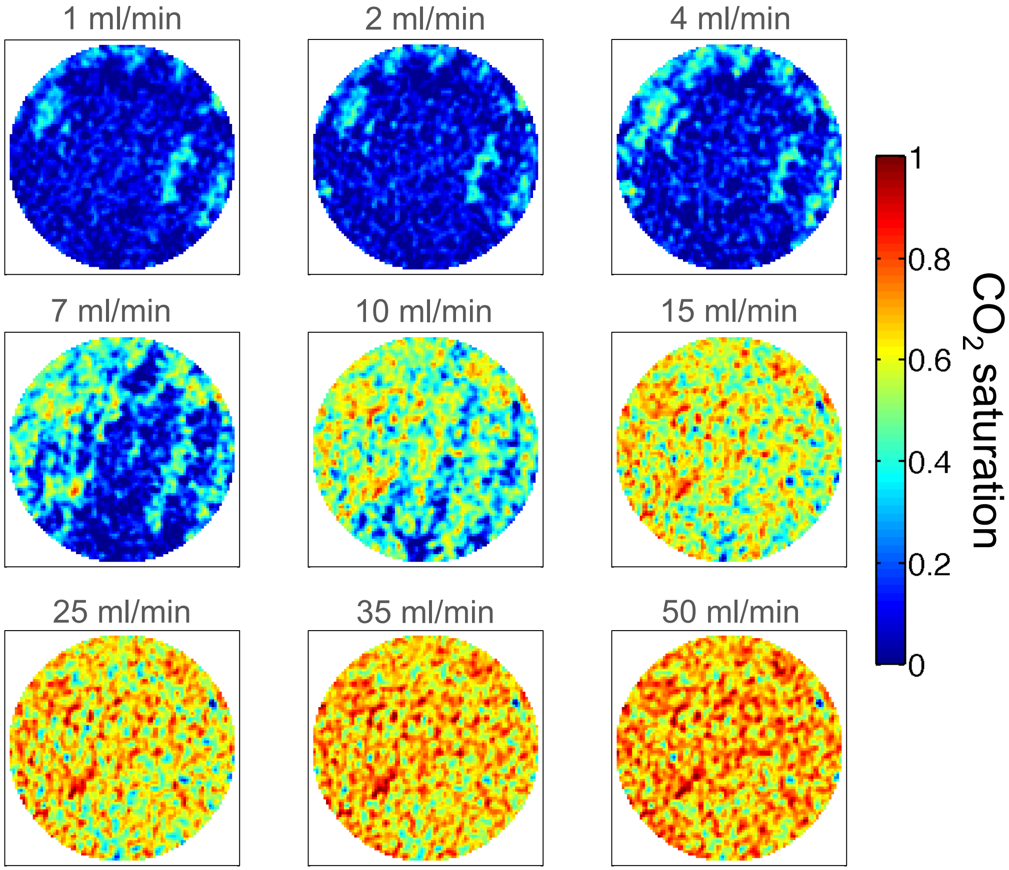
Experiment - Pressure drop

- Berea (280 mD)
- Flow rates:
  - 1 – 50 ml/min
- Injection of 5 PVI for each step
- Average over the last 1 PVI
- Viscosity
  - 298 K: 7.1 10^{-5} Pa s
  - 323 K: 2.3 10^{-5} Pa s

