Characterizing multiphase flow in heterogeneous carbonates

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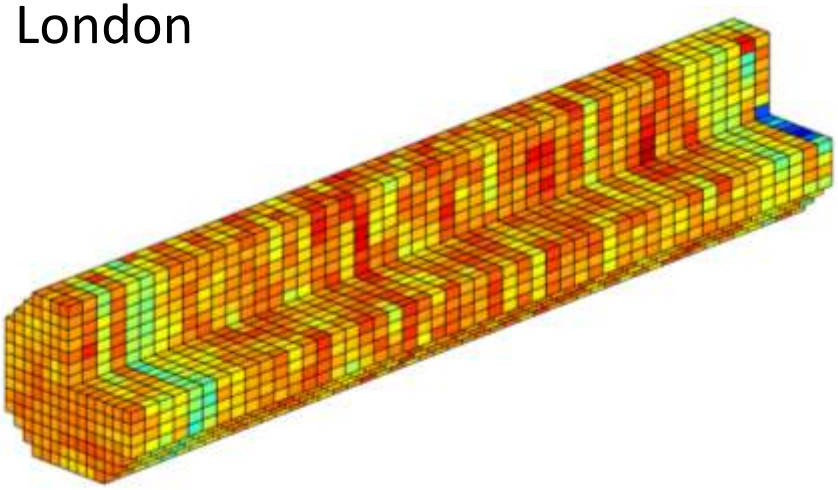
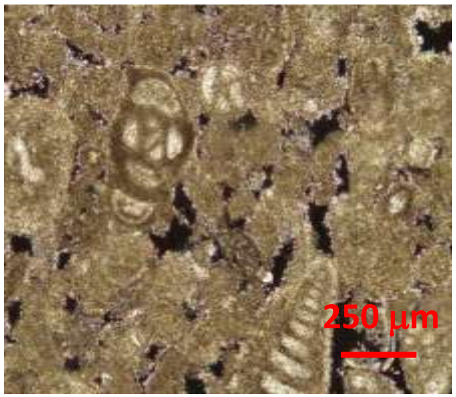
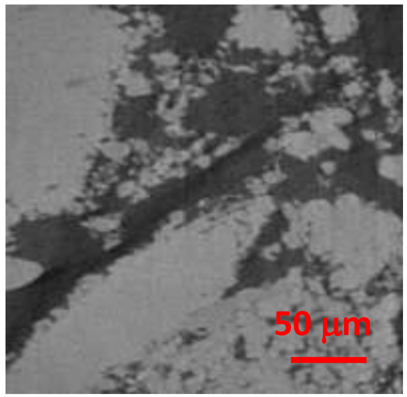
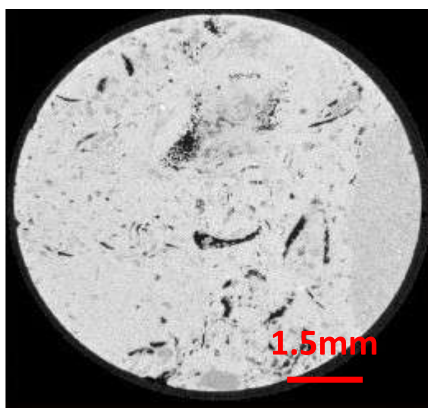


Petrophysics in support of potential storage sites in Switzerland: heterogeneous carbonates



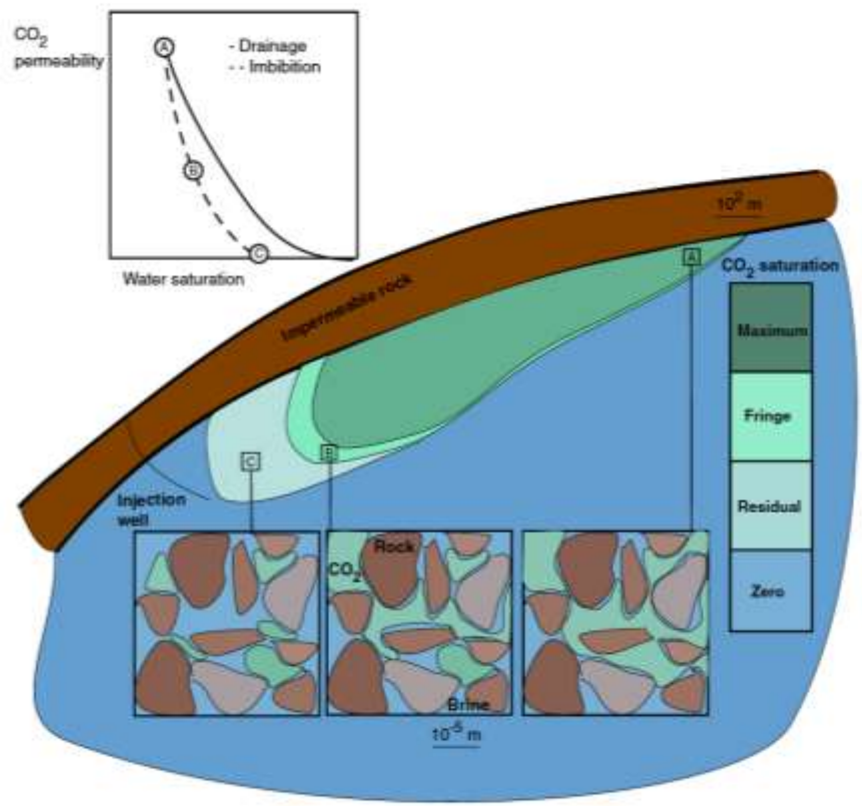




Sun, H., Belhaj, H., Tao, G., Vega S., & Liu, L. (2019). Rock properties evaluation for carbonate reservoir characterization with multi-scale digital rock images. Journal of Petroleum Science & Engineering, **175,** 654-664.

- Analogue samples for the ELEGANCY Swiss case study
- Need to understand how to characterise the impact of heterogeneity on flow and trapping in the laboratory
- Workflows for homogeneous samples are mature
- Characterising heterogeneous rocks is complicated by the lack of Representative Elementary Volume

Objective : Characterise the impact of multi-scale rock heterogeneity on flow and trapping in carbonate reservoirs

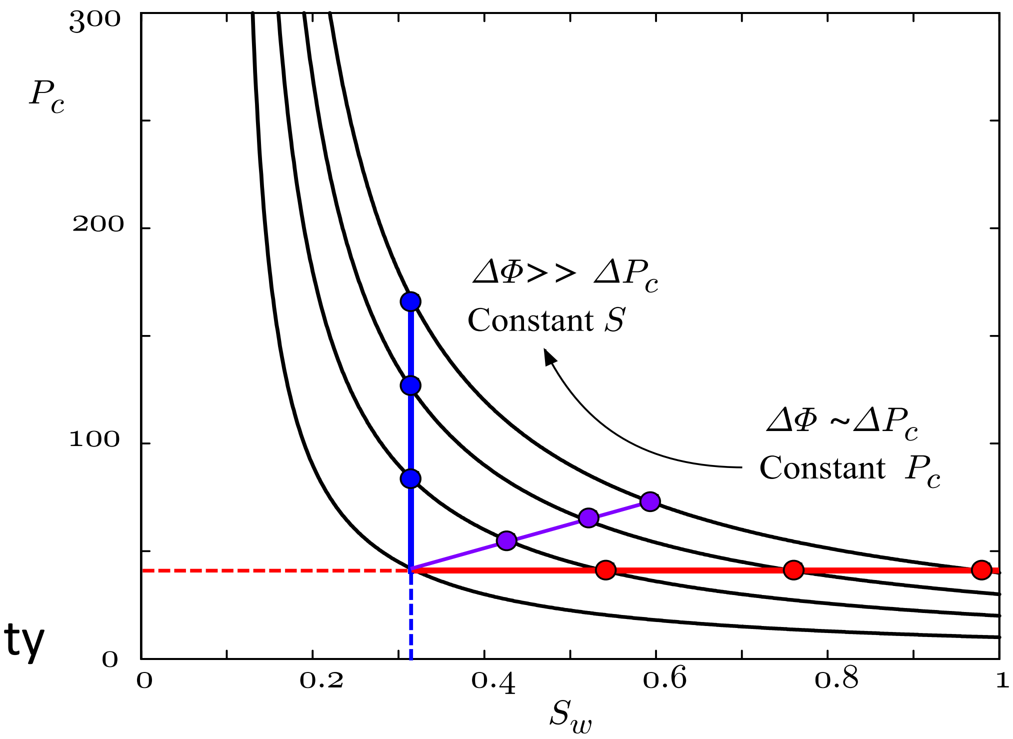


- Modeling is required for prediction of flow behavior and trapping of CO_2 in reservoirs
- Models are informed by multiphase flow properties which depend on the fluid saturation
  - ✓ Capillary Pressure
  - ✓ Relative Permeability
  - ✓ Residual Trapping

Krevor, S., Blunt, M. J., Benson, S. M., Pentland, C. H., Reynolds, C., Al-Menhali, A., & Niu, B. (2015). Capillary trapping for geologic carbon dioxide storage–From pore scale physics to field scale implications. International Journal of Greenhouse Gas Control, **40,** 221-237.

Why does heterogeneity impact flow?

- Heterogeneity in capillary pressure function controls the saturation distribution
- Low flow potential: Small heterogeneities can lead to large variations in saturation
- Larger flow potential leads to homogenous saturations
- Heterogeneous saturation leads to heterogeneity in relative permeability and flow rate dependent transport



$$N_c = \frac{H}{|\Delta P_c(f_w)|} \frac{\Delta P}{L}$$

Virnovsky, G. A., Friis, H.A., Lohne, A. (2004). A Steady-State Upscaling Approach for Immiscible Two-Phase Flow. Transport in Porous Media **54,** 167-192.

