Gas and Liquid Flow in Shale*

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Abstract

Shale gas strata, important energy supplies in North America, are projected to become important as well in Europe, Latin America, and Asia in the near future. Gas and oil production from these fine-grained reservoirs is technically challenging, however fluid flow as observed in field is much higher than predictions based on conventional models (Darcy's equation). Clear understanding of gas/liquid flow in these natural, fine-grained, porous systems is necessary in making capital investments, as well as in making field-development decisions by governments and major oil companies. This talk presents detailed discussion of gas and liquid flow in tiny pores (nanometer scale). Novel research methods and challenges for reserve estimation and permeability predictions will also be presented.

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Gas and Liquid Flow in Shale

Farzam Javadpour

11/03/2015

Unconventional Update
AAPG Geoscience Technology Workshop

Outline

- Brief introduction of nanophysics
- Shale system
  - Gas-in-place and transport
    - Diffusion in kerogenic material
    - Lost gas
    - Stochastic permeability model
  - In-situ gas chromatography separation
  - Liquid flow and fracture fluid loss

What is nanoscience?

Nano refers to one-billionth of something (10^{-9})

e.g., nanograms, nanoliters, nanometers

Diameter of a hair string: 75,000 nm

Pores in sandstone: 50,000 nm

Red blood cell: 7,000 nm

Pores in shale: 10 nm

Water molecule: 0.3 nm

Nanoscience is the study of structures and materials on the scale of nanometers.
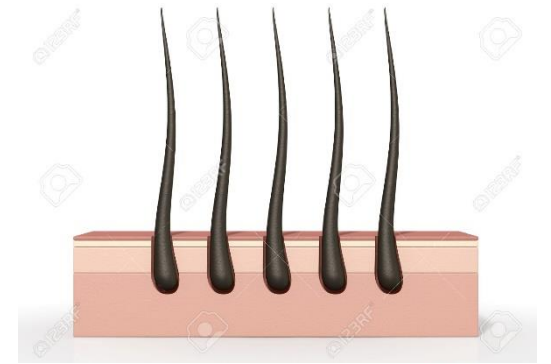
Nanoscale research needs

- Sophisticated measuring devices
- Deep understanding of fundamental physics. Different from continuum physics

Applications & our interest

Natural nanosystems
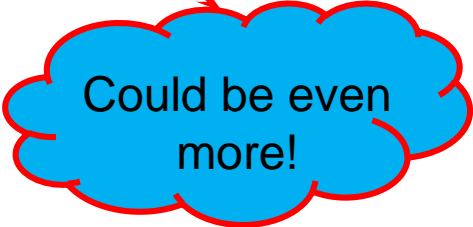
Shale plays

Applications in shale plays
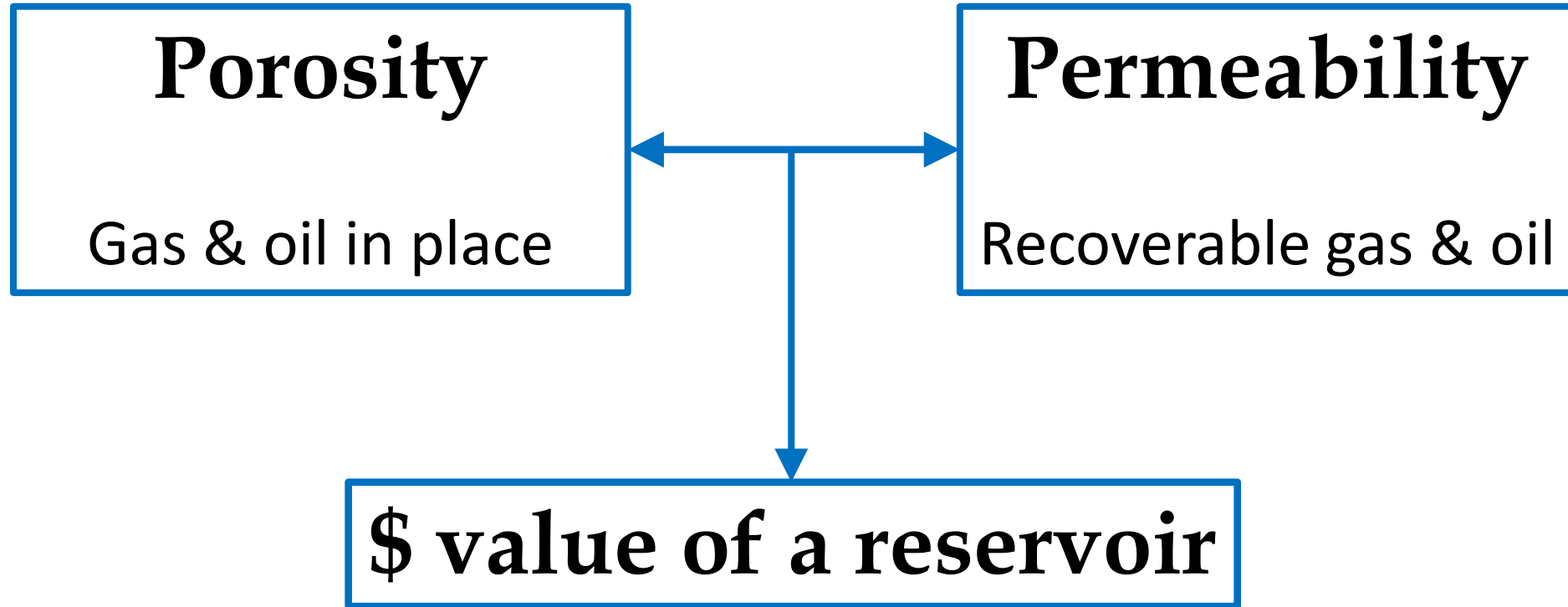
Shale porosity

Pores are at nanoscale

Direct methods

SEM

Poorly Aligned OM Pores

200 nm
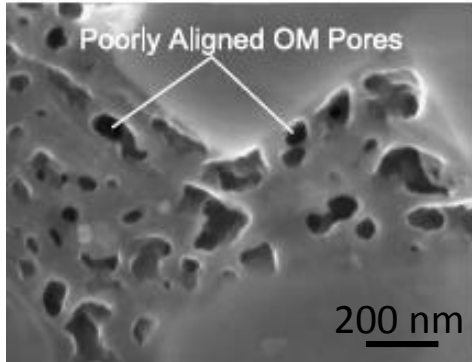
(Loucks et al., AAPG, 2012)

AFM

100 nm
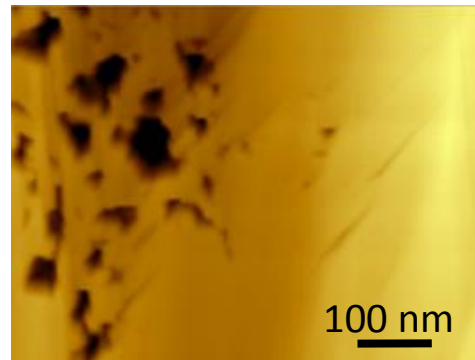
(Javadpour et al, JCPT, 2012)

Indirect methods

MICP tests

1: Shale I (~50 nD)
2: Shale II (~300 nD)
3: Shale III (~700 nD)
4: Crossfield Cardium Sand (230 µD)
5: Indiana Limestone (4,000 µD)
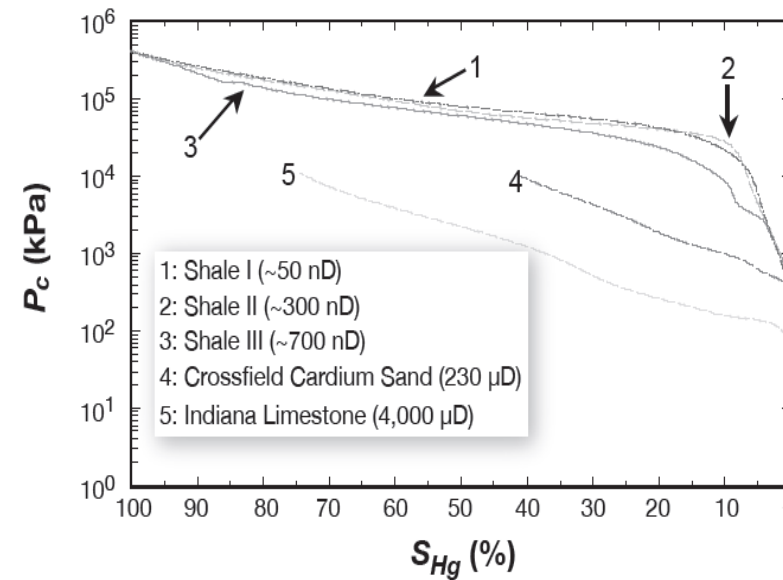
(Javadpour et al., JCPT, 2007)

Nitrogen tests

Pore dia. (nm)	Fraction (%)
5.0	11.5
7.5	16.0
12.5	10.5
17.5	12.0
22.5	7.0
27.5	8.0
32.5	4.0
170.0	31.0