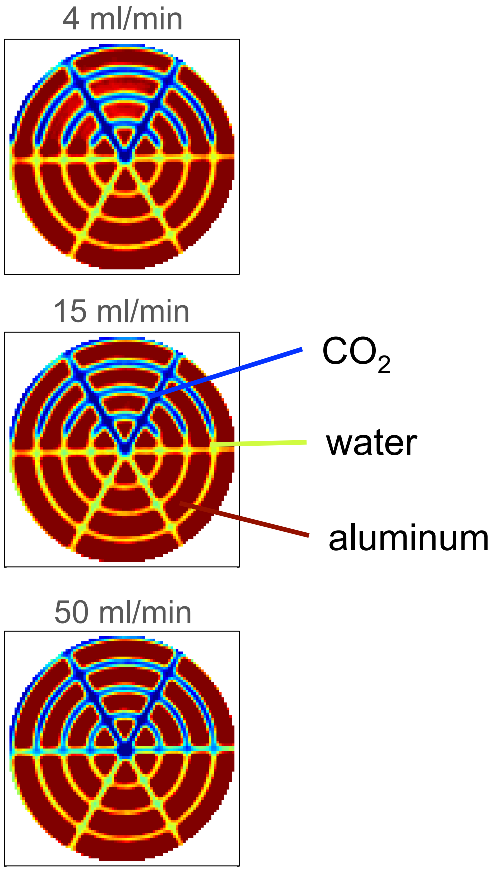


Experiment – CT scan (323 K)

Inlet slice (20x)