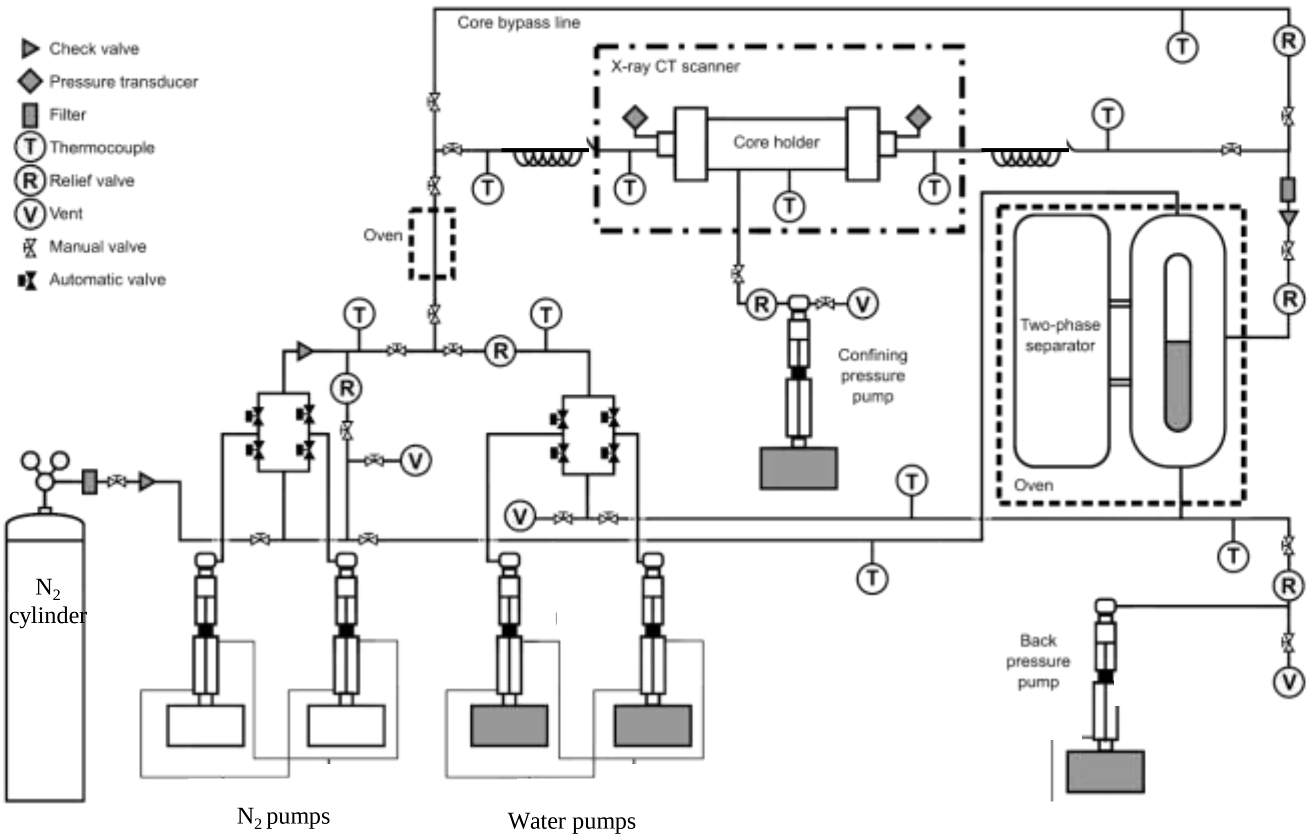
Rock samples are heterogeneous carbonates, analogues for potential storage sites in Switzerland

- Estaillades
  - ✓ Cretaceous biclastic limestone found in Oppède quarry, France
  - ✓ Calcite cemented grainstone made up of fossil fragments & oolites
  - ✓ 99% calcite, 1% dolomite and silica

- Indiana
  - ✓ Quarried from Salem formation located in Indiana
  - ✓ 97.07% calcite, 1.2 % dolomite, 0.8 silica and iron oxide

- Edward Brown
  - ✓ From Texas, USA
  - ✓ Dominated by dolomite and calcite and small amount of quartz usually less than 10%

A steady state elevated pressure core flood rig was used with N_2 as an analogue to CO_2



P = 100 bar
T = 20^0 C

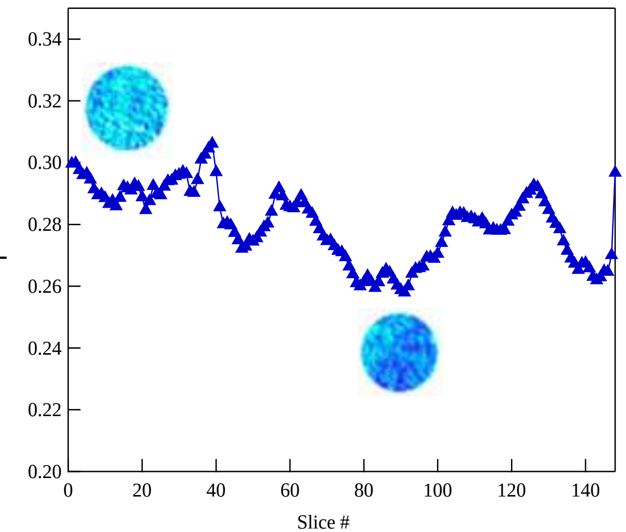
$$K = \frac{q\ \mu\ L}{A\ \Delta\ P}$$

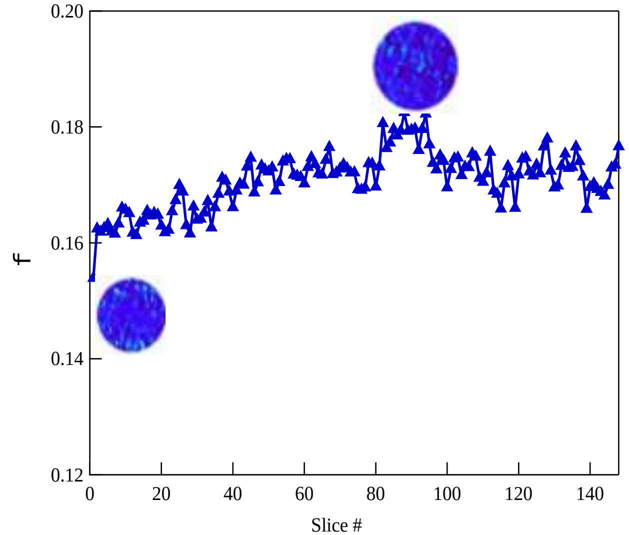
$$k_{r,i}(S_i) = \frac{q\ \mu_{\ i}\ L}{A\ K\ \Delta\ P}$$