(Courtesy Dr. Zhang)
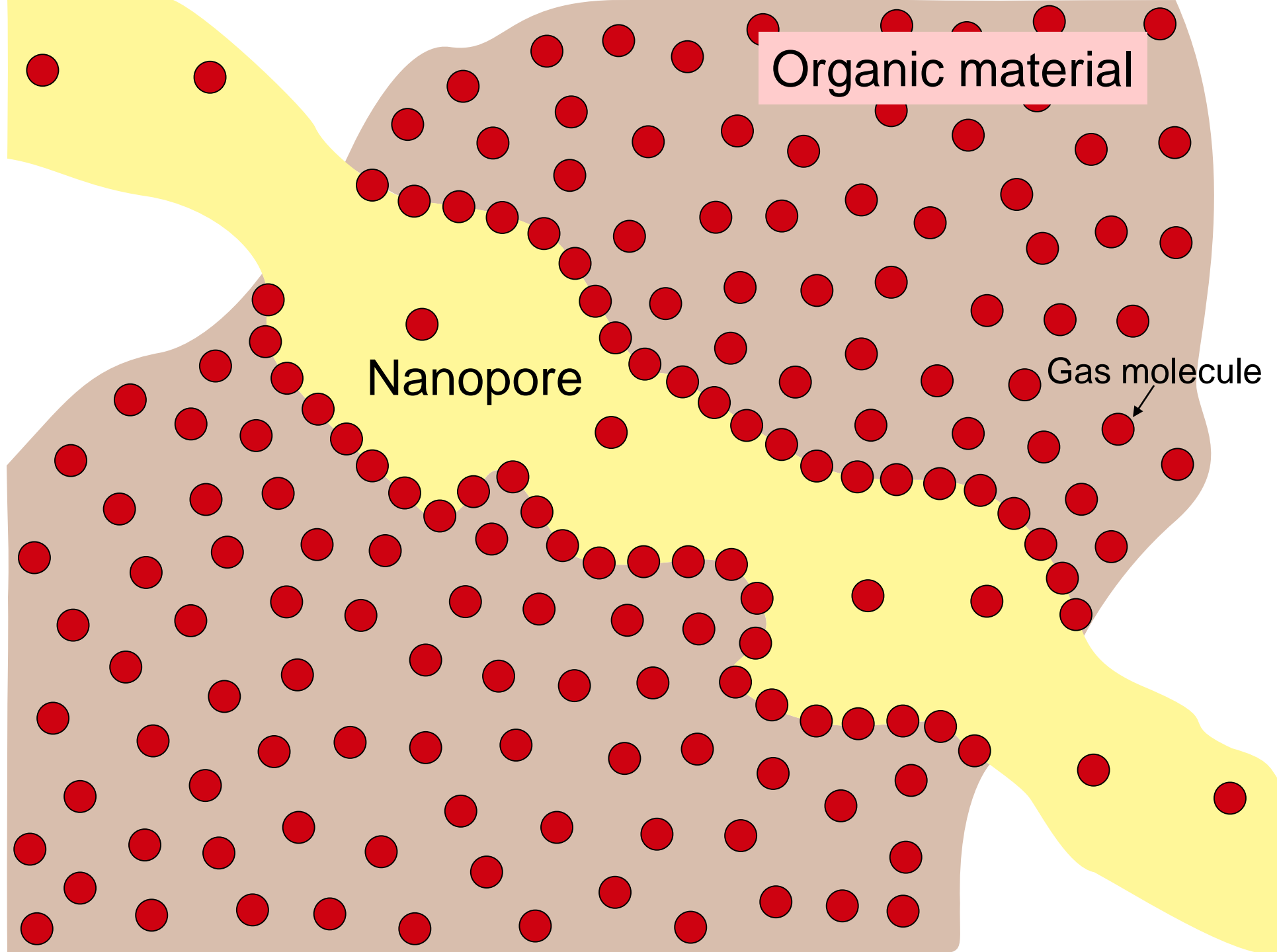
Organic material

Nanopore

Gas molecule

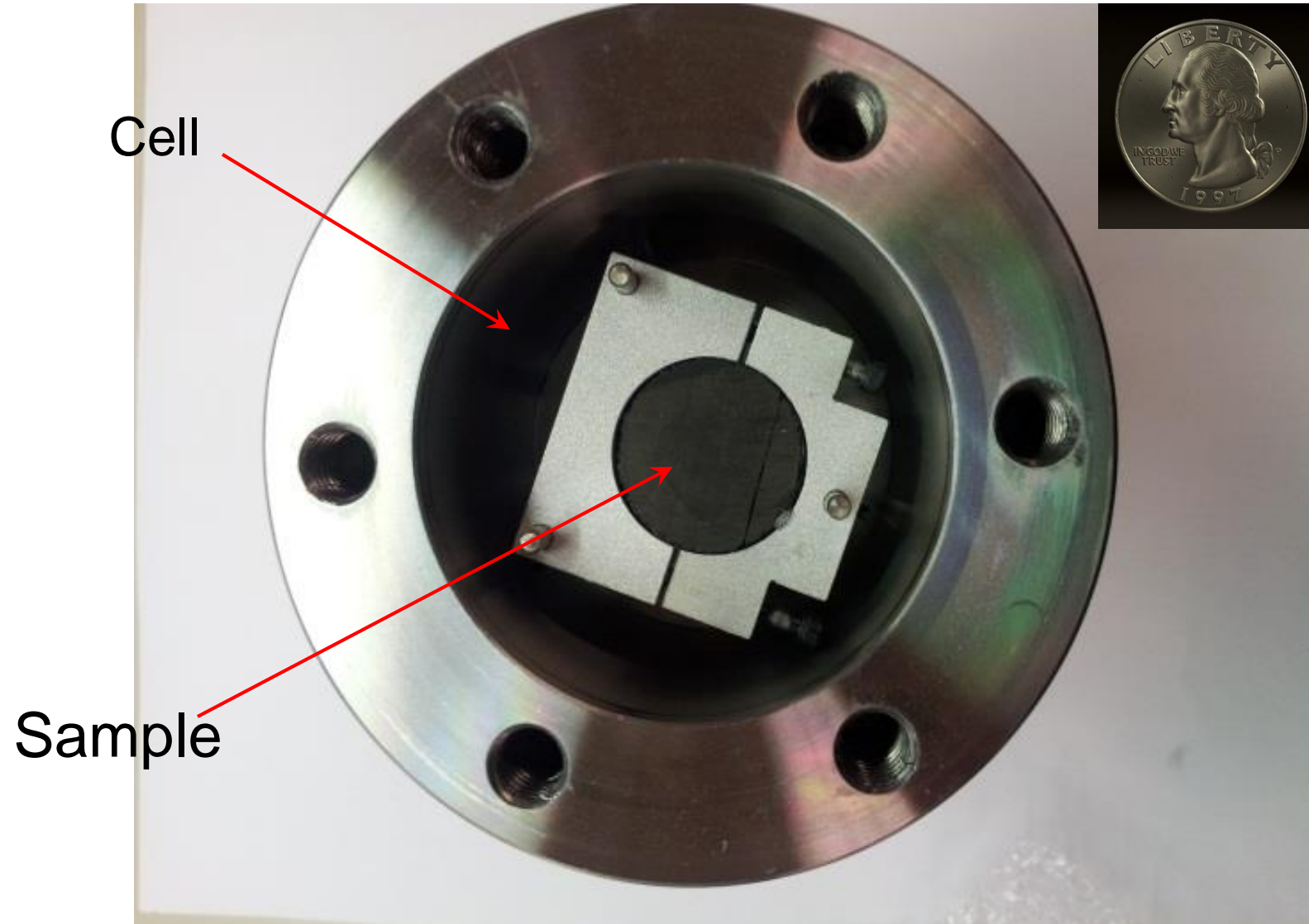# Total gas stored in shale gas strata

$$G_{st} = G_s + G_{cf} + G_{sd}$$

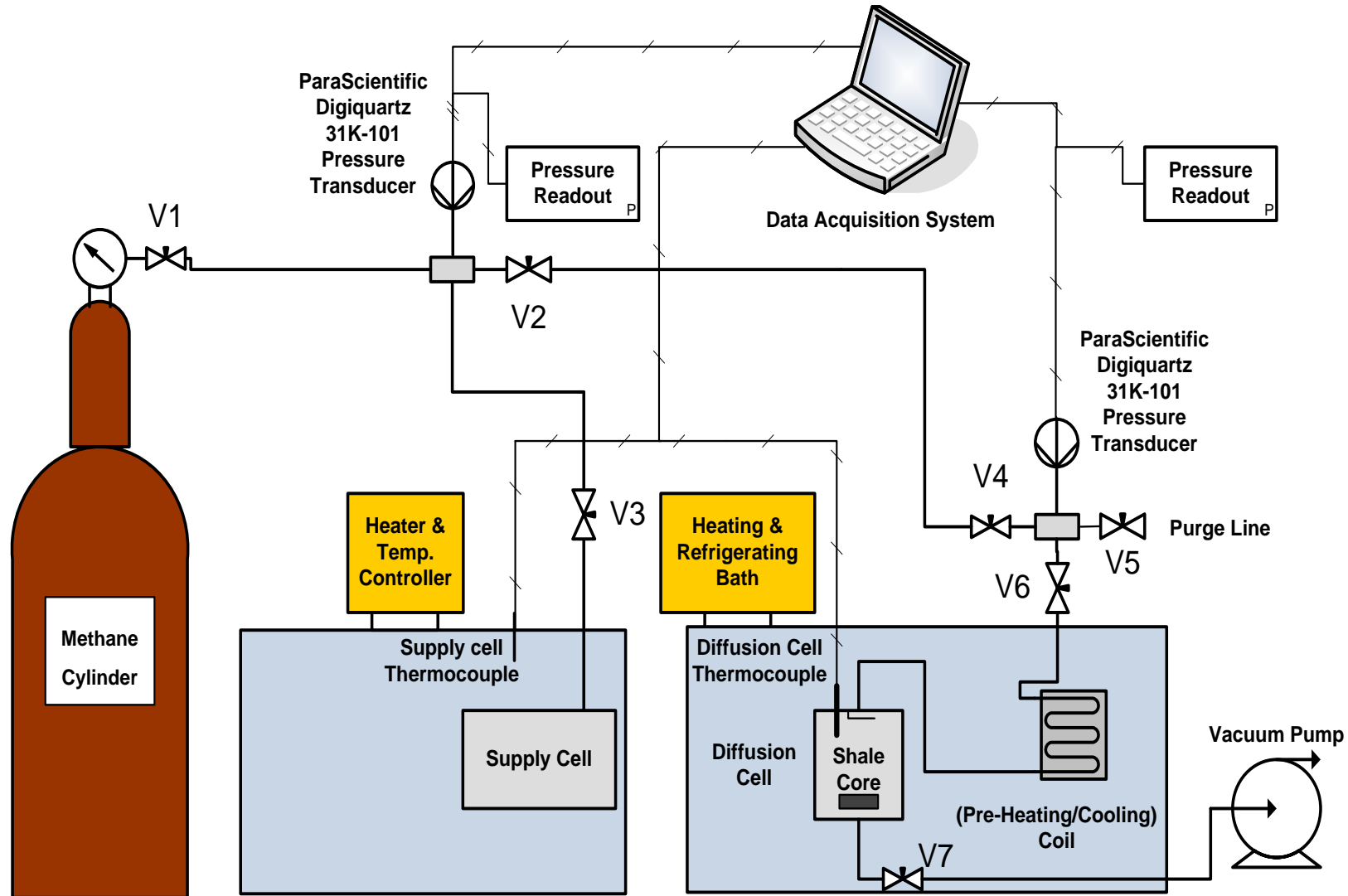| Total gas storage capacity	=	Sorbed gas storage capacity	+	Free gas storage capacity	+	Diffused gas storage capacity
		Geochemistry labs		Routine reservoir engineering analysis		?
		✓		✓		
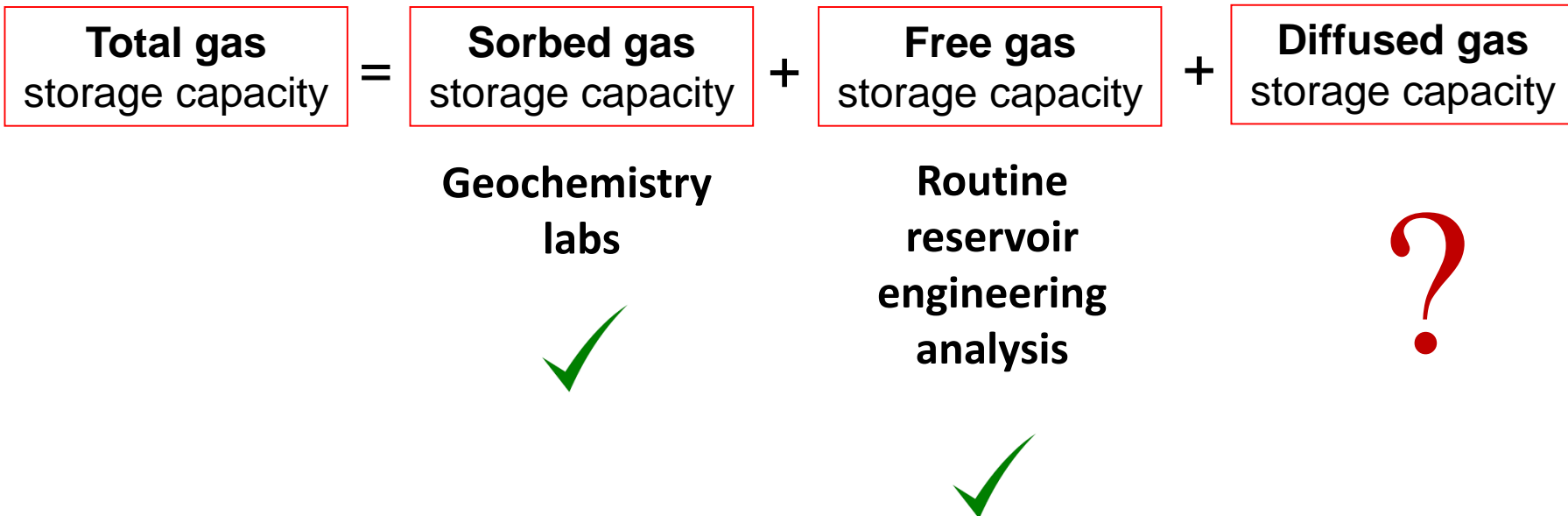
Diffusion in kerogenic material

Diffused gas in bulk kerogen
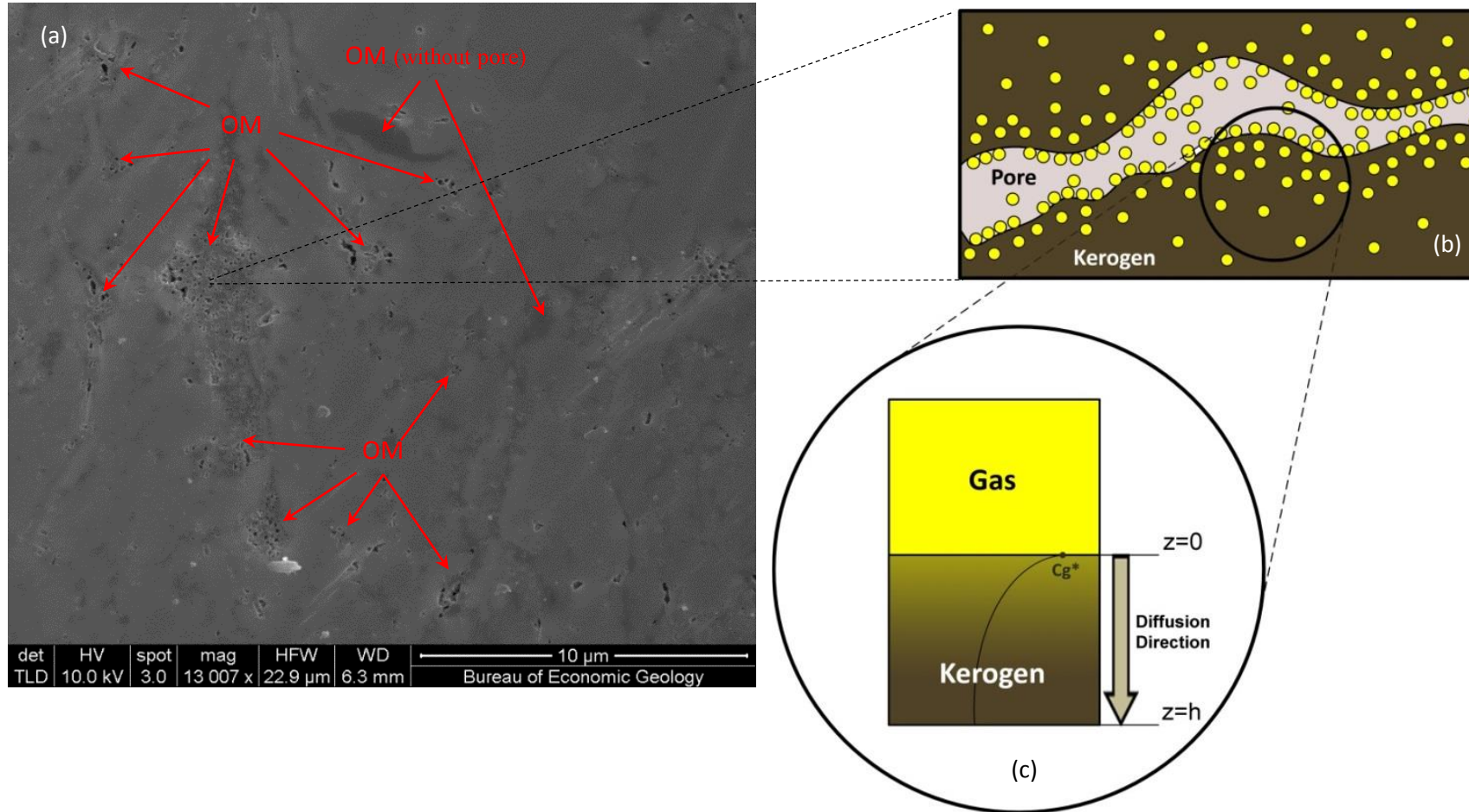
Pressure cell and sample