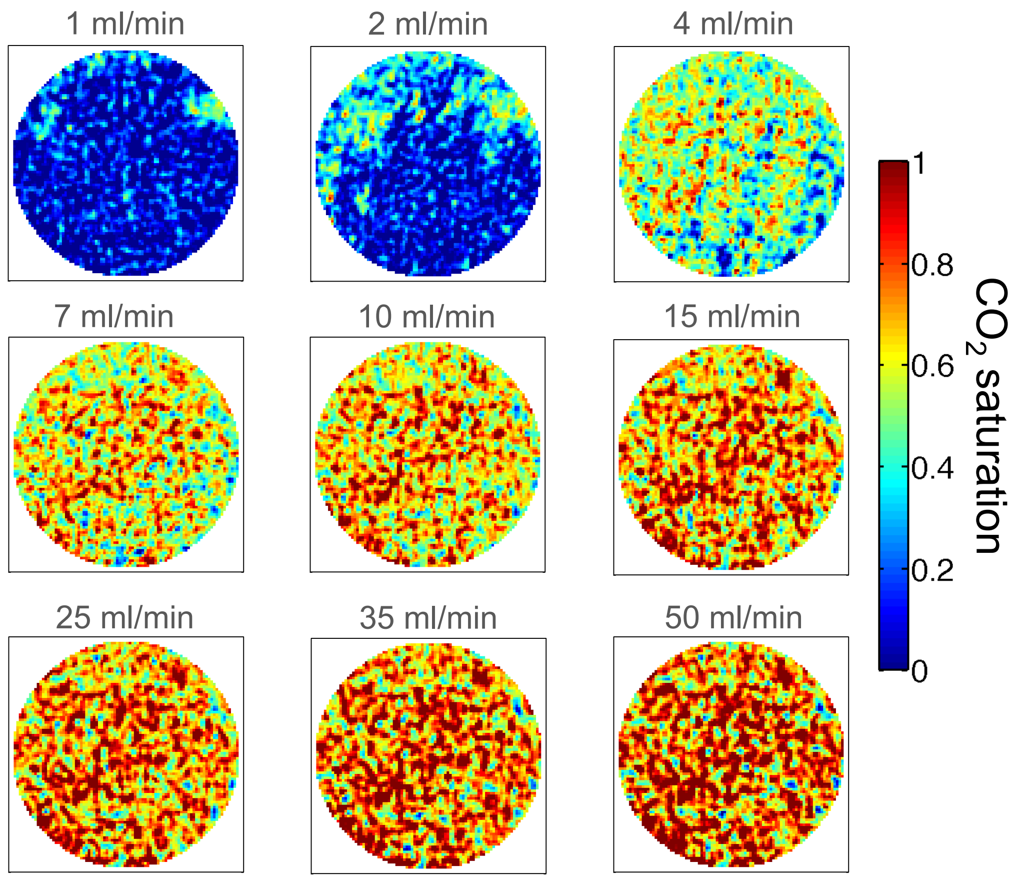


Outlet slice

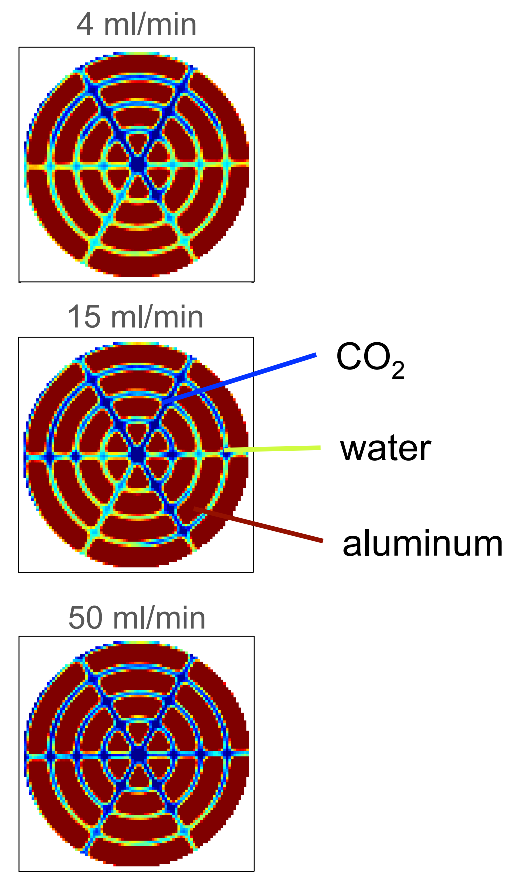


Experiment – CT scan (298 K)

Inlet slice (20x)



Outlet slice



Capillary pressure curve

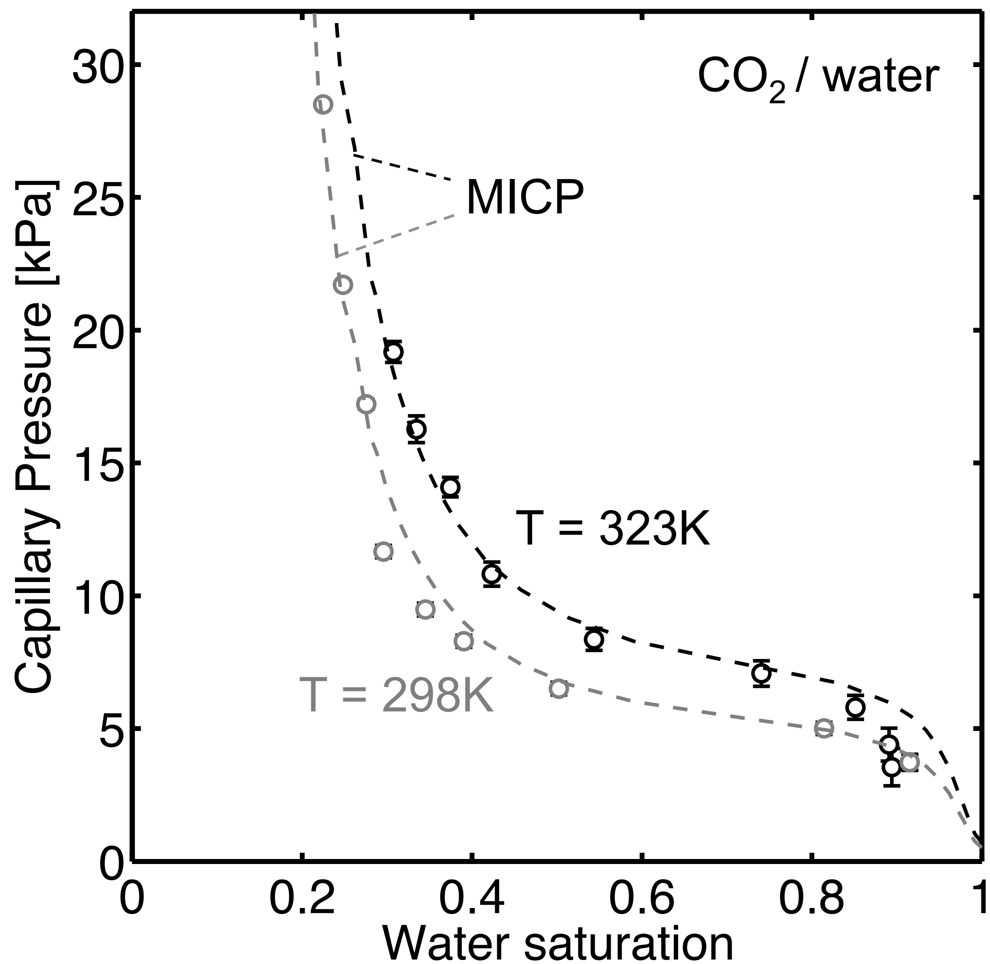
$$P_{c,CO2/w} = P_{c,m/a} \frac{\sigma_{CO2/w} \cos\theta_{CO2/w}}{\sigma_{m/a} \cos\theta_{m/a}}$$