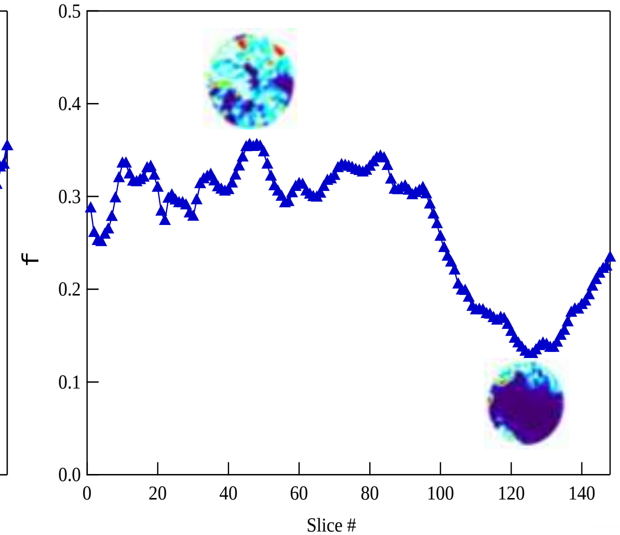
$$S_w = 1 - S_{N2}$$

$$S_{N2} = \frac{CT_{exp}\ -\ CT_{water}}{CT_{N2}\ -\ CT_{water}}$$

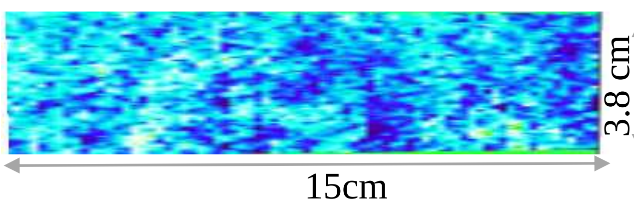
Porosity heterogeneity in the samples

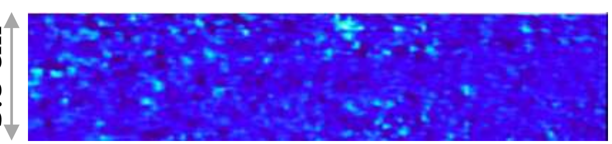


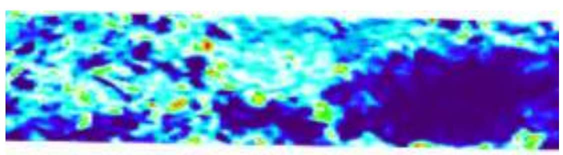


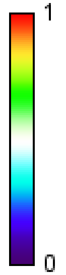


Center slice along the length





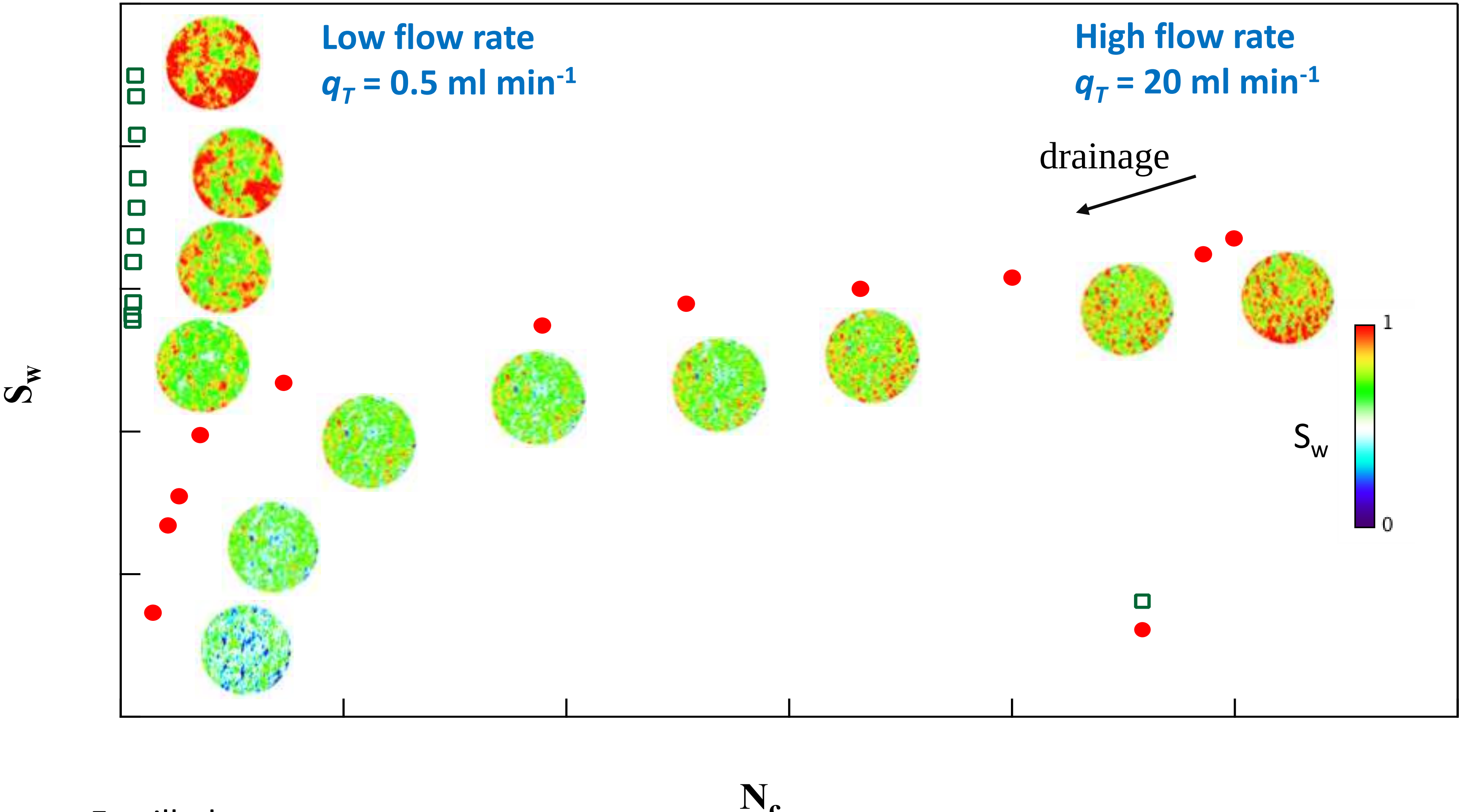




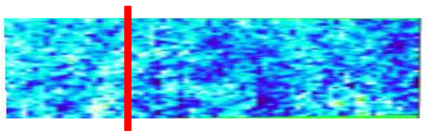
Estaillades Indiana Edward Brown

	Estaillades	Indiana	Edward Brown
Average Porosity	0.28	0.17	0.26
Average Permeability (mD)	140	24	46

Heterogeneity impacts 3D saturations



Estaillades

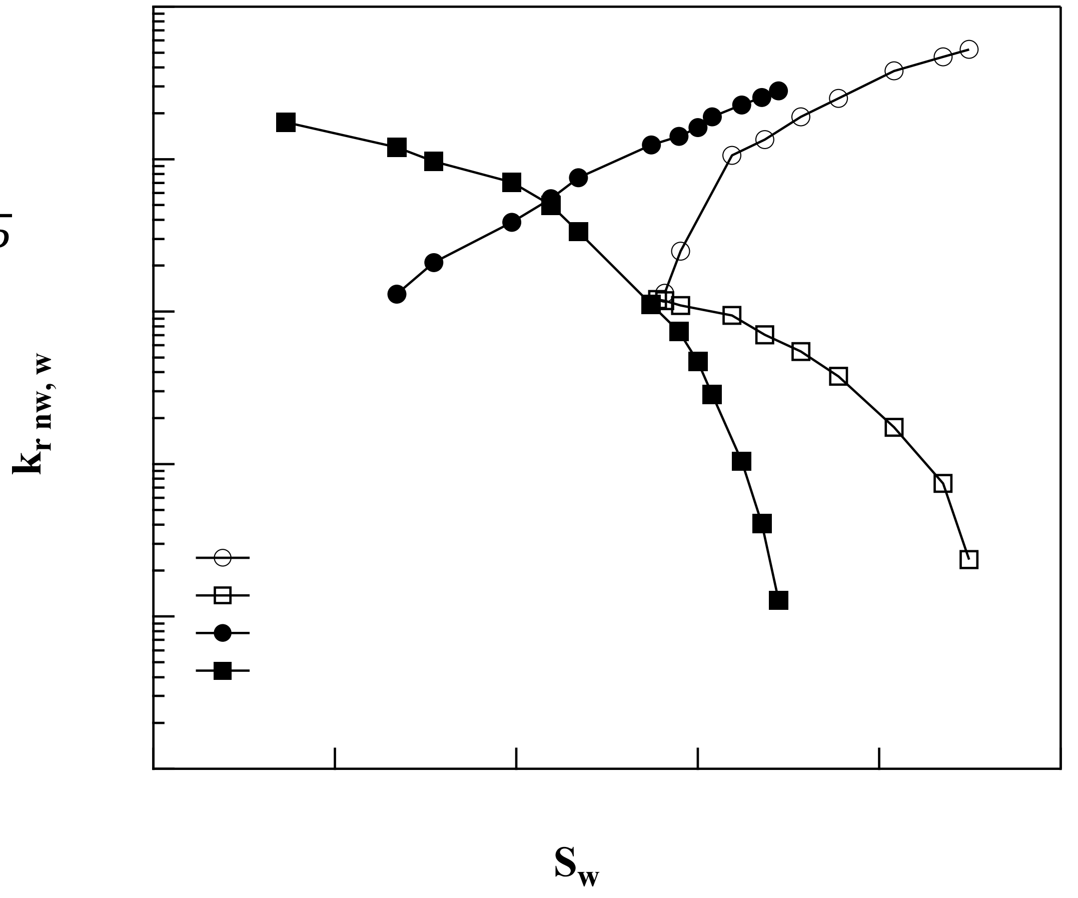


$$N_c = \frac{H}{|\Delta P_c(f_w)|}\frac{\Delta P}{L}$$

Small heterogeneities result in flow rate dependency of relative permeability

$$K = \frac{q\,\mu\,L}{A\,\Delta\,P}$$

$$k_{r,i}(S_i) = \frac{q\,\mu_{\,i}\,L}{A\,K\,\Delta\,P}$$

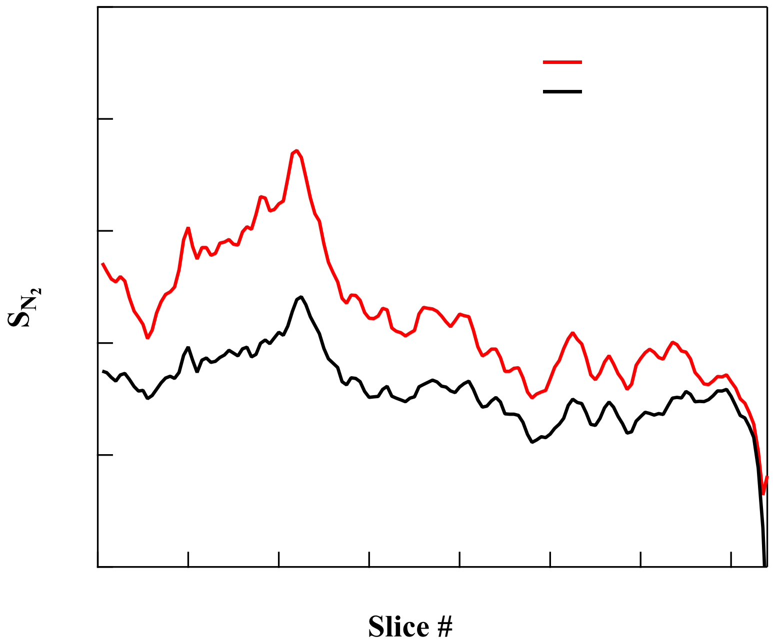


Estaillades

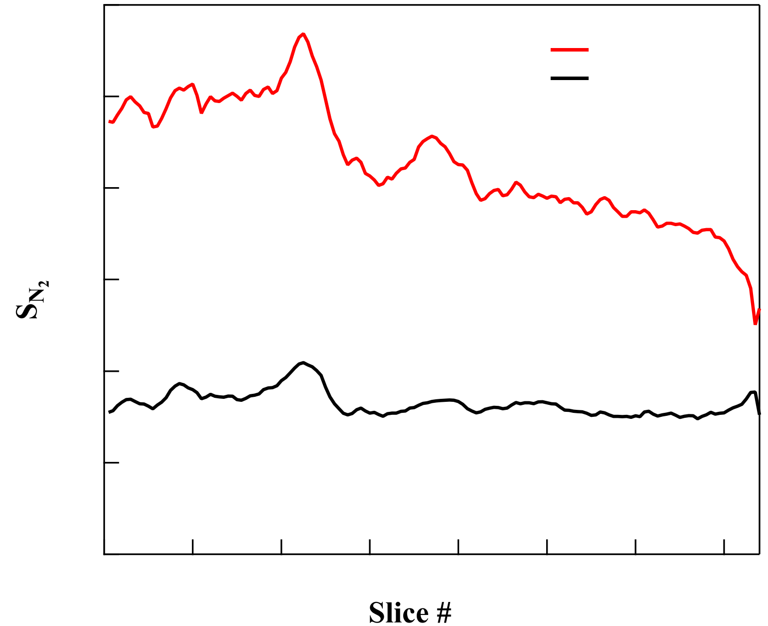
$$S_w = 1 - S_{N2} \qquad S_{N2} = \frac{CT_{exp} - CT_{water}}{CT_{N2} - CT_{water}}$$

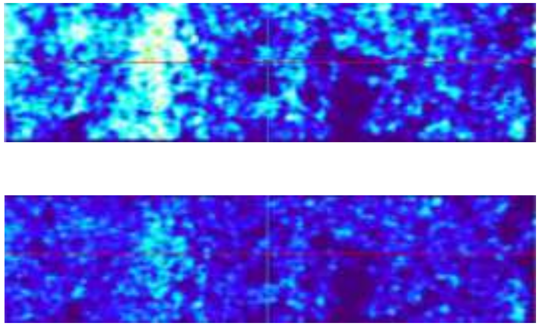
Residual nitrogen saturation increases with heterogeneity