High precision pressure cell

Conversion of pressure data to mass
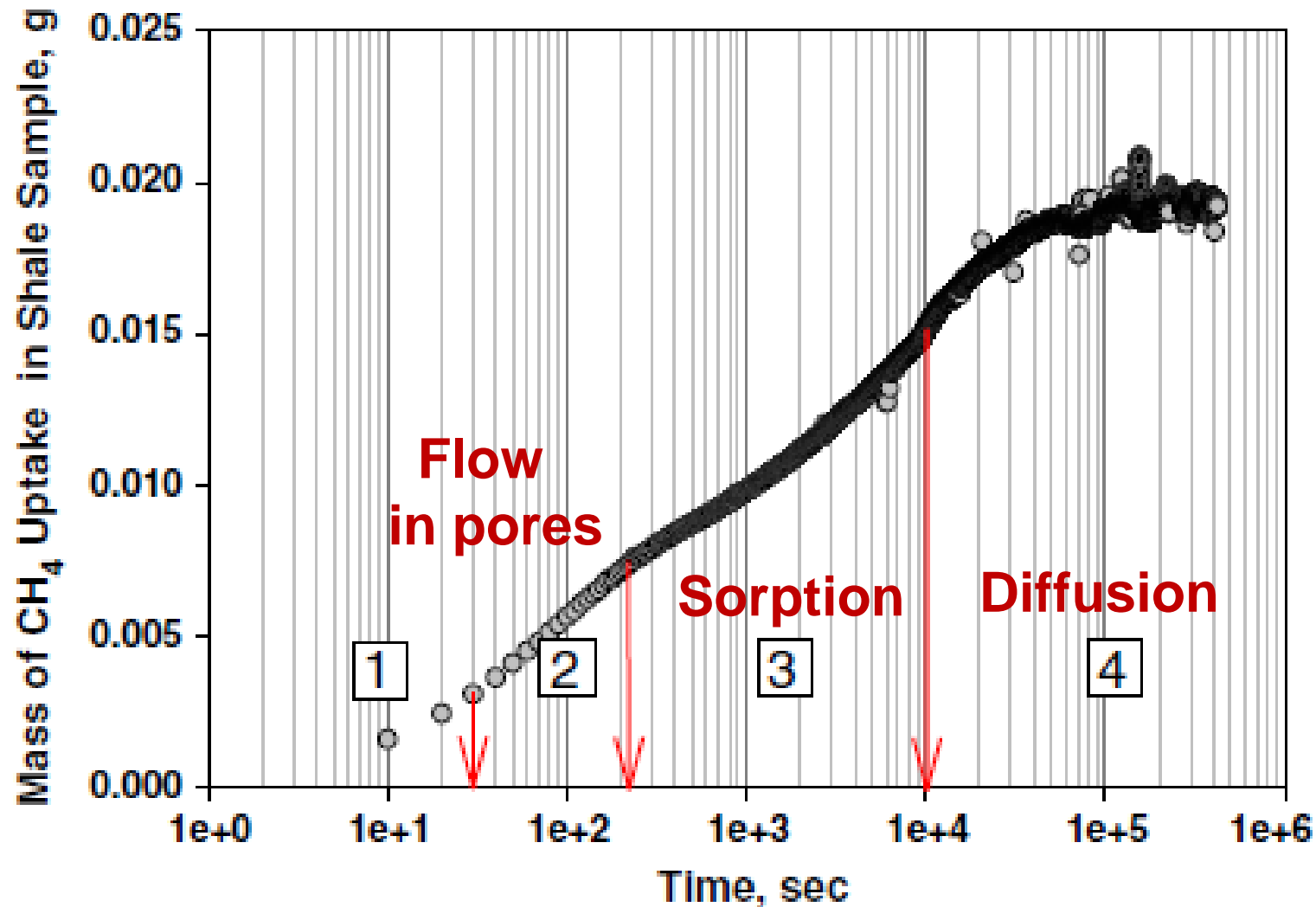
Etminan et al., *International Journal of Coal Geology (2014)*

Gas flow in nanopores

Different flow regimes as a function of Knudsen number.

Knudsen number (K_n)		Flow regime
Lower bound	**Upper bound**	
0	10^{-3}	**Continuum/Darcy flow (No-slip flow)**
10^{-3}	10^{-2}	**Slip flow**
10^{-2}	10^{-1}	
10^{-1}	10^{0}	**Transition flow**
10^{0}	10^{1}	
10^{1}	∞	**Free-molecule flow**

Validity of the LSP model

Navier-Stokes Equation
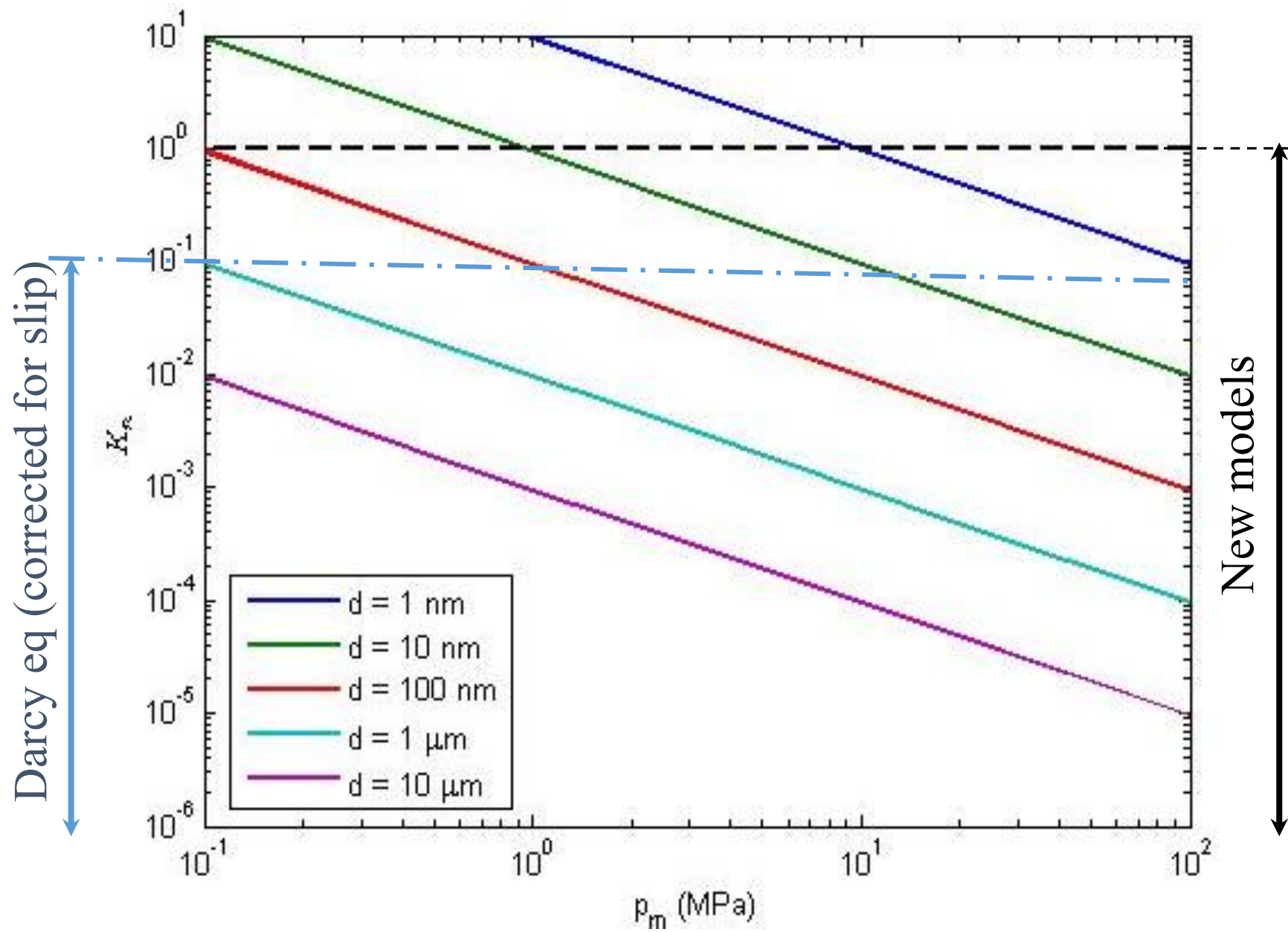
Apparent permeability of nanopores

$$k_{app} = \frac{2r\mu M}{3 \times 10^3 RT\rho_{avg}} \left(\frac{8RT}{\pi M} \right)^{0.5} + F\frac{r^2}{8}$$

$$F = 1 + \left(\frac{8\pi RT}{M} \right)^{0.5} \frac{\mu}{p_{avg}r} \left(\frac{2}{\alpha} - 1 \right)$$
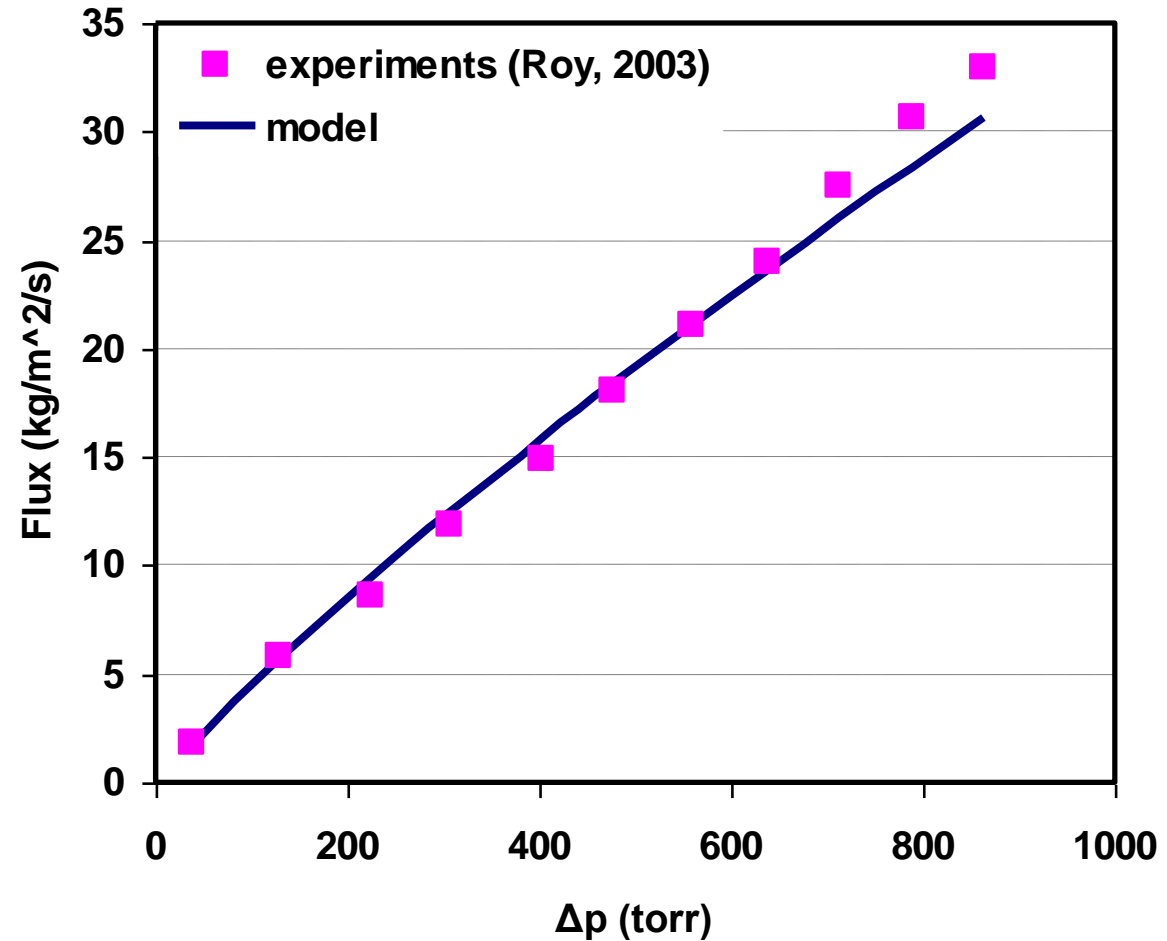
Compare to Darcy eq.