CA: $\theta_{CO2/w} = 180^{o}$ $\theta_{m/a} = 140^{o}$

IFT: $\sigma_{m/a} = 485$ mN/m

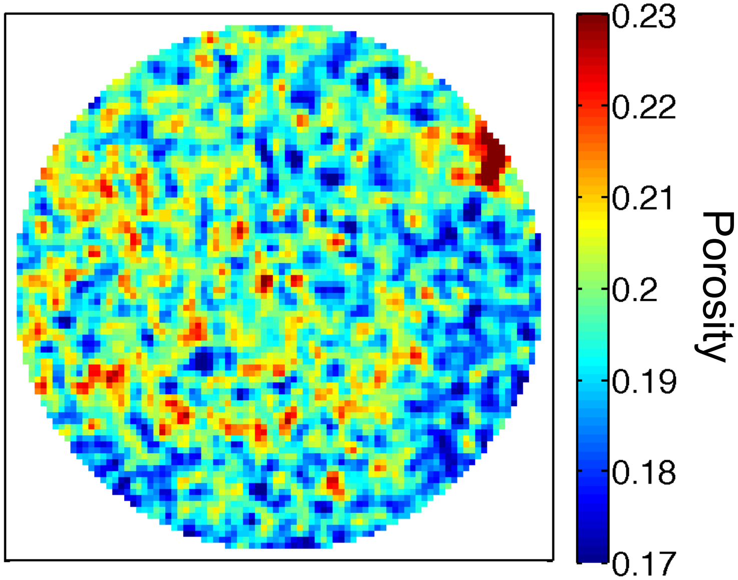
$\sigma_{CO2/w}$[mN/m]	**298 K**	**323 K**
Fit (exps.)	28.1	38.7
Literature*	29.5	35.5

* Georgiadis A. et al, *J. Chem. Eng. Data* **2010,** *55,* 4168–4175
Chiquet P. et al., *Energy Convers. Manage.* **2007,** *48*, 736–744