Low flow rate
q_T = 0.5 ml min^{-1}



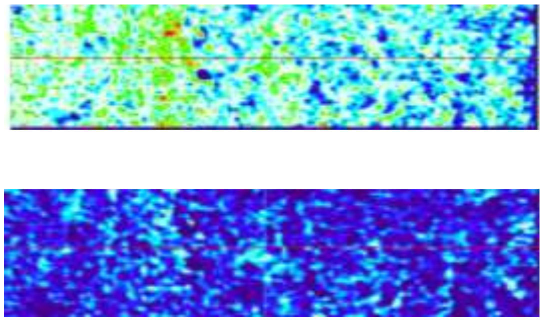
High flow rate
q_T = 20 ml min^{-1}

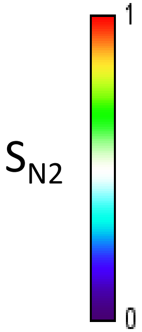




f_{N2} = 1

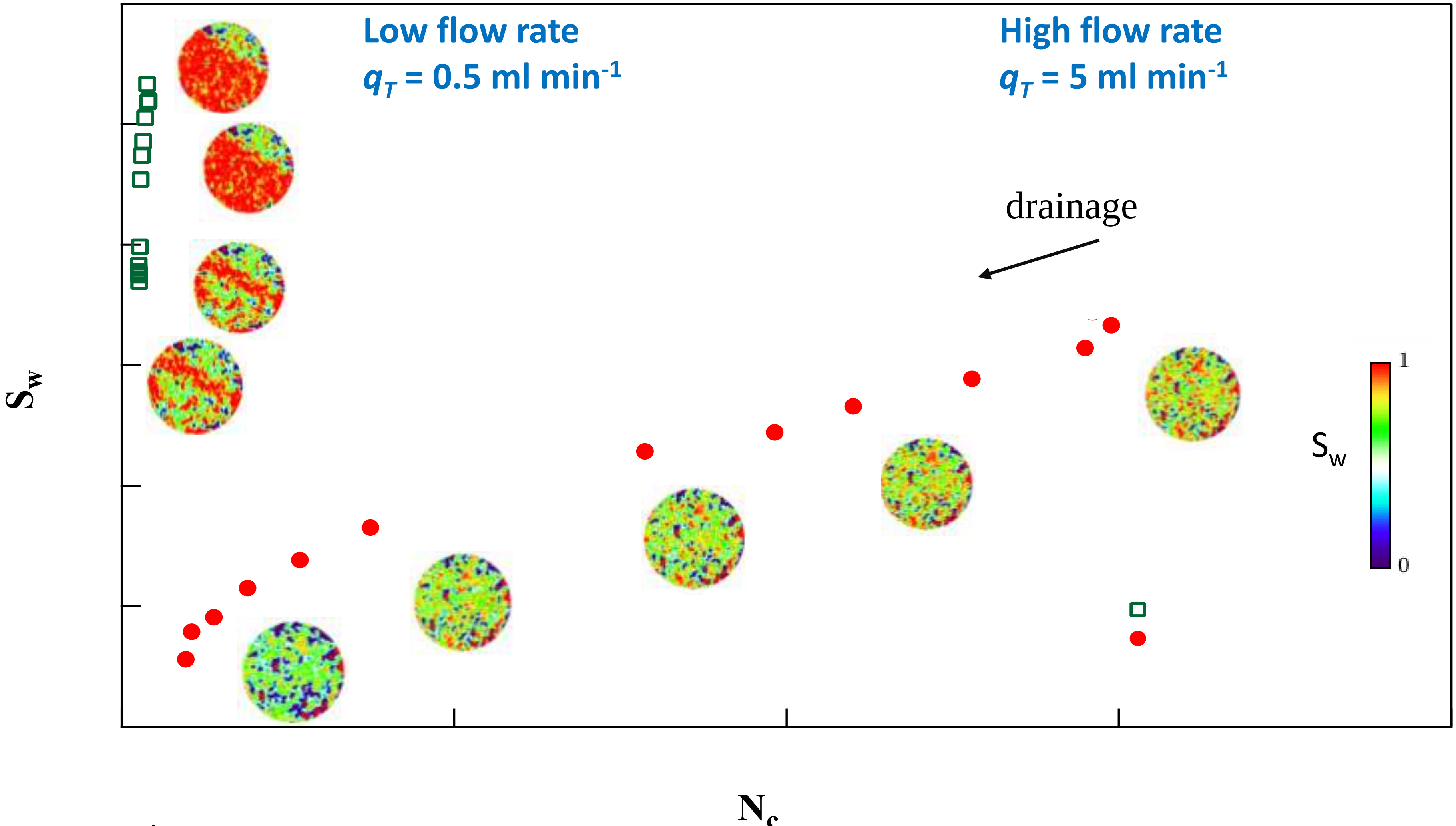
f_{N2} = 0



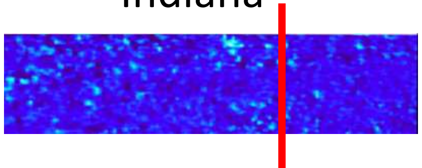


Estaillades

Heterogeneity impacts 3D saturations



Indiana

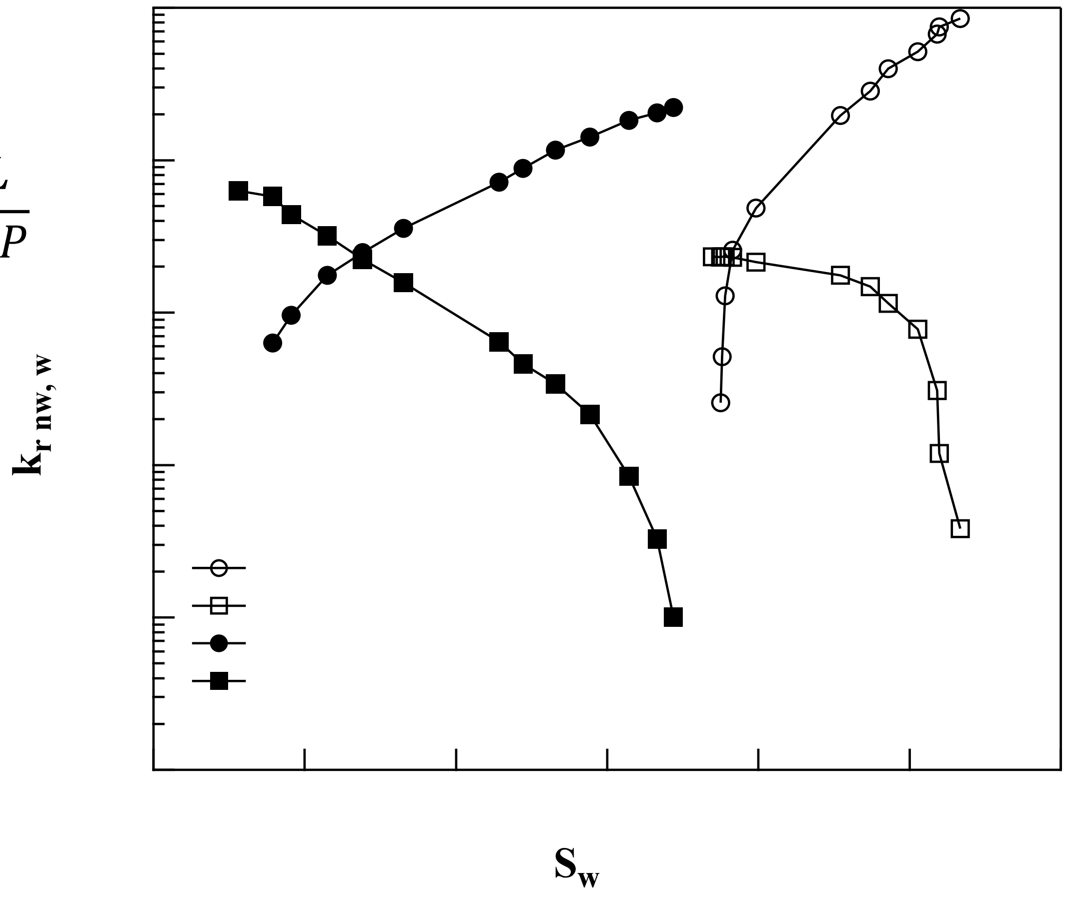


$$N_c = \frac{H}{|\Delta P_c(f_w)|} \frac{\Delta P}{L}$$

Heterogeneity impacts on flow dependence of relative permeability

$$K = \frac{q\,\mu\,L}{A\,\triangle\,P}$$

$$k_{r,i}(S_i) = \frac{q\,\mu_i\,L}{A\,K\,\triangle\,P}$$

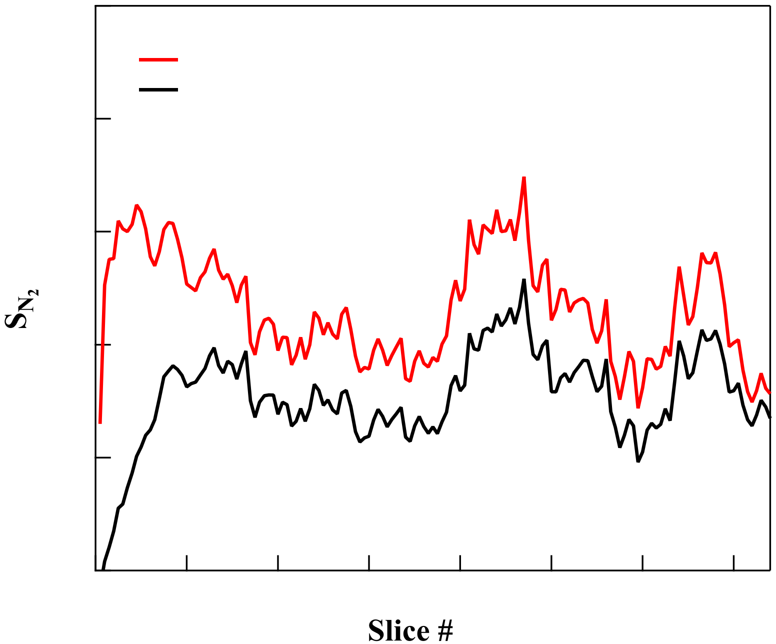


Indiana

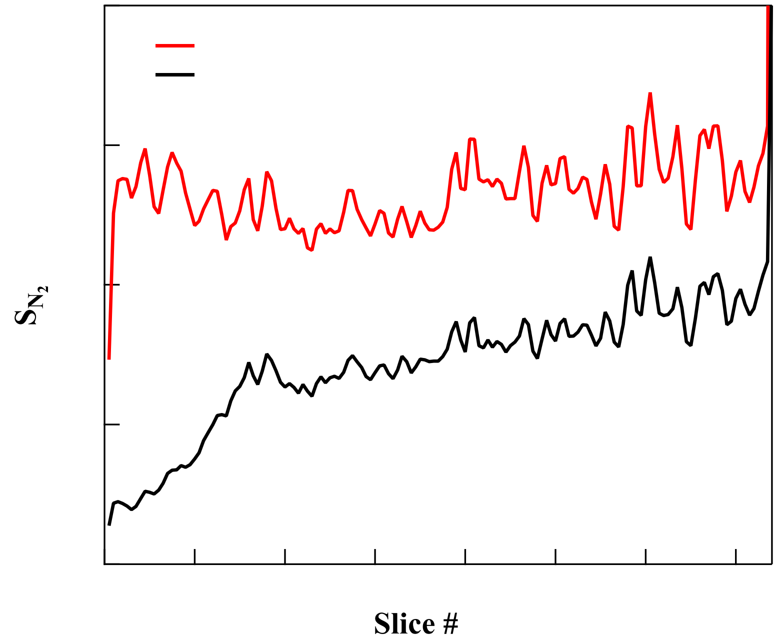
$$S_w = 1 - S_{N2} \qquad S_{N2} = \frac{CT_{exp} - CT_{water}}{CT_{N2} - CT_{water}}$$