$$k_{Darcy} = \frac{r^2}{8}$$
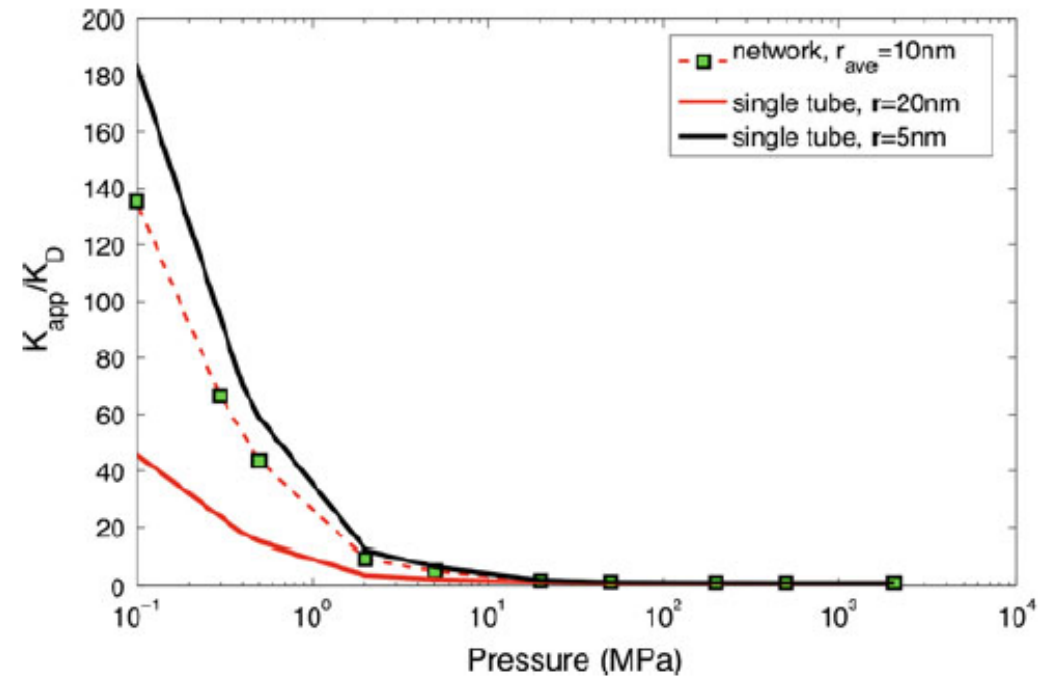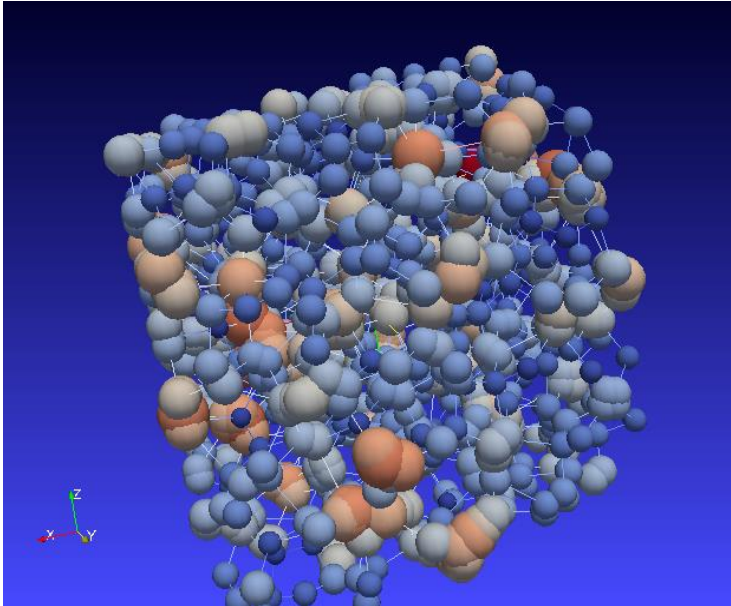
Validation with experimental data
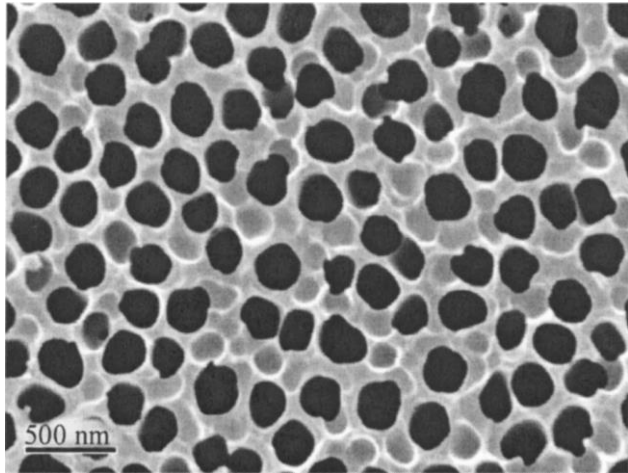
Artificial nanopores

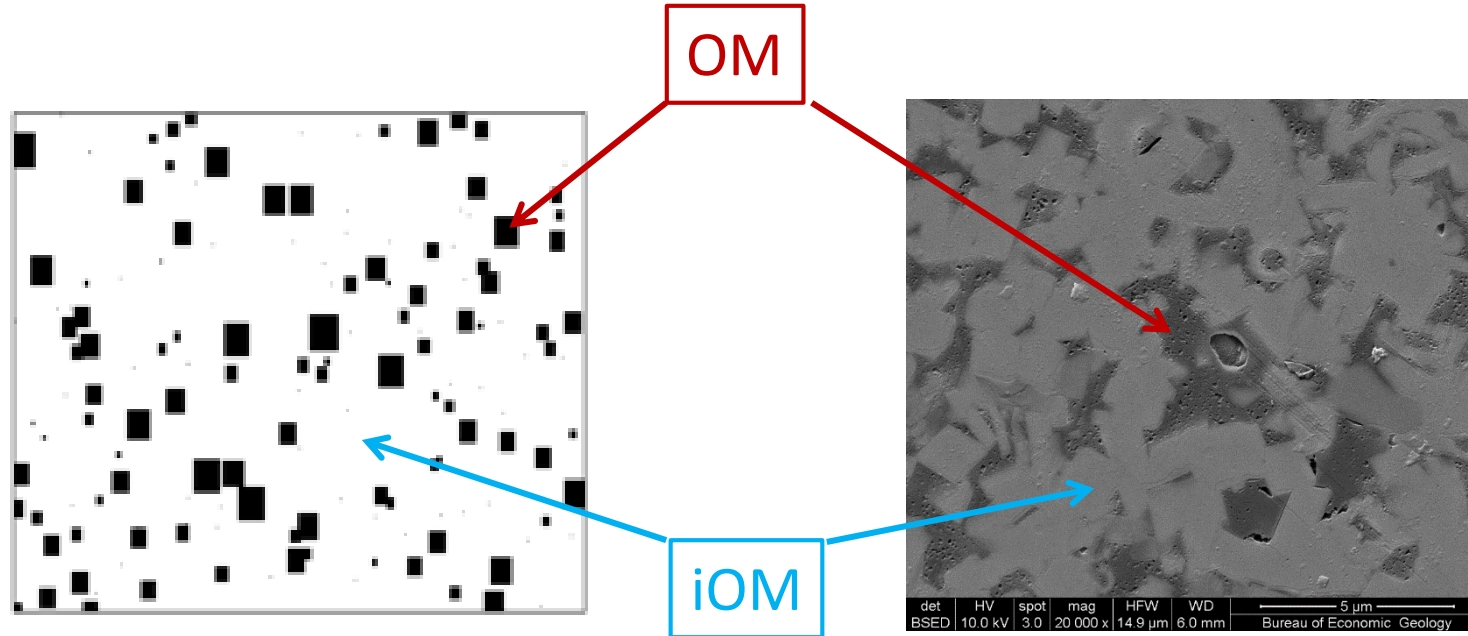*NASA Ames Research Center*

Pore network model

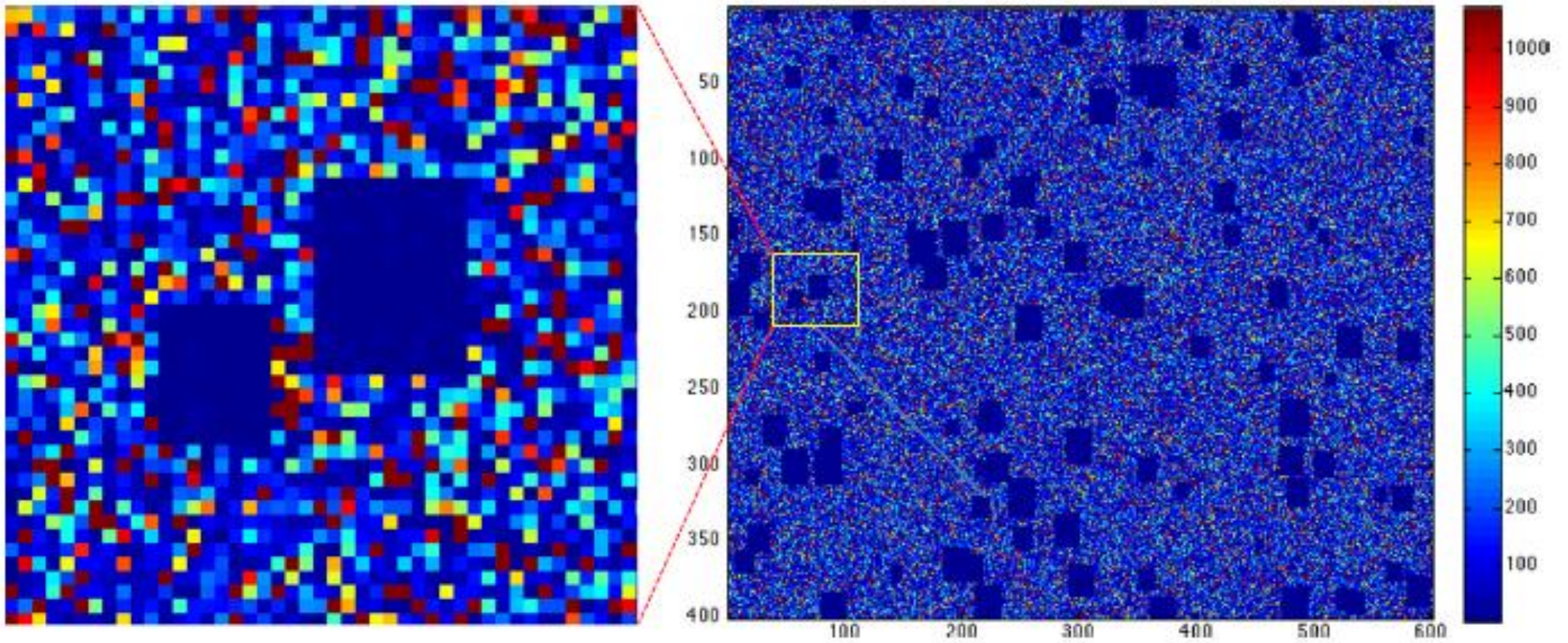*Mehmani et al., Transport in Porous Media (2013)*