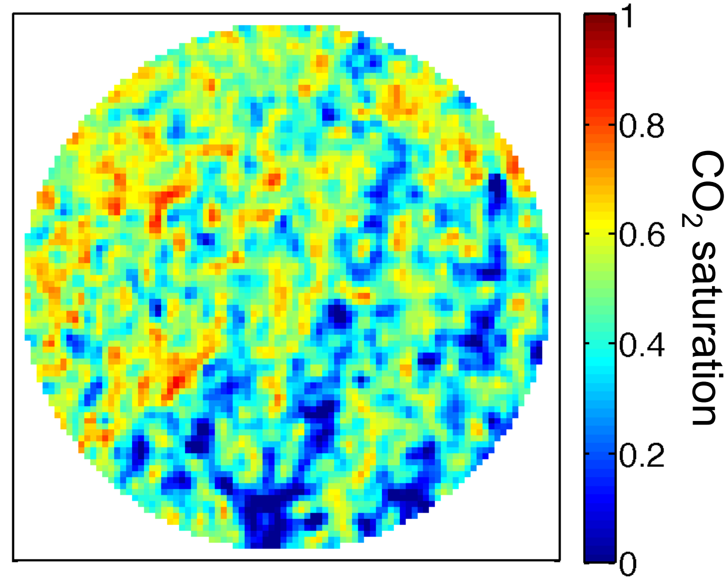


Capillary pressure - heterogeneity

Porosity



Saturation*

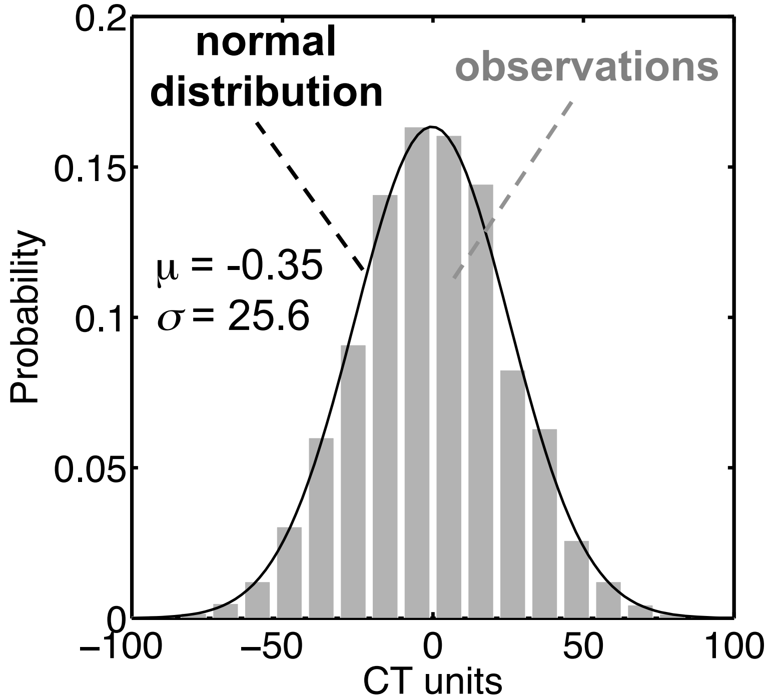


* 323 K, 10 ml/min

At the sub-core scale, a saturation distribution can be associated to a given capillary pressure

CT scan precision - assessment

Subtracting two scans



*120 kV, 200 mA, 25 DFOV

- Normal distribution

  $$N\left(\mu,\sigma^2\right)$$

- Random error

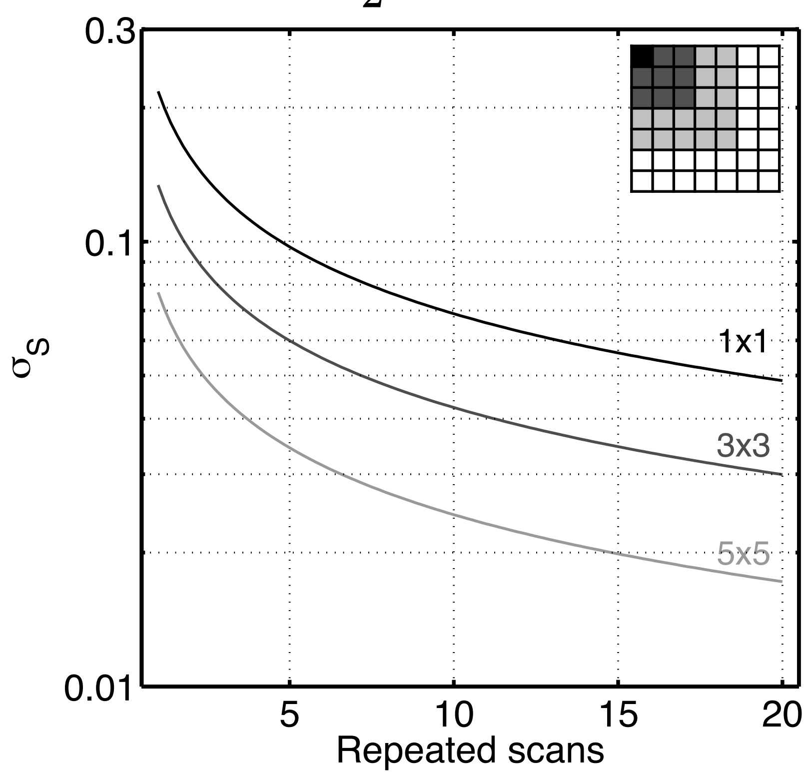
  ⟶ averaging helps!