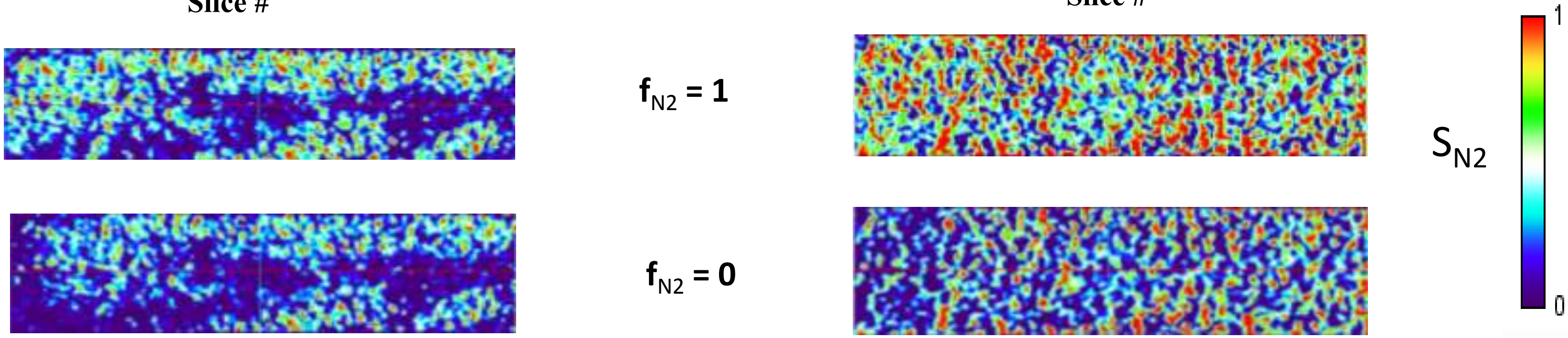
Residual nitrogen saturation increases with heterogeneity

Low flow rate
$q_T = 0.5$ ml min^{-1}



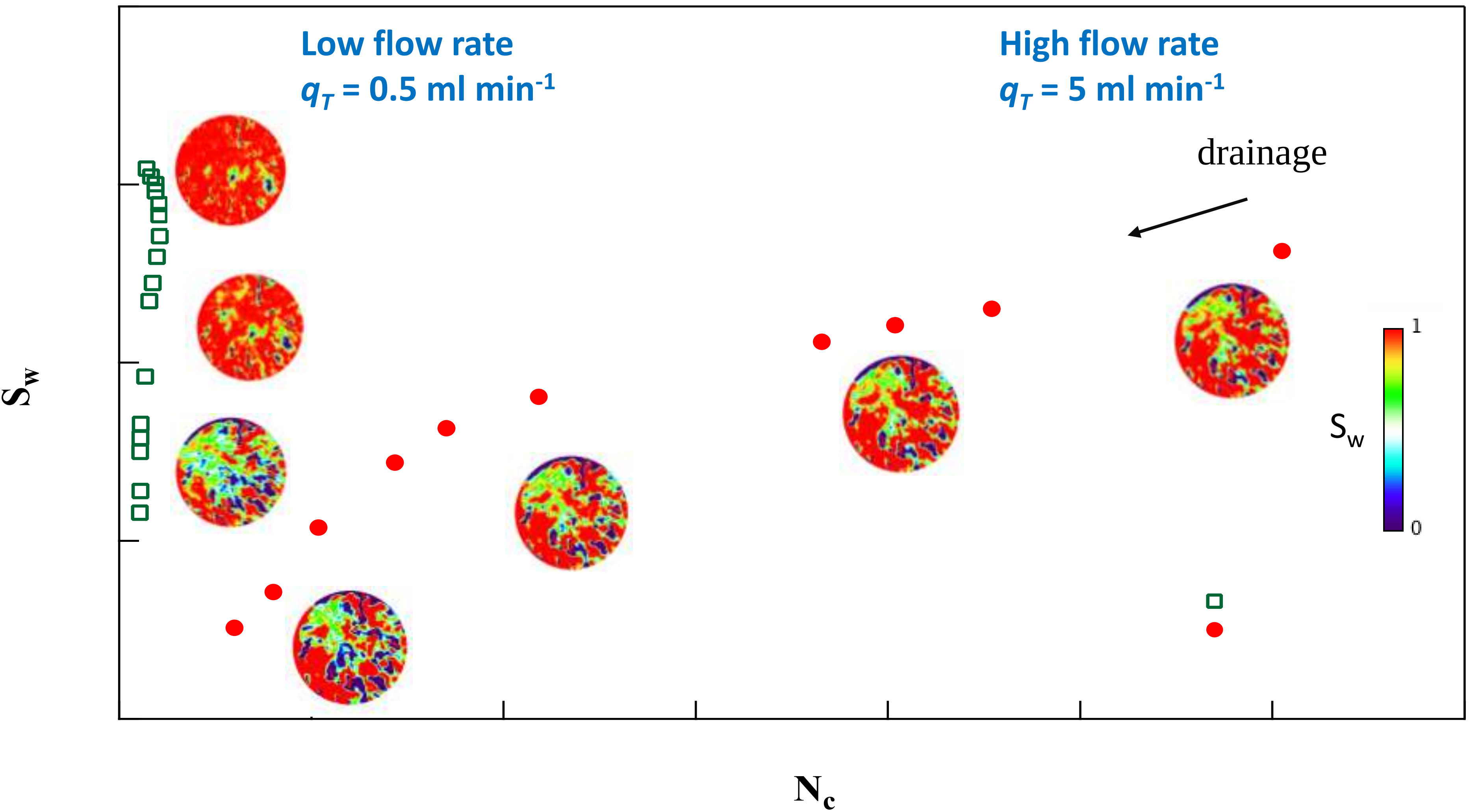
High flow rate
$q_T = 5$ ml min^{-1}



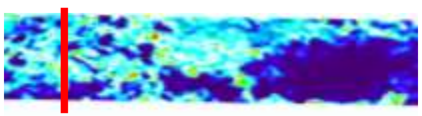


Indiana

Heterogeneity impacts 3D saturations



Edward Brown

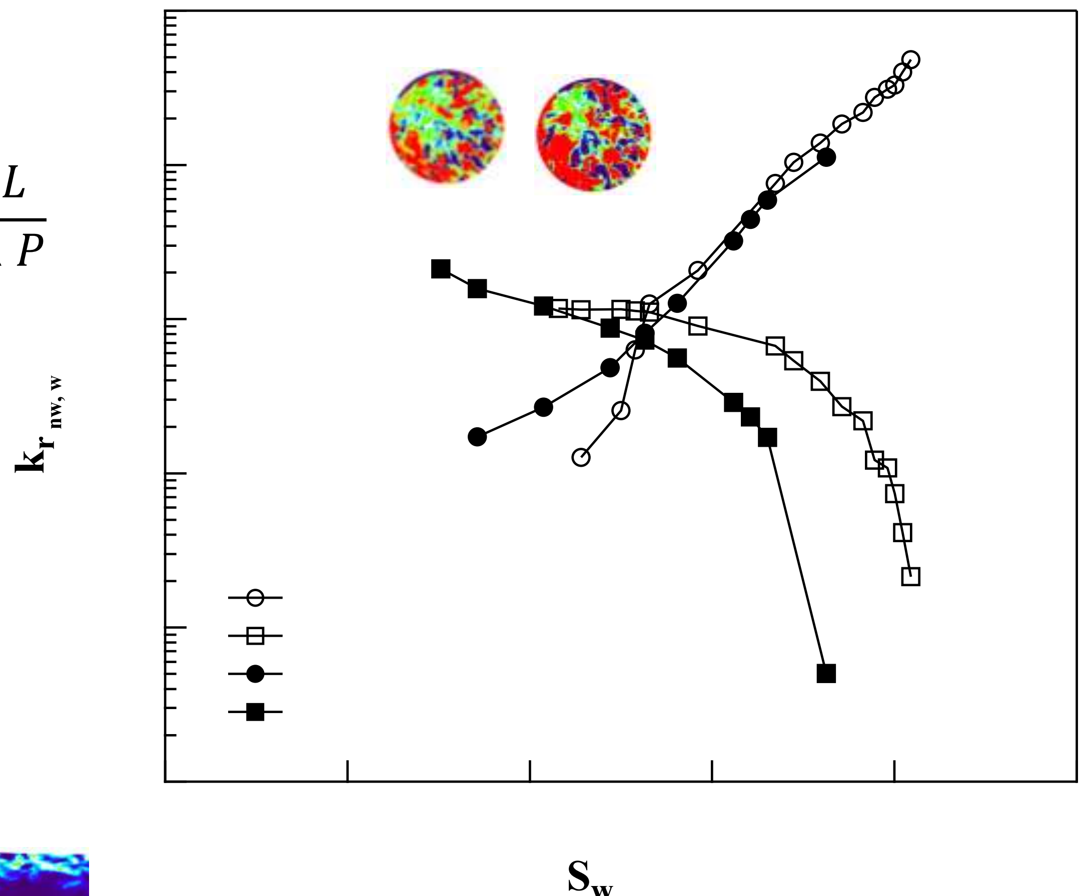


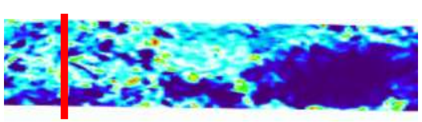
$$N_c = \frac{H}{|\Delta P_c(f_w)|} \frac{\Delta P}{L}$$