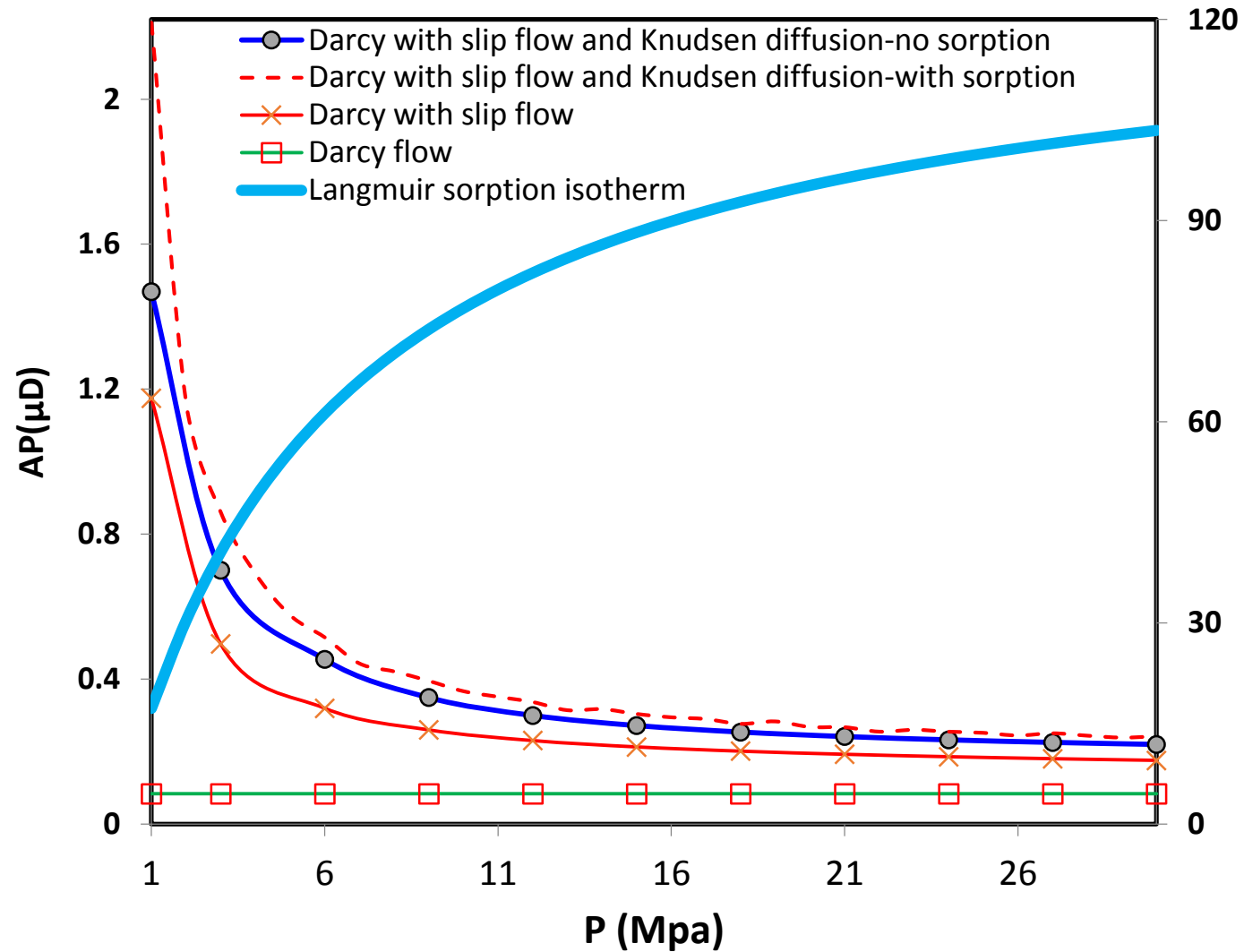# Stochastic permeability model

SEM to permeability

- TOC

- OM patch SD from SEM images

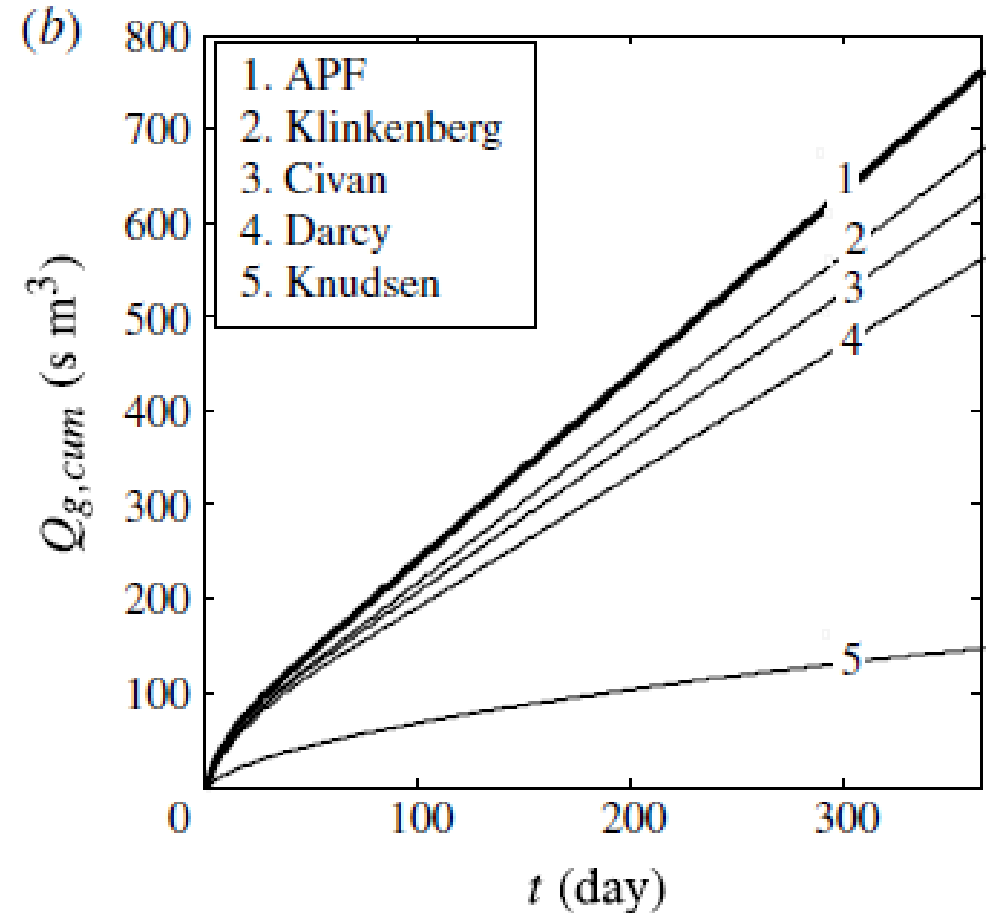- Pore SD in OM & iOM from N_2 & MICP

Stochastic model
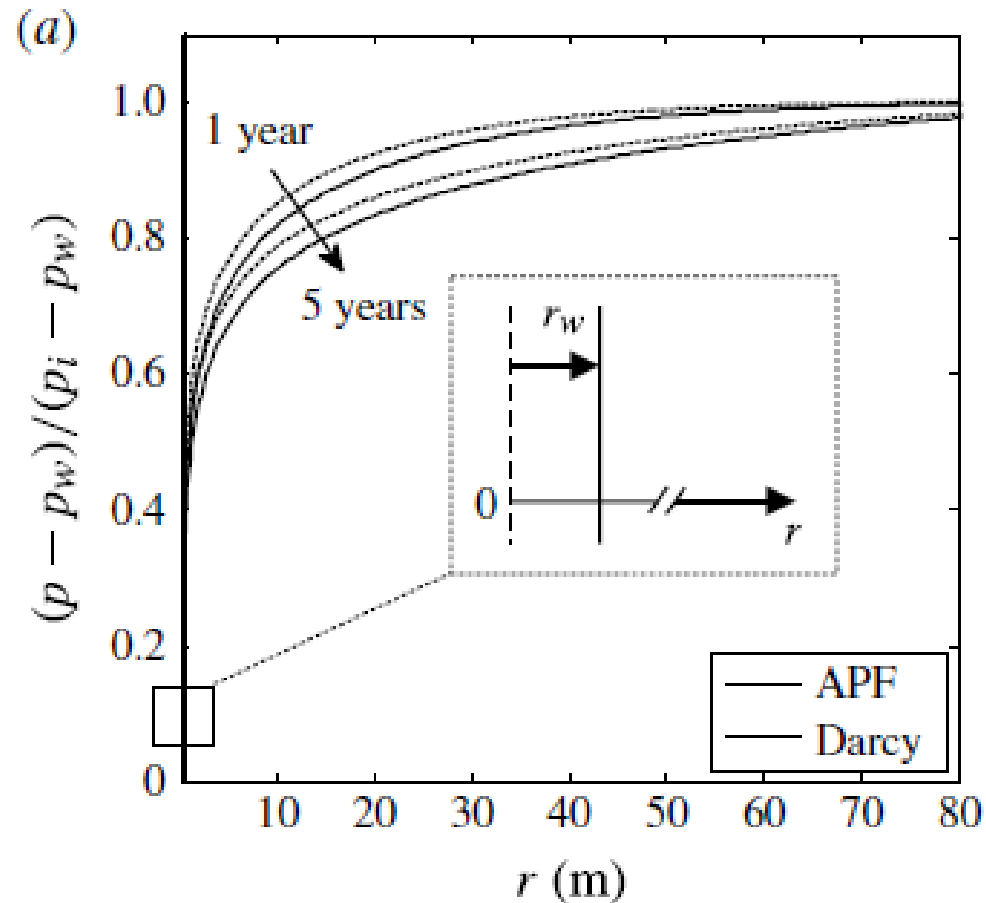

Naraghi & Javadpour, International Journal of Coal Geology (2015)

Effect of sorption

Reservoir model

Darabi et al., Journal of Fluid Mechanics, 2012

Model	Description	Pros	Cons
Javadpour (2009)	Model developed using slip flow assumption, represented by Maxwell theory. Accounts for Knudsen diffusion.	Simple.	Limited to straight tubes. Ideal gas. Ignores desorption.
Civan (2010)	Model developed using slip flow assumption, represented by simplified second-order slip model. Contains several empirical parameters	Higher-order slip flow.	Several empirical parameters.
Darabi et al. (2012)	Model developed using slip flow assumption, represented by Maxwell theory. Accounts for surface roughness and Knudsen diffusion in a porous medium.	Includes tortuosity and pore surface roughness.	Needs TMAC values. Ideal gas. Ignores desorption.
Akkutlu & Fathi (2012)	Model includes dual-porosity continua of matrix/fracture system, where matrix is composed of both organic and inorganic pores. Accounts for surface diffusion and sorption.	Dual-porosity system.	Complex numerical model.
Shabro et al. (2012)	A finite-difference based numerical model and geometrical parameters are used to reconstruct porous structure of shale, which is then used for pore-scale characterization. Permeability equation is borrowed from Javadpour (2009).	Spatial characterization and geometry of porous media included.	Complex numerical model. Ideal gas. Ignores desorption. Needs TMAC values.
Sakhaee-Pour & Bryant (2012)	Model developed using slip flow assumption, represented by Maxwell theory. Accounts for Knudsen diffusion.	Spatial characterization and geometry of porous media included.	Needs TMAC values. Ideal gas.
Mehmani et al. (2013)	Model developed by employing flow equation from Javadpour (2009) in pore network interconnected on nano and micro length scales.	Spatial characterization and geometry of porous media included.	Complex numerical model. Ideal gas. Ignores desorption. Needs TMAC values.
Singh et al. (2014)	Model developed using Navier-Stokes equation and kinetic theory (no slip flow assumption). Accounts for Knudsen diffusion, porous medium and sorption.	Simple. No empirical coefficient.	Ignores slip flow.
Rezaveisi et al. (2014)	Numerical model developed to study components of produced gas with time from nanometer sized pores. Relevant physics includes advection, slip flow and Knudsen diffusion.	Distinguishes different gas types.	Needs TMAC values.
Kelly et al. (2015)	Porous structure of shale is reconstructed using FIB-SEM image stacks and numerical study using LBM is performed to study petrophysical properties of shale. Permeability estimation is done using pressure driven flow.	Spatial characterization and geometry of porous media included.	Complex numerical model. Ignores slip, diffusion and desorption.
Chen et al. (2015)	Porous structure of shale is reconstructed using Markov Chain Monte Carlo (MCMC) on SEM images and its pore-scale characterization is performed. Apparent permeability includes flow from advection, Knudsen diffusion and slip. LBM is used to simulate fluid flow.	Spatial characterization and geometry of porous media included.	Complex numerical model. Ignores desorption. Several empirical parameters.
Naraghi & Javadpour (2015)	Model developed by stochastically characterizing organic and inorganic pores. Accounts for slip flow, Knudsen diffusion, surface roughness and desorption.	Distinguishes different pore systems in organic and inorganic matter. Real gases.	Needs additional information from SEM images. Needs TMAC values.
Singh & Javadpour (2015)	Model developed using the Langmuir slip condition and it does not carry several shortcomings associated with the use of Maxwell slip. Reliably predict apparent permeability in shale.	Simple and analytic. Gets slip coefficient from sorption data. Real gas.	Ignores local heterogeneity.

Model Name	Equation	Empirical Parameters	Description of Parameters
Knudsen	$\dfrac{2\phi r\mu M}{3x10^3 \tau RT\rho^2}\left(\dfrac{8RT}{\pi M}\right)^{0.5}$	None	None
Darcy	$\dfrac{\phi r^2}{8\tau}$	None	None
Klinkenberg	$\dfrac{\phi r^2}{8\tau}\left(1+\dfrac{b}{p}\right)$	b	Accounts for gas slip
APF	$\dfrac{\phi\mu M(\delta')^{D_f-2}D_k}{\tau RT\rho}+\dfrac{\phi r^2}{8\tau}\left(1+\dfrac{b}{p}\right)$	δ', D_f, b	Account for normalized molecule to pore size, pore roughness and slip, respectively
NAP	$\dfrac{4\phi\mu r}{\tau\pi}\left(\dfrac{\pi rz}{32\mu}+\dfrac{1}{3pM}\sqrt{2\pi MRT}\right)$	None	None
LSP (Singh & Javadpour, 2015)	$-\dfrac{\phi h^2}{4\tau}\left(\dfrac{1}{\left(-\dfrac{dP}{dX}\right)_{X=1}\left(2+\dfrac{3}{\sqrt{\bar{\bar{\beta}}}}\right)}\right)\dfrac{dP}{dX}\left(\dfrac{2}{3}+\dfrac{1}{\sqrt{\bar{\bar{\beta}}}P}\right)$	$\bar{\beta}$	Dimensionless form of β which accounts for higher-order Langmuir slip

More reservoir models
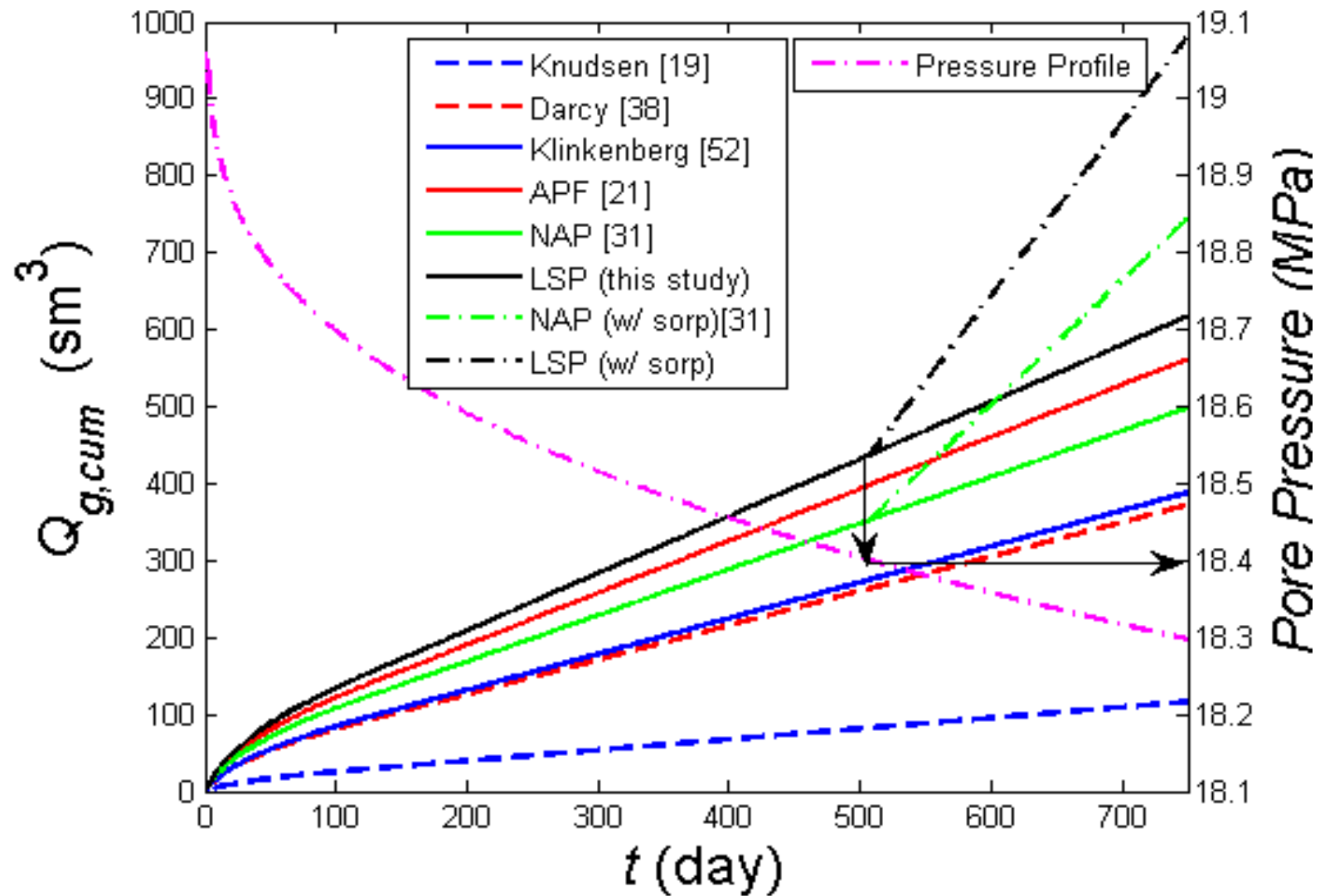
Lost gas estimation from canister tests