- Error propagation

$$c = f(a,b) \;\rightarrow\; \sigma_c^2 = \sigma_a^2\left(\frac{\partial c}{\partial a}\right)^2 + \sigma_b^2\left(\frac{\partial c}{\partial b}\right)^2$$

CT scan precision - assessment

CO_2 saturation



*120 kV, 200 mA, 25 DFOV

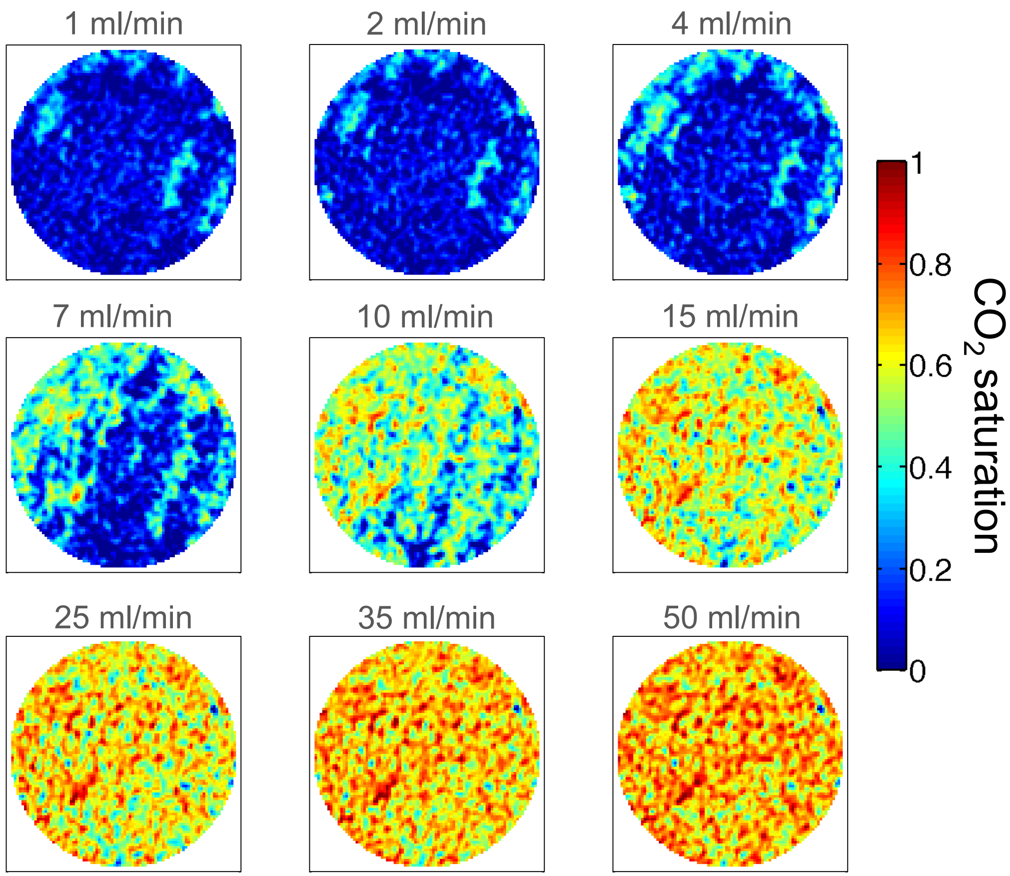
$$S = \frac{CT_{\text{ws/r}} - CT_{\text{wsg/r}}}{CT_{\text{ws/r}} - CT_{\text{g/r}}}$$ with $CT_{i/\text{r}}$ affected by σ_{pix}