Large heterogeneity impacts relative permeability over a range of flow rates

$$K = \frac{q\,\mu\,L}{A\,\Delta\,P}$$

$$k_{r,i}(S_i) = \frac{q\,\mu_{\,i}\,L}{A\,K\,\Delta\,P}$$



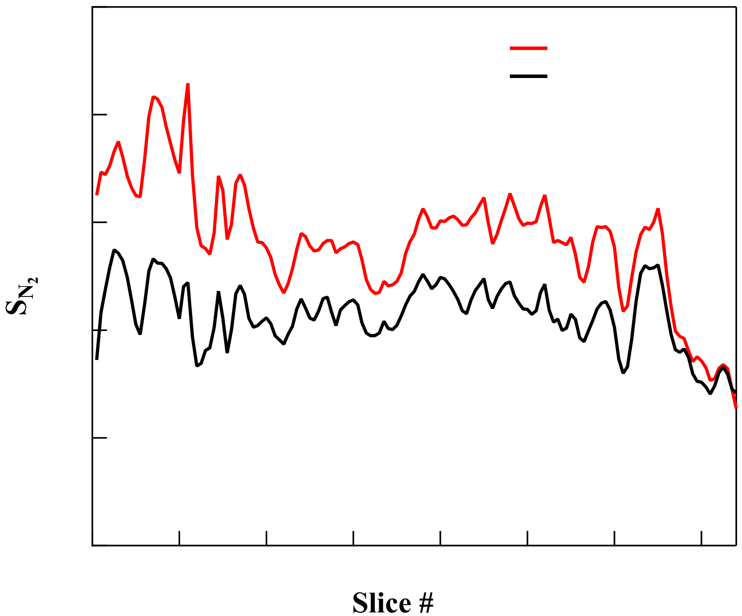


Edward Brown

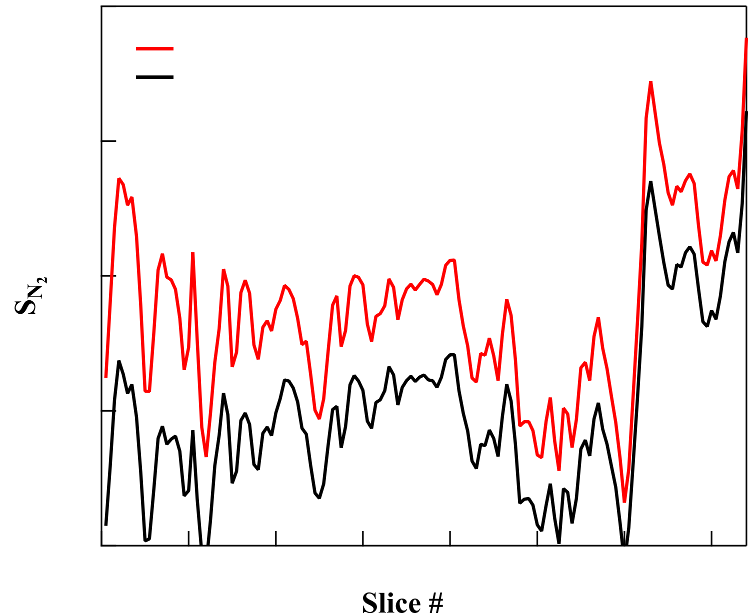
$$S_w = 1 - S_{N2} \qquad S_{N2} = \frac{CT_{exp} - CT_{water}}{CT_{N2} - CT_{water}}$$

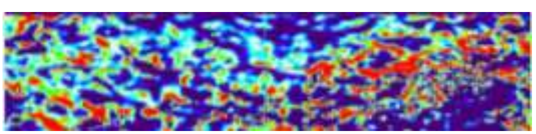
Large heterogeneity near outlet increases trapping upstream

Low flow rate
q_T = 0.5 ml min^{-1}

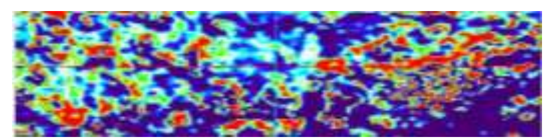


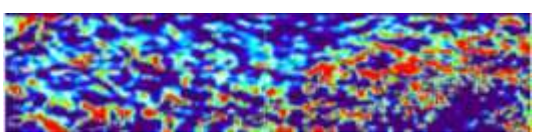
High flow rate
q_T = 5 ml min^{-1}



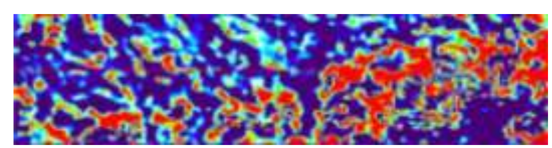


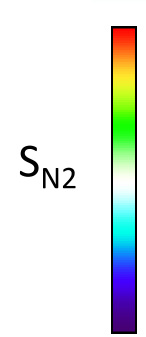
f_{N2} = 1





f_{N2} = 0

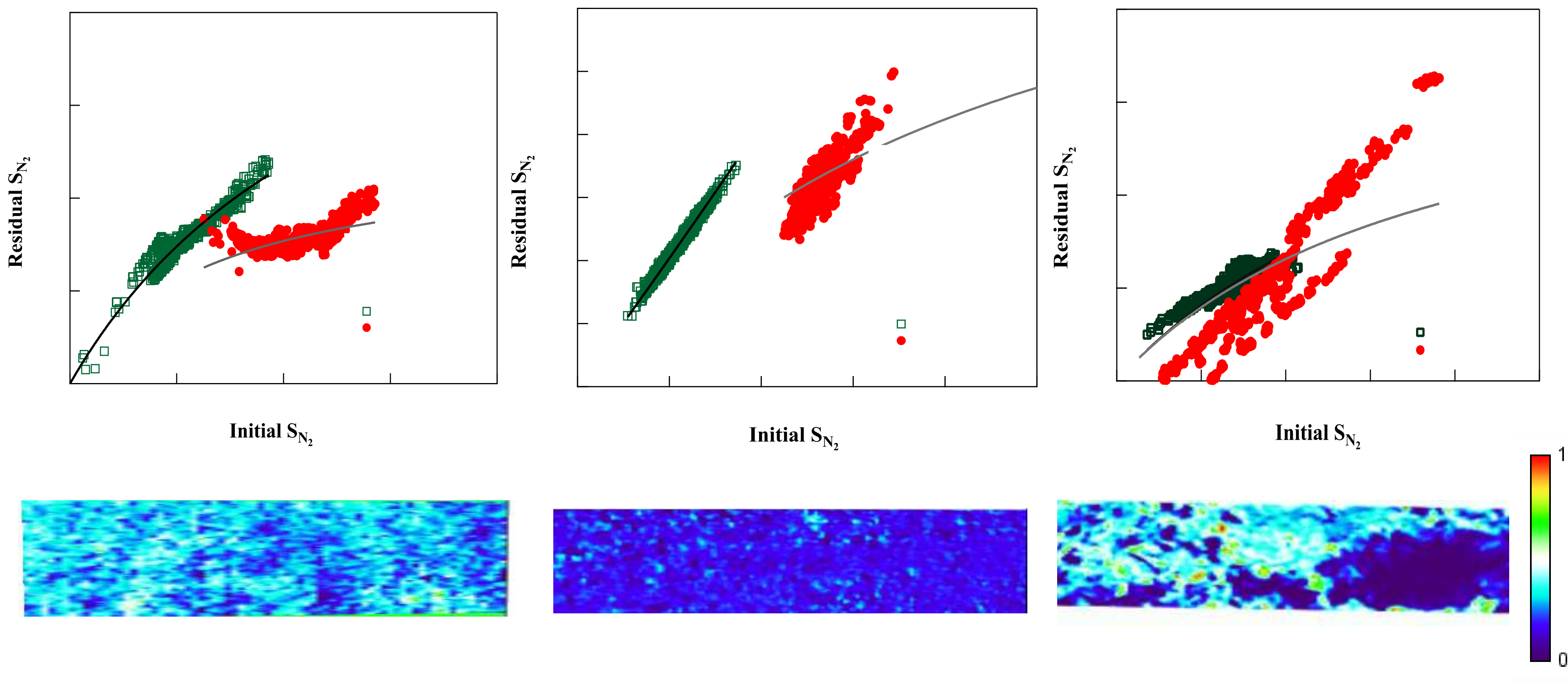




Edward Brown

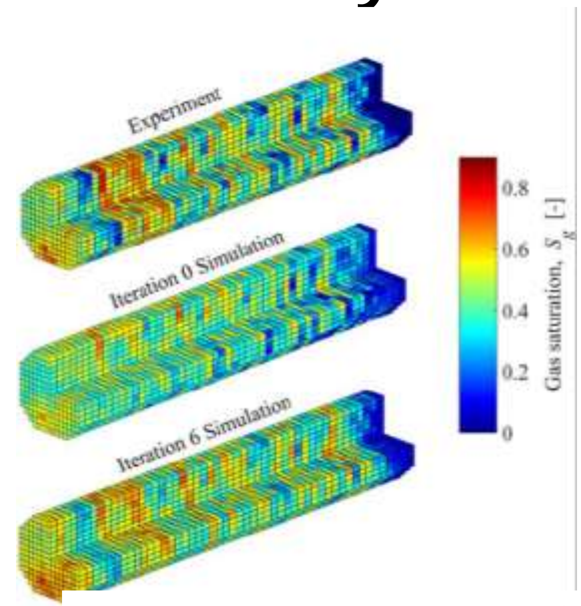
Residual trapping increases with heterogeneity

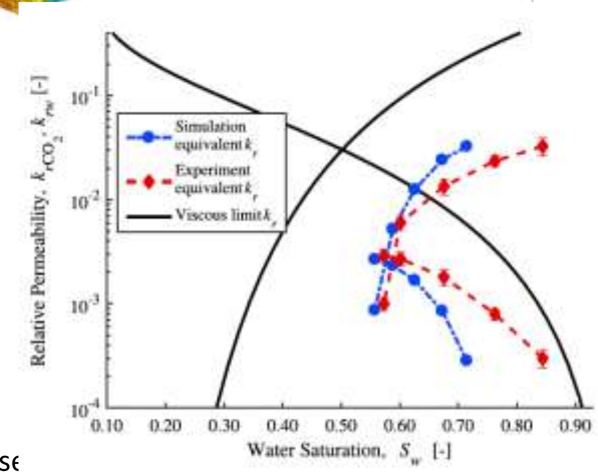
Land curve Fit, $$S_{N2\,r} = \frac{S_{N2\,i}}{1 + C\,S_{N2\,i}}$$



Using observations of heterogeneous rocks to characterise a reservoir system

- Flow properties of heterogeneous rocks cannot be obtained directly from the observations
- Observations can be used to construct a numerical model of a rock core
- The numerical model can be used to estimate an "equivalent", relative permeability at a particular capillary number
- The equivalent relative permeability can be used as the first step in an upscaling workflow





Jackson, S. J., Agada, S., Reynolds, C. A., & Krevor, S. (2018). Characterizing drainage multiphase
Water Resources Research, 54(4), 3139-3161.