Gas content from canister tests

- Is the volume of gas released from a reservoir shale sample

- It is used to calculate gas-in-place volume for a reservoir

- Total gas content of a shale sample consists of three components:

lost gas (Q1)

measured gas (Q2)
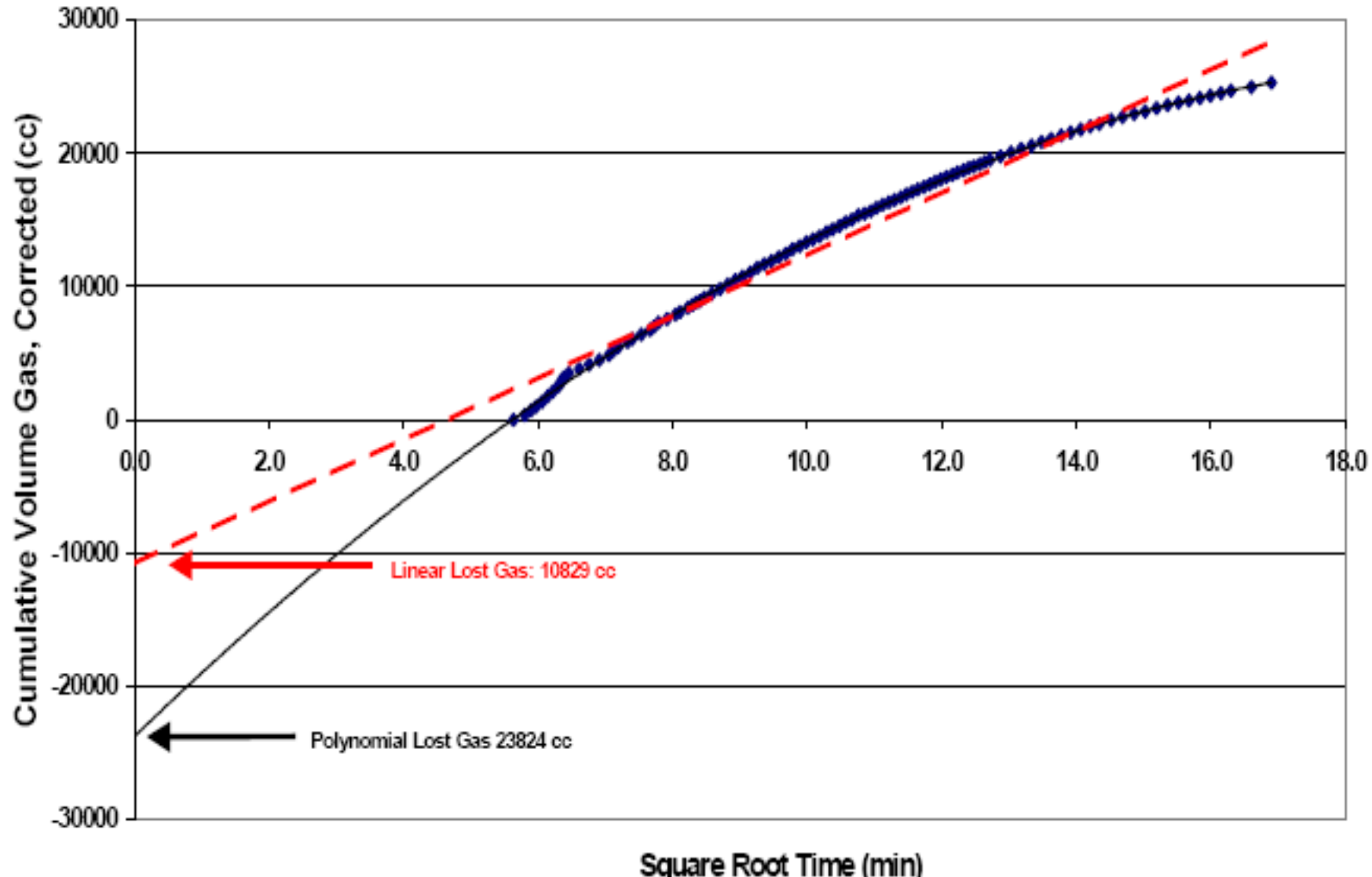
residual gas (Q3)

Core retrieval
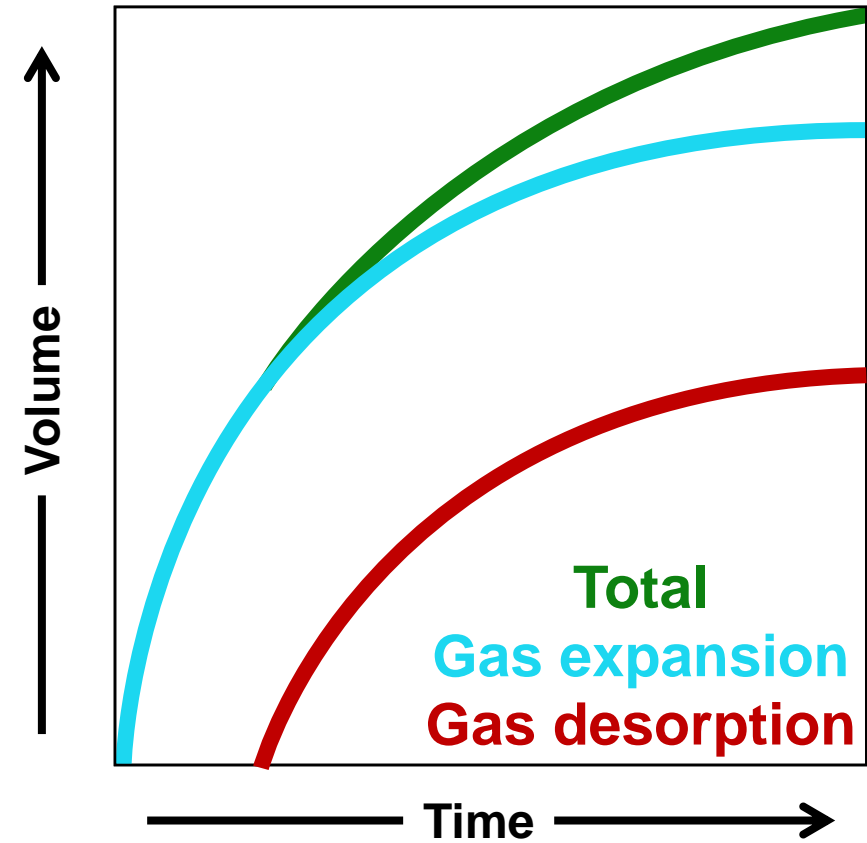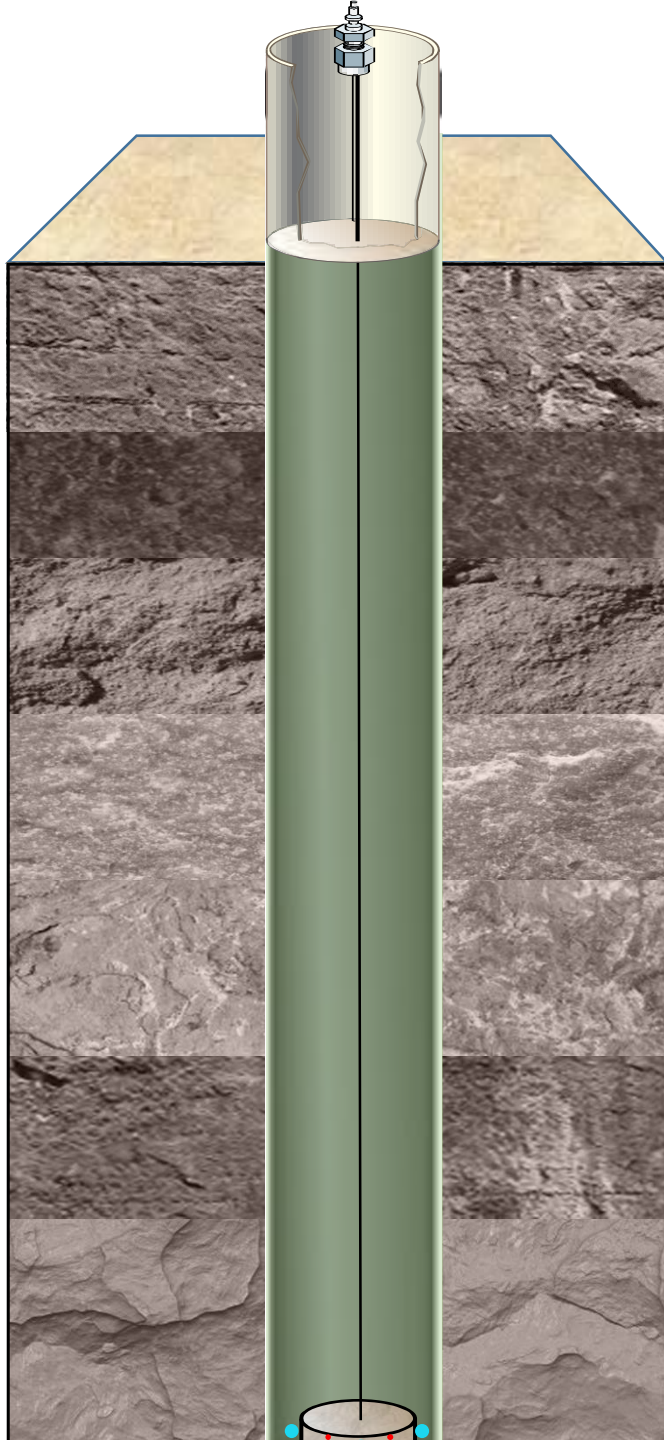
Canister Gas

- Reservoir temperature

- Lost gas + measured gas + crushed gas

- Adsorbed gas in CBM

- Free + adsorbed gas in shale

Waechter et al. World Oil, 2004

Lost gas estimation
Linear fit vs polynomial

Hosseini et al., SPE Journal, 2015
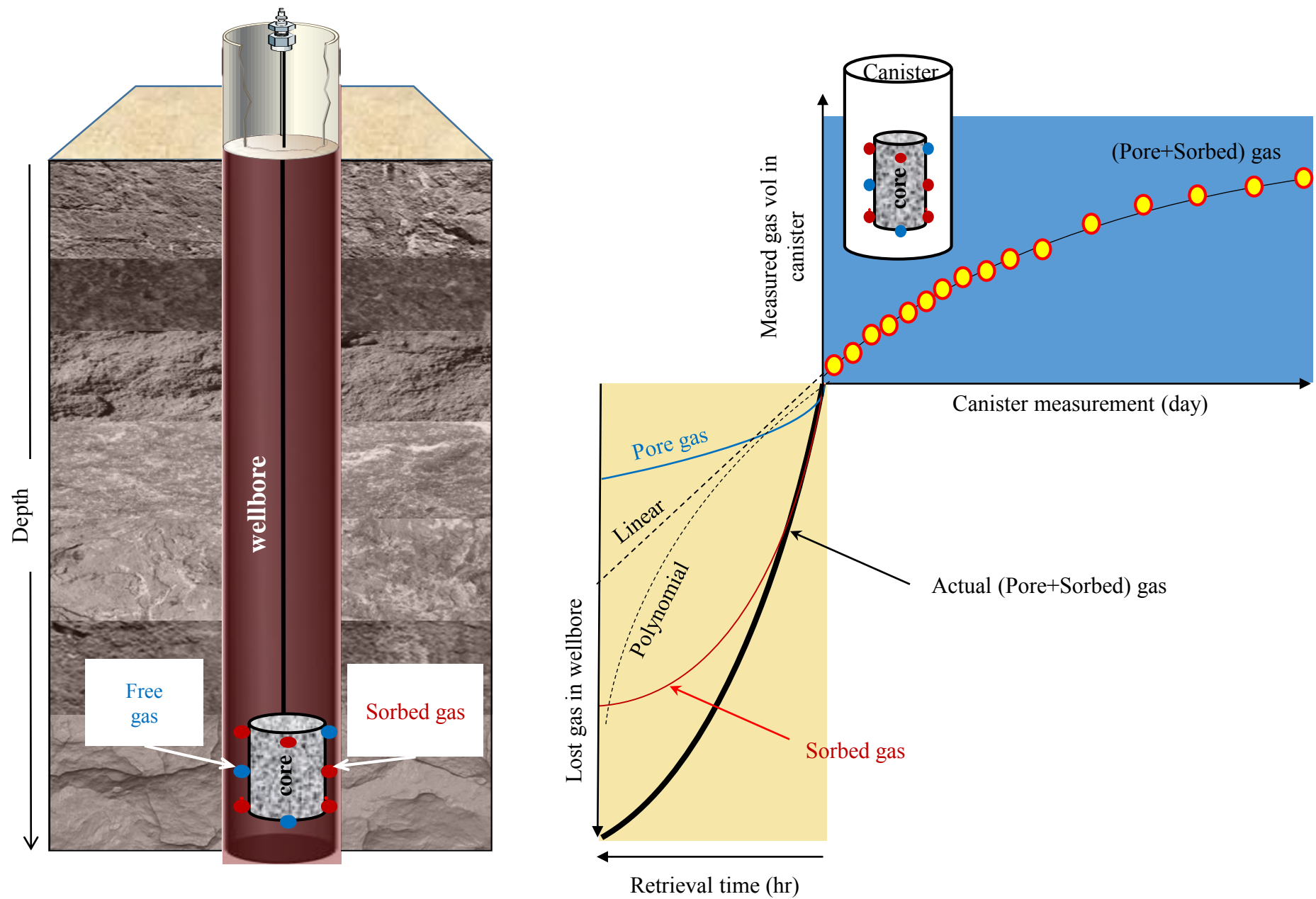
PDE, BC and IC

- $\phi c \dfrac{\partial P}{\partial t} = \dfrac{1}{r}\dfrac{\partial(rv_r)}{\partial r} + \dfrac{\partial(v_z)}{\partial z} + R$