$$\sigma_S = \frac{\sqrt{2}\sigma_{\text{pix}}}{CT_{\text{ws/r}} - CT_{\text{g/r}}} \underbrace{\sqrt{1 + \left(\frac{CT_{\text{ws/r}} - CT_{\text{wsg/r}}}{CT_{\text{ws/r}} - CT_{\text{g/r}}}\right)^2}}_{\approx 1}$$

Uncertainty	$\sigma_{S,1}$	$\sigma_{S,20}$
1×1	0.22	0.049
3×3	0.13	0.03
5×5	0.077	0.017

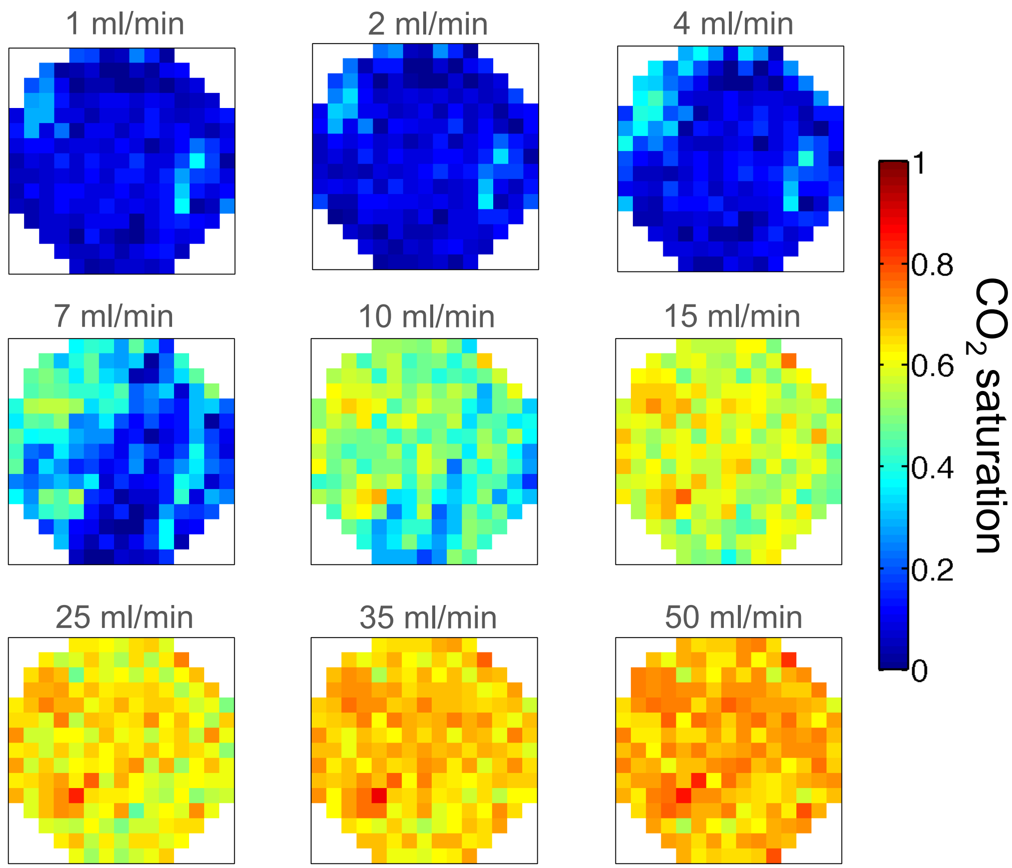
Experiment – CT scan (323 K)