Jackson, S. J., & Krevor, S. (2019). Characterization of Hysteretic Multiphase Flow from the MM to M Scale in Heterogeneous Rocks. In E3S Web of Conferences (Vol. 89, p. 02001). EDP Sciences.

Summary

- Multi-scale heterogeneities result in flow-rate dependent relative permeability
- Intrinsic relative permeability does not exist for highly heterogenous cores
- Large heterogeneity increases residual saturation
- These effects must be incorporated into models for accurate field scale models
- We are working on using these observations to parameterise numerical models as a first step in an upscaling workflow

Acknowledgements

- ACT ELEGANCY, Project No 271498, has received funding from DETEC (CH), FZJ/PtJ (DE), RVO (NL), Gassnova (NO), BEIS (UK), Gassco AS, Equinor and Total, and Statoil Petroleum AS, and is co-funded by the European Commission under the Horizon 2020 programme, ACT Grant Agreement No 691712.

Background

- Relative permeability :

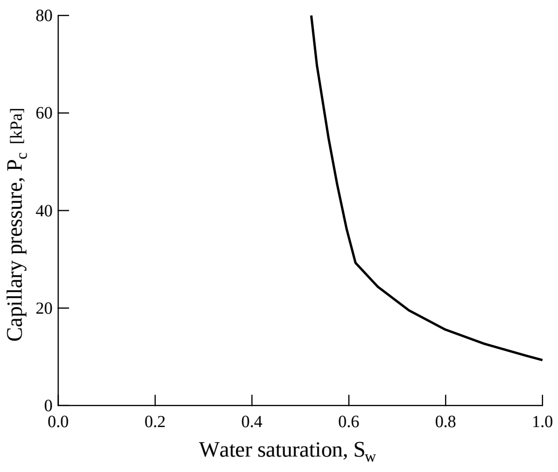
Darcy law for single-phase flow, $q = -\frac{K}{\mu}\left(\nabla P - \rho g \right)$

for multiphase flow, $q_i = -\frac{k_i K}{\mu_i}\left(\nabla P - \rho_i g \right)$

$k_i(S_w)$

- Capillary Pressure :

$$P_c = P_{nc} - P_c = \sigma \frac{dA}{dV}$$

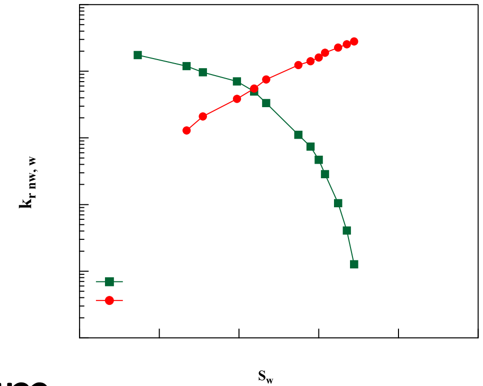


$P_c\,(x, y, z, S_w)$

Numerical modeling workflow

Goals

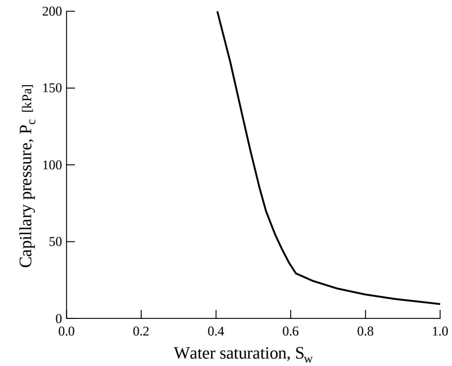
- Calibrate a predictive digital model
- Perform numerical core floods to obtain appropriate equivalent property



Needed for numerical model

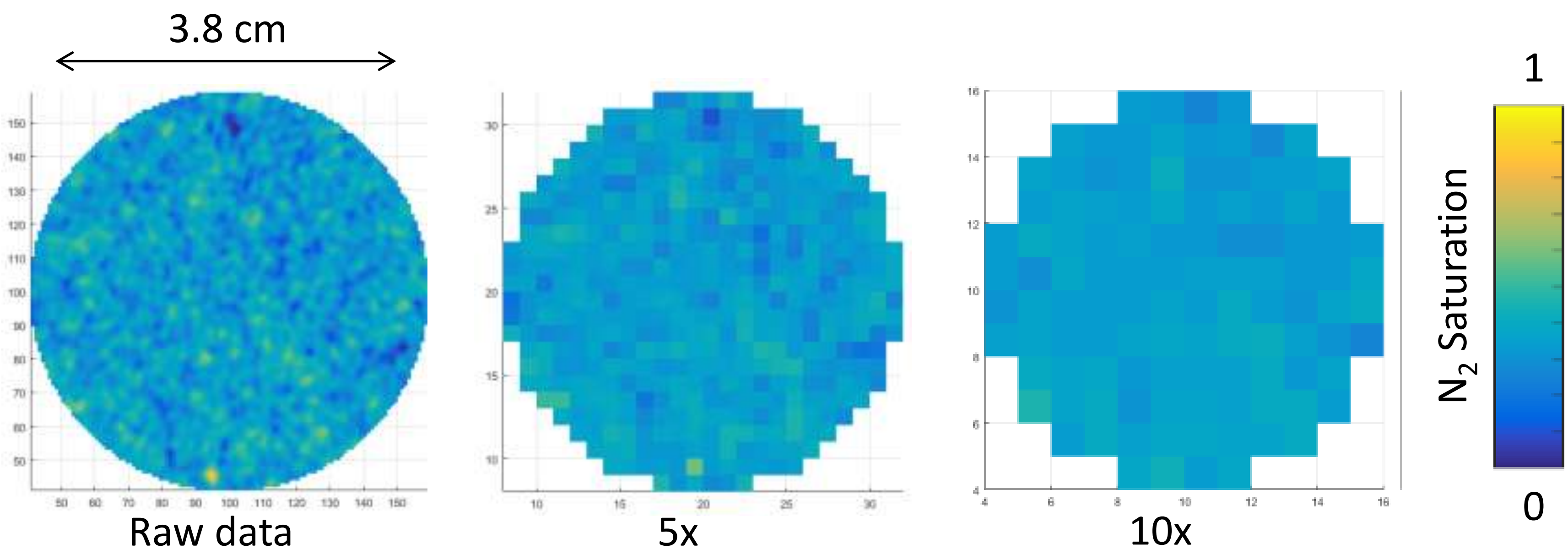
- Routine properties : Porosity, permeability
- Intrinsic SCAL properties : high flow rate rel perm
- Capillary heterogeneity : MICP and 3D saturation maps

$$P_c\,(x, y, z, S_w) = k\,P_{c,\,a}(S_w)$$



Capillary heterogeneity is inferred from the 3D saturation maps

Data was coarsened to improve precision

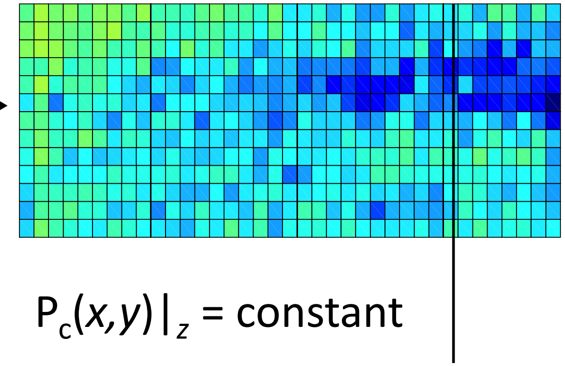


$P_c\ (x, y, z, Sw) = k\ P_{c,\,a}(Sw)$

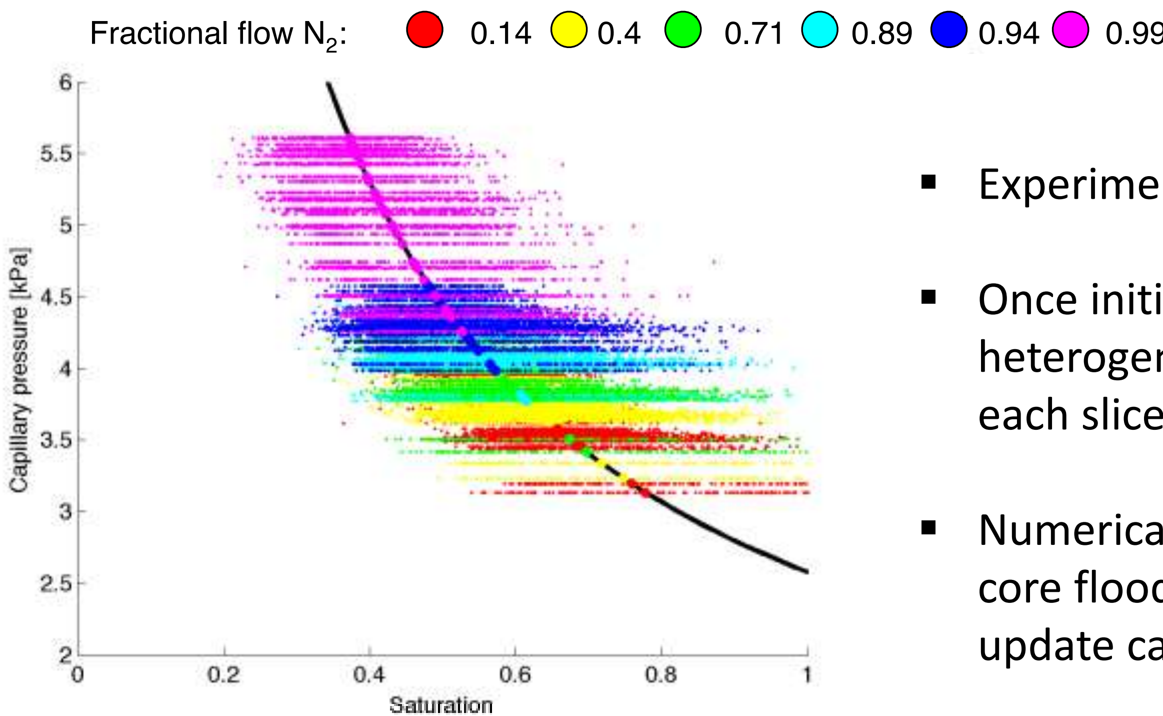
Extract individual voxel P_c curves

First guess assumes P_c in a slice is given by the average slice saturation

Flow *z*-direction

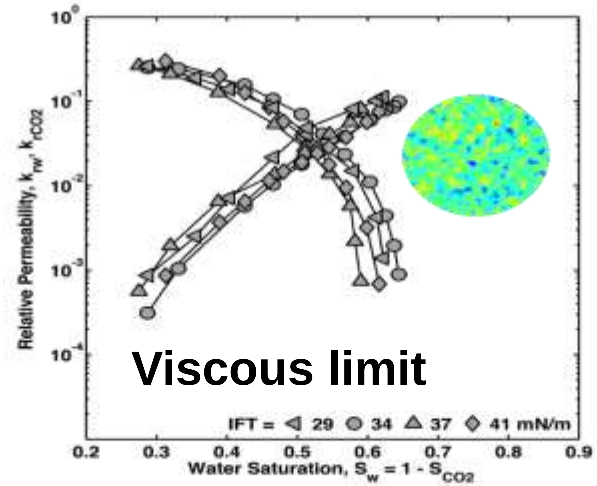


$P_c(x,y)|_z$ = constant



- Experimental 3D map of k is obtained
- Once initial estimation of Pc heterogeneity is obtained, constant Pc in each slice assumption is relaxed
- Numerical simulation of low flow rate core flood experiments is performed to update capillary pressure heterogeneity.

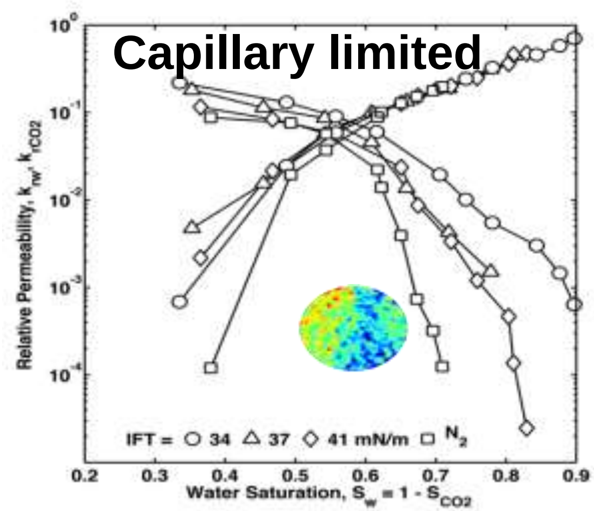
Flow rate dependence of relative permeability depends on heterogeneity, but heterogeneity depends on driving potential for flow



$$\nabla \cdot (-\lambda_T \nabla P_{CO_2} + \lambda_w \nabla P_c) = 0$$

Viscous flow **Capillary distribution**

If the flow potential is large relative to gradients in capillary pressure:
Viscous limit, homogenous saturation, invariant rel. perm



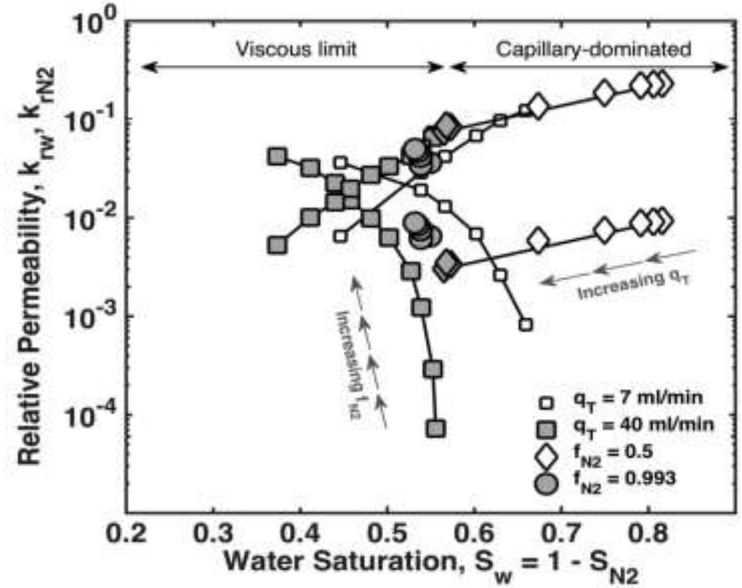
If the flow potential is not large relative to gradients in capillary pressure:
Effects of capillarity, heterogeneous saturation, “effective” flow dependent relative permeability

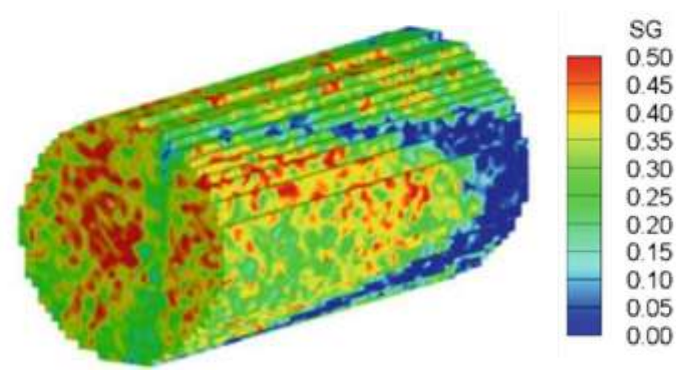
Goals

1. Calibrate a predictive digital model
2. Perform numerical core floods to obtain appropriate equivalent property

Needed for numerical model

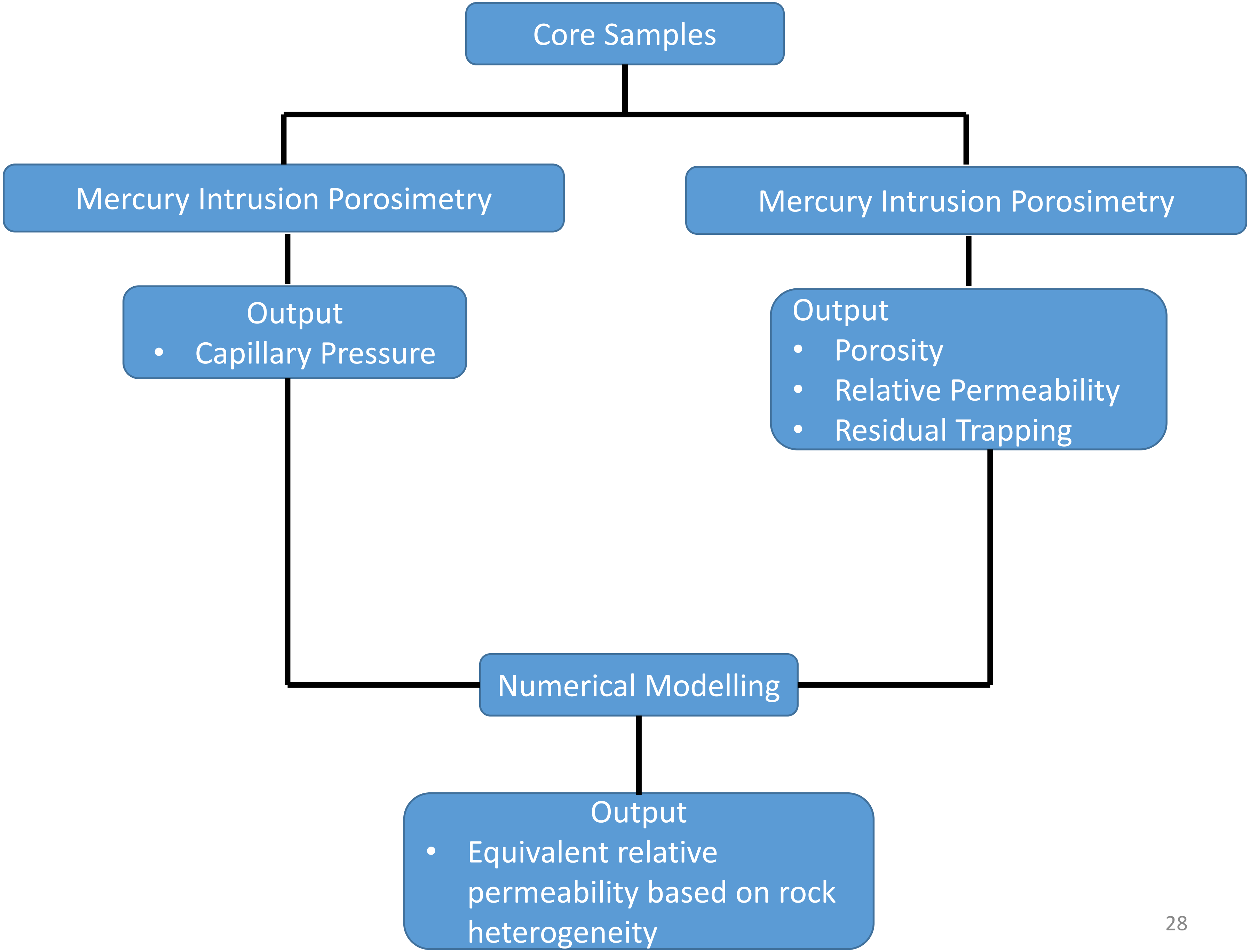
1. Routine properties
2. Intrinsic SCAL properties
3. Capillary heterogeneity





Experimental Conditions

Sample	Temperature (^0C)	Pressure (MPa)	Type	Total flow rate (ml/min)
Estaillades	20	10	Drainage	0.5
			Trapping	0.5
			Drainage	20
			Trapping	20
Indiana	20	10	Drainage	0.5
			Trapping	0.5
			Drainage	5
			Trapping	5
Edward Brown	20	10	Drainage	0.5
			Trapping	0.5
			Drainage	5
			Trapping	5


Core Samples
Mercury Intrusion Porosimetry
Mercury Intrusion Porosimetry
Output
• Capillary Pressure
Output
• Porosity
• Relative Permeability
• Residual Trapping
Numerical Modelling
Output
• Equivalent relative permeability based on rock heterogeneity