- B.C. and I.C.
  - ➢ $P(r = R, z, t > 0) = f(t)$
  - ➢ $P(r, z = L, t > 0) = f(t)$
  - ➢ $P(r, z = 0, t > 0) = f(t)$
  - ➢ $P(r, z, 0) = P_i$
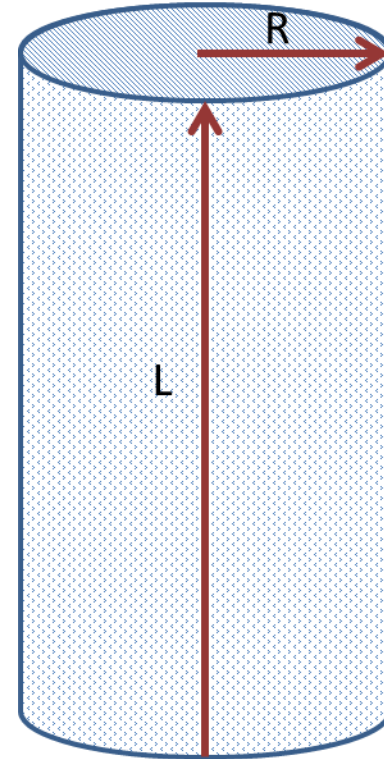
Solution in real domain

- After few steps:

  - $P_D(r_D, z_D, t_D) =$
    $e^{-\beta t_D} +$
    $2\sum_{m=1}^{inf} \left\{ \left[2\sum_{n=1}^{inf} \left\{ \left[e^{\frac{-t_D(\omega_m^2 v^2 + \lambda_n^2)}{(\alpha+1)}} - e^{-\beta t_D} \right] \frac{\beta(\alpha+1)(1-\cos(\omega_m))F(\lambda_n)}{(\beta(\alpha+1)-\omega_m^2 v^2 - \lambda_n^2)\omega_m} \right\} \frac{J_0(\lambda_n r_D)}{|J_1(\lambda_n)|^2} \right] \sin(\omega_m z_D) \right.$

  - $\omega_m = m\pi \qquad m = 1,2,\ldots$

  - $\lambda_n = J_0(0,n) \qquad n = 1,2,3,\ldots$

- Average pressure:

  - $\overline{P_D}(t_D) = \frac{1}{V}\int_0^1 \int_0^1 P_D(r_D, z_D, t_D)\, dz_D\ dr_D$

  - $\overline{P_D}(t_D) = \frac{1}{\pi}\left[e^{-\beta t_D} + 4\sum_{m=1}^{inf}\sum_{n=1}^{inf}\left[e^{\frac{-t_D(\omega_m^2 v^2 + \lambda_n^2)}{(\alpha+1)}} - e^{-\beta t_D} \right] \frac{\beta(\alpha+1)(1-\cos(\omega_m))^2}{(\beta(\alpha+1)-\omega_m^2 v^2 - \lambda_n^2)\lambda_n^2 \omega_m^2} \right]$

Pressure profile
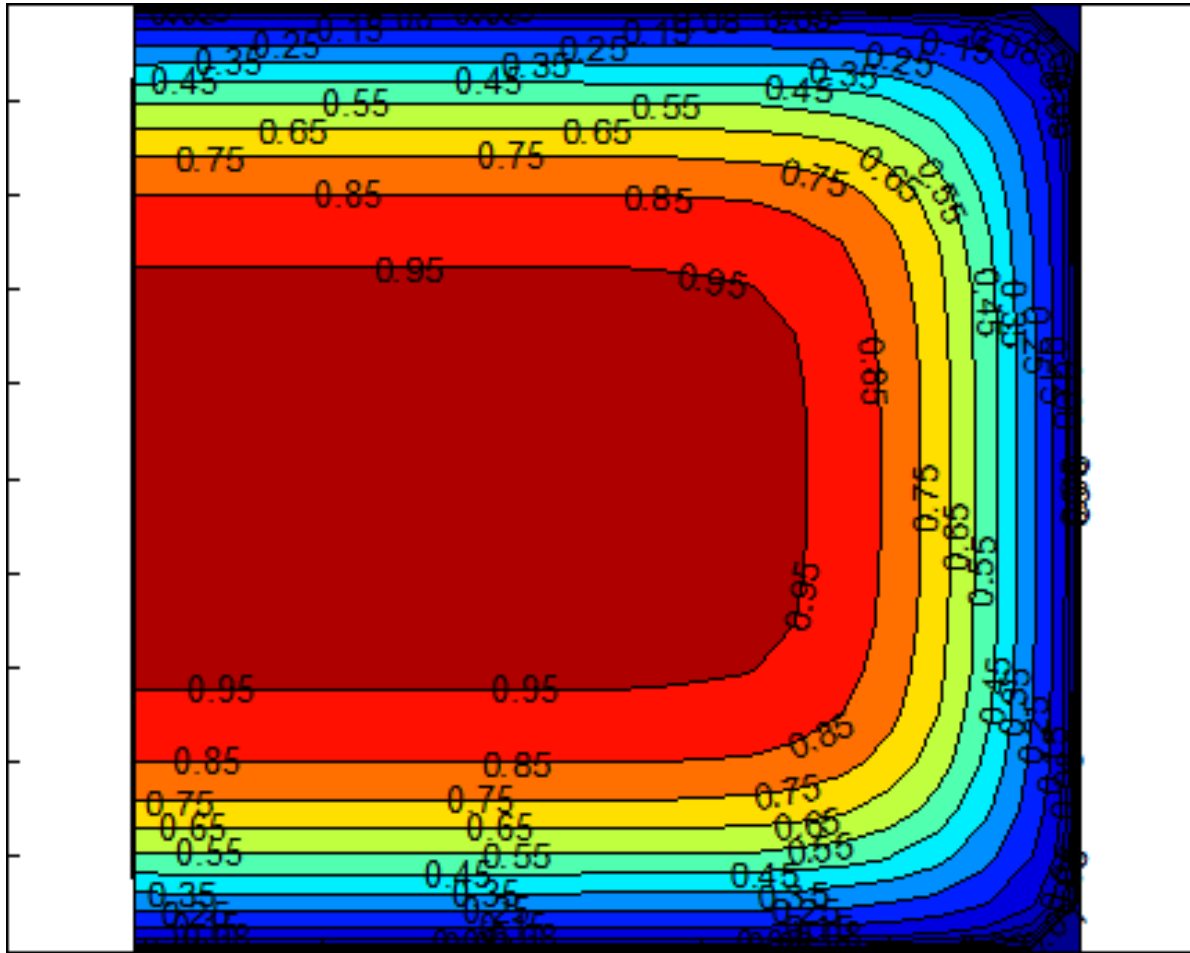
Rigorous estimation of lost gas

Canister data

Our match (Expansion + desorption)

Gas release in canister only from expansion
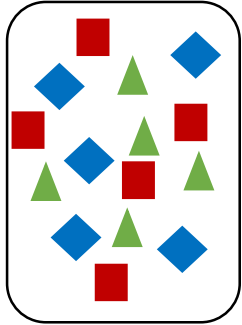
desorption

Expansion

Total
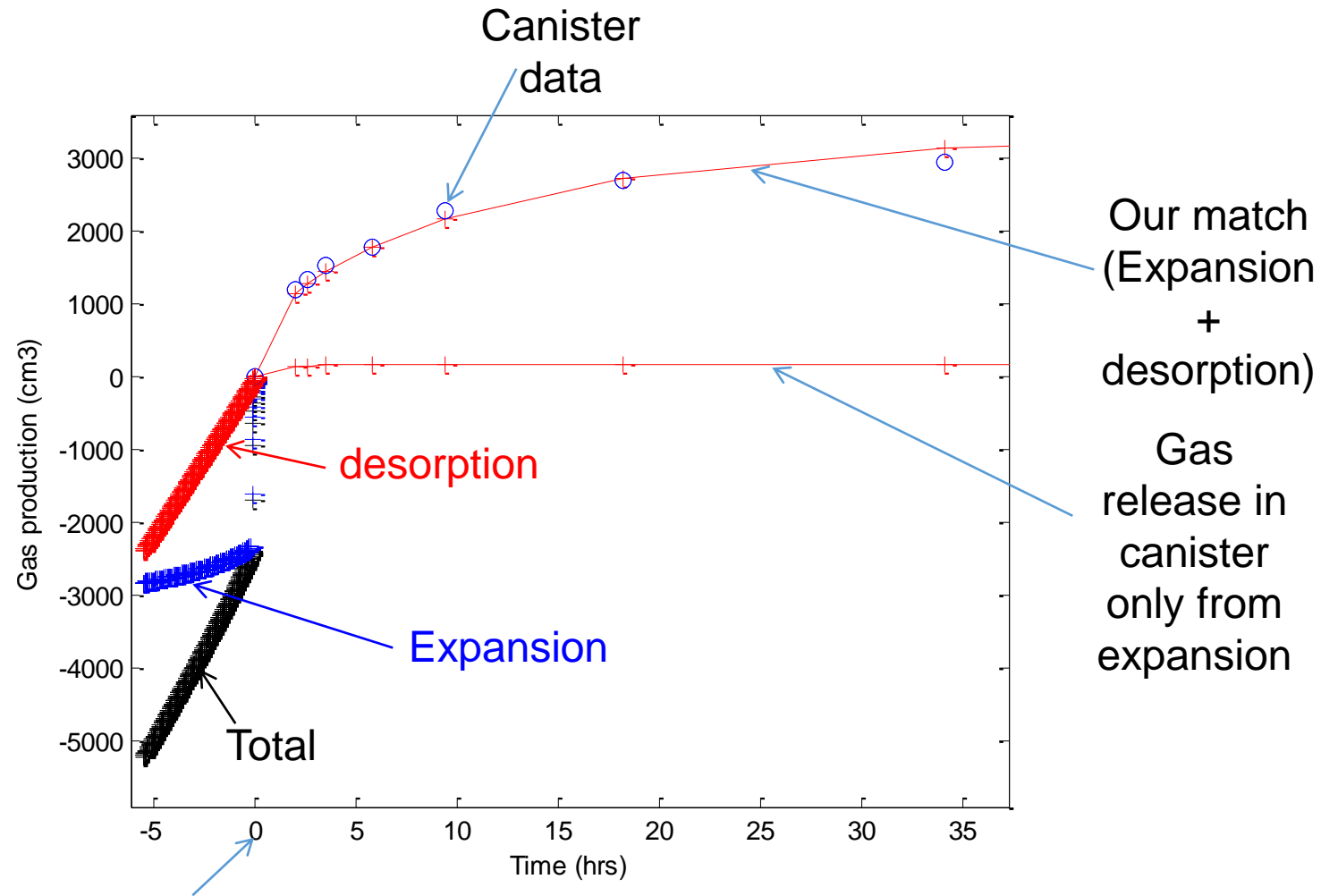
Time zero represents the time core is placed in canister

Hosseini et al., SPE Journal, 2015

In-situ gas chromatographic separation (CS) in shale reservoirs
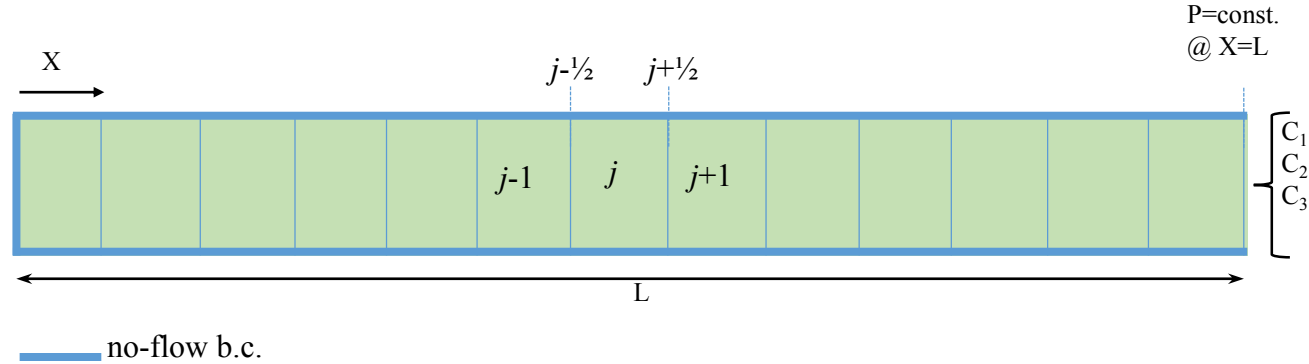
Chromatographic separation (CS)
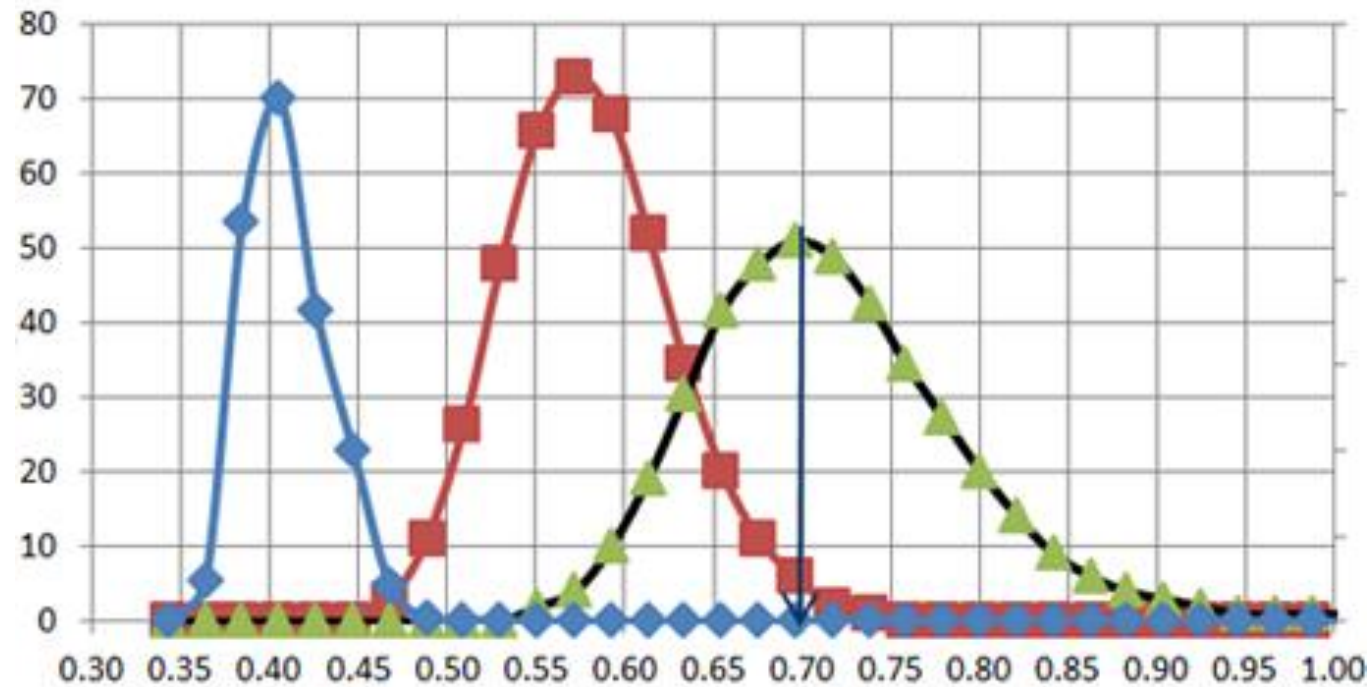
Field observation (Freeman, Moridis, Michael, Blasingame, 2012)

Temporal variation of gas composition in produced gas

Is the observed variation related to an in-situ separation process?

If yes, how we control the composition variation?

Governing equations

P=const.
@ X=L

$$\frac{\partial(\phi\rho y_i)}{\partial t} = -\frac{\partial}{\partial x}\left[-y_i\rho\frac{k_D}{\mu}\left(1+\frac{b_i}{P}\right)\frac{\partial P}{\partial x} - \frac{D_{k,eff,i}}{RT}\frac{\partial}{\partial x}\left(\frac{Py_i}{Z}\right)\right] + r_i$$

$$P_{(x,\,t\,=\,0)} = P_i$$

$$y_{i(x,\,t\,=\,0)} = y_{i0} \quad \text{for } i = 1, 2, .., N_c - 1$$

No flow bc at the inlet and Danckwertz bc at the outlet

$$\left[y_i\right]_{Outlet} = \left[y_i\right]_{N_{Block}} \quad for \quad i = 1,.., N_c - 1$$

Input data

Property	Value
Darcy permeability, K_d (nD)	100
Porosity, ϕ	0.1
L(m)	4
Initial pressure (psi)	5000
Outlet pressure (psi)	1000
Temperature (K)	373
Tortuosity	4
Number of grid blocks (number of refined grid blocks near the outlet)	150 (70)

Spatial P & C profiles (12 days)
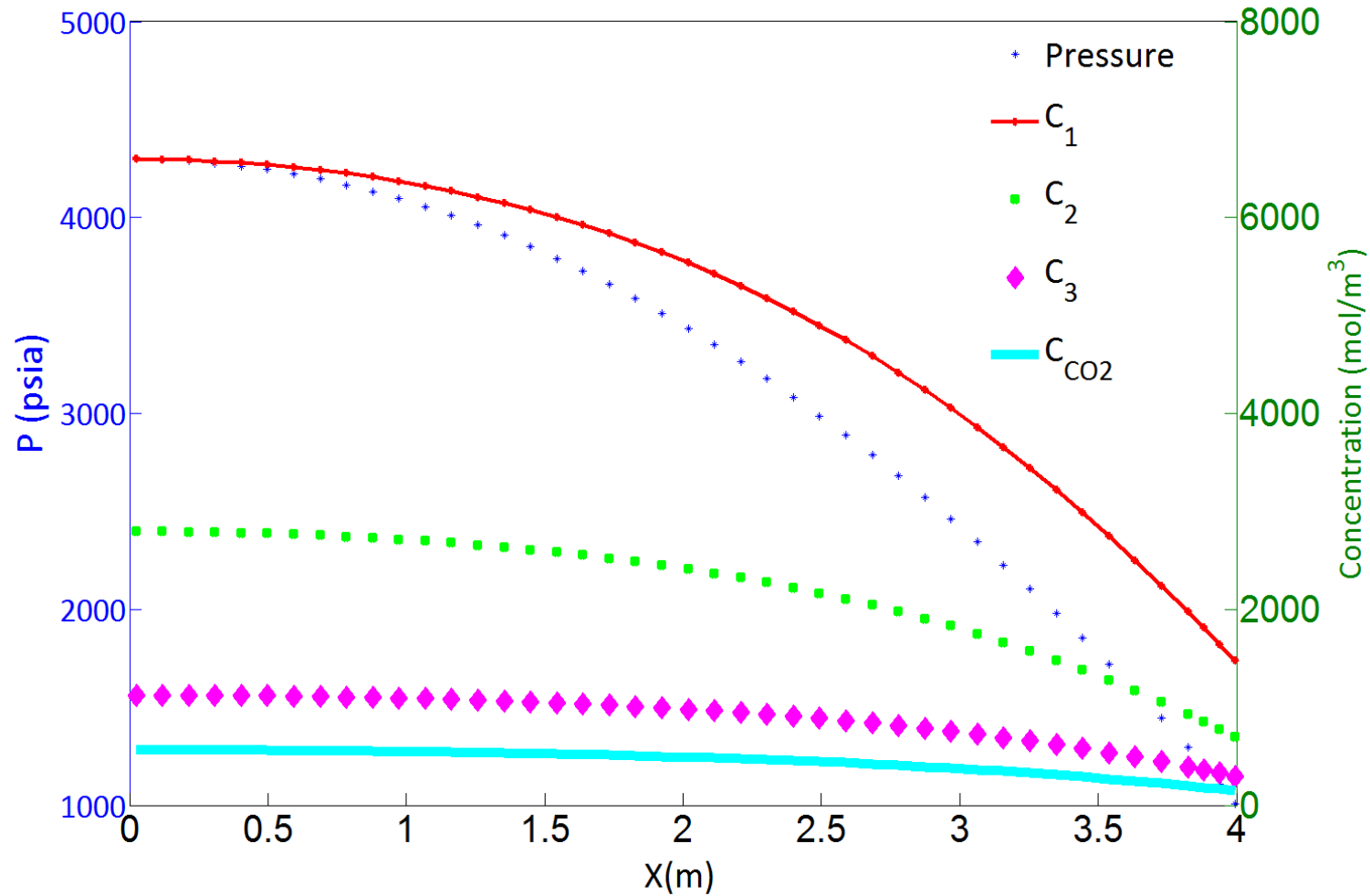
Temporal variation of P and normalized C_n
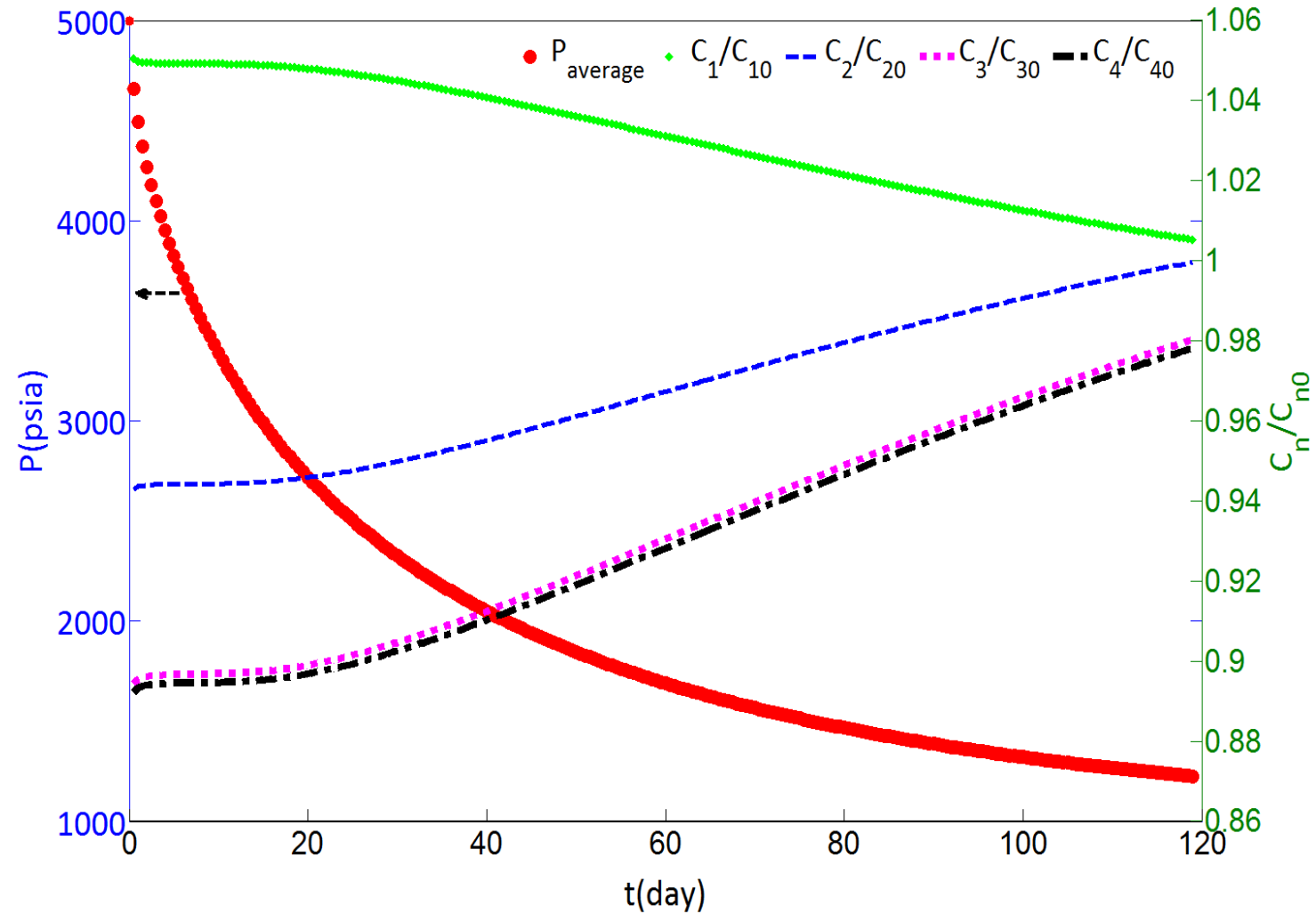
Effect of initial P
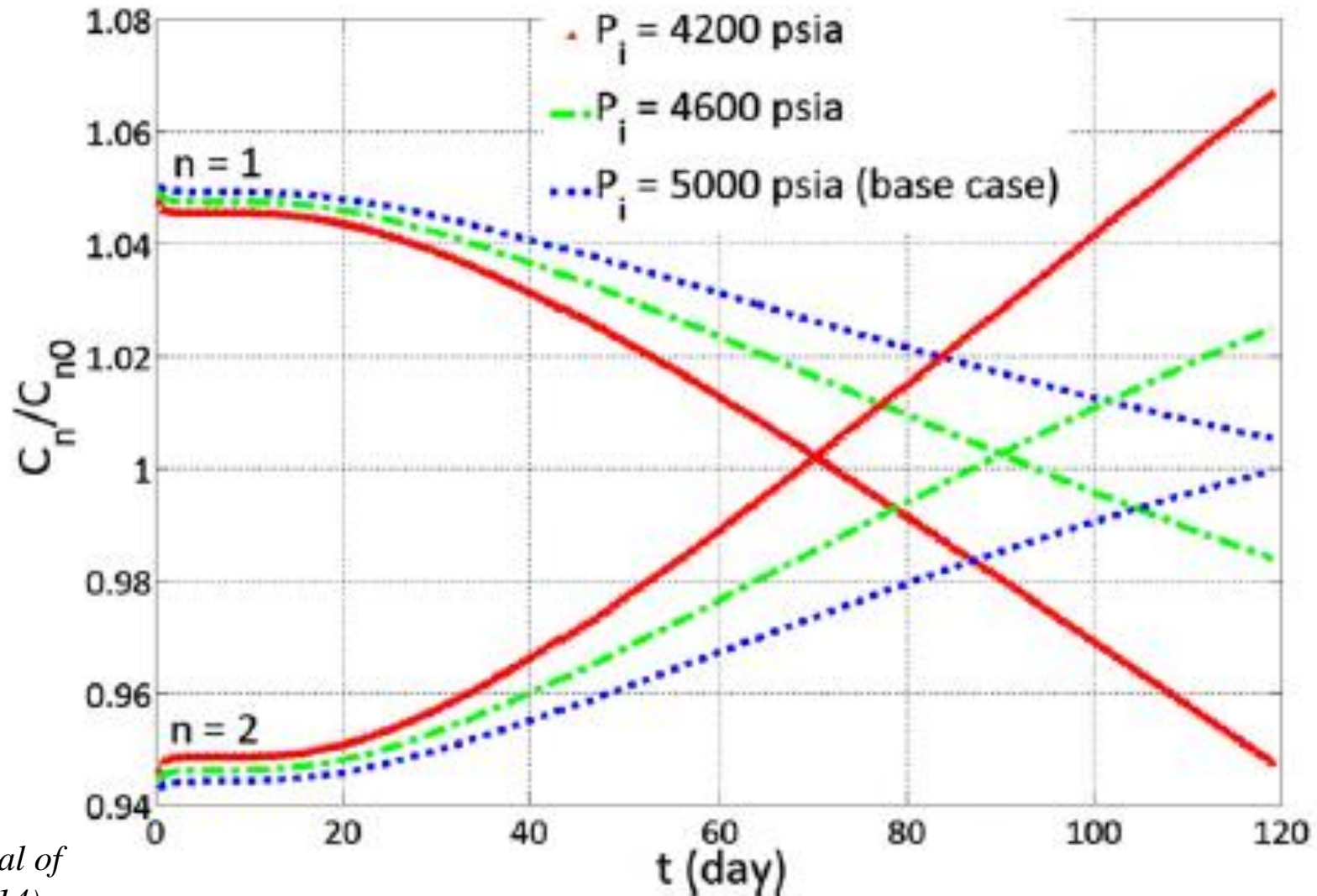