Inlet slice (20x) – CO_2 saturation

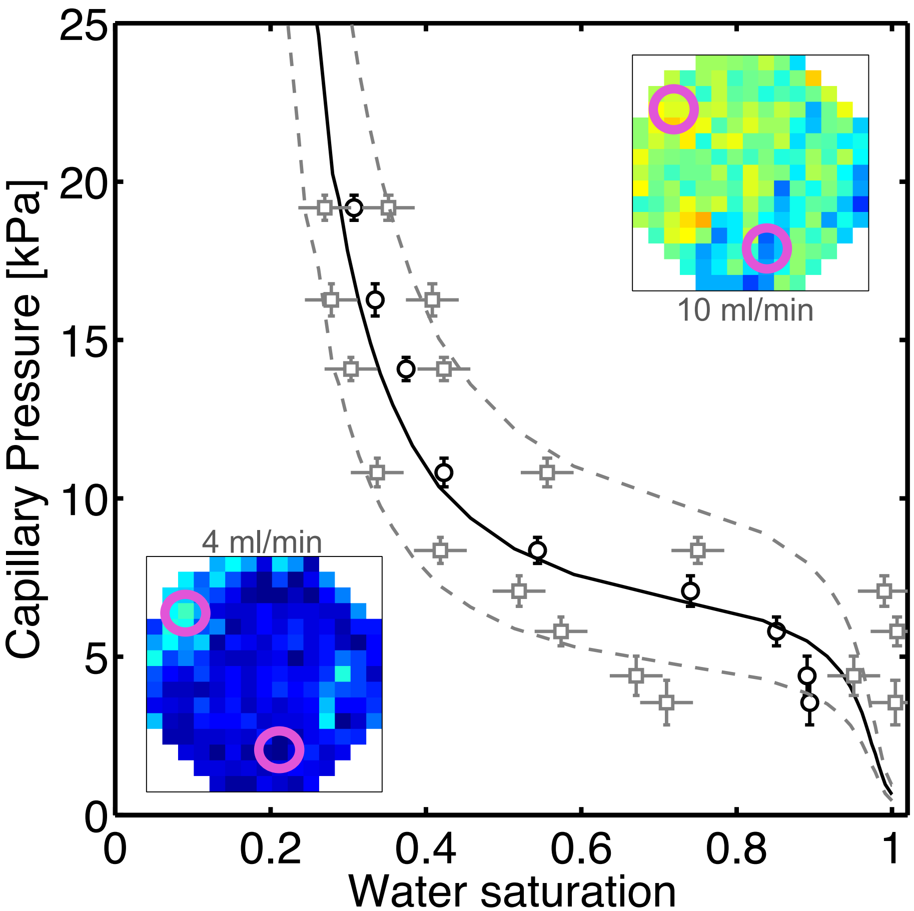


Experiment – CT scan (323 K)

Inlet slice (20x + 5x5) – CO_2 saturation



Capillary pressure - heterogeneity



- Coarsening
  - 5 x 5
- Pixel size:
  - 2.5 x 2.5 mm
- Uncertainty *S*
  - σ_S = 1.7% (abs.)

Each pixel possesses a unique capillary pressure curve!

Concluding remarks

- CO_2/water relative permeability and capillary pressure curves have been measured on reservoir rocks at reservoir conditions
- Generally, results are typical for a strongly water-wet system
- Relative permeability:
  - Low CO_2:water viscosity ratio results in low CO_2 saturations and accordingly low relative permeability
- Capillary pressure:
  - Results are consistent with MICP and expectations from changes in temperature
  - The technique allows to assess and quantify the heterogeneity of the capillary pressure at the sub-core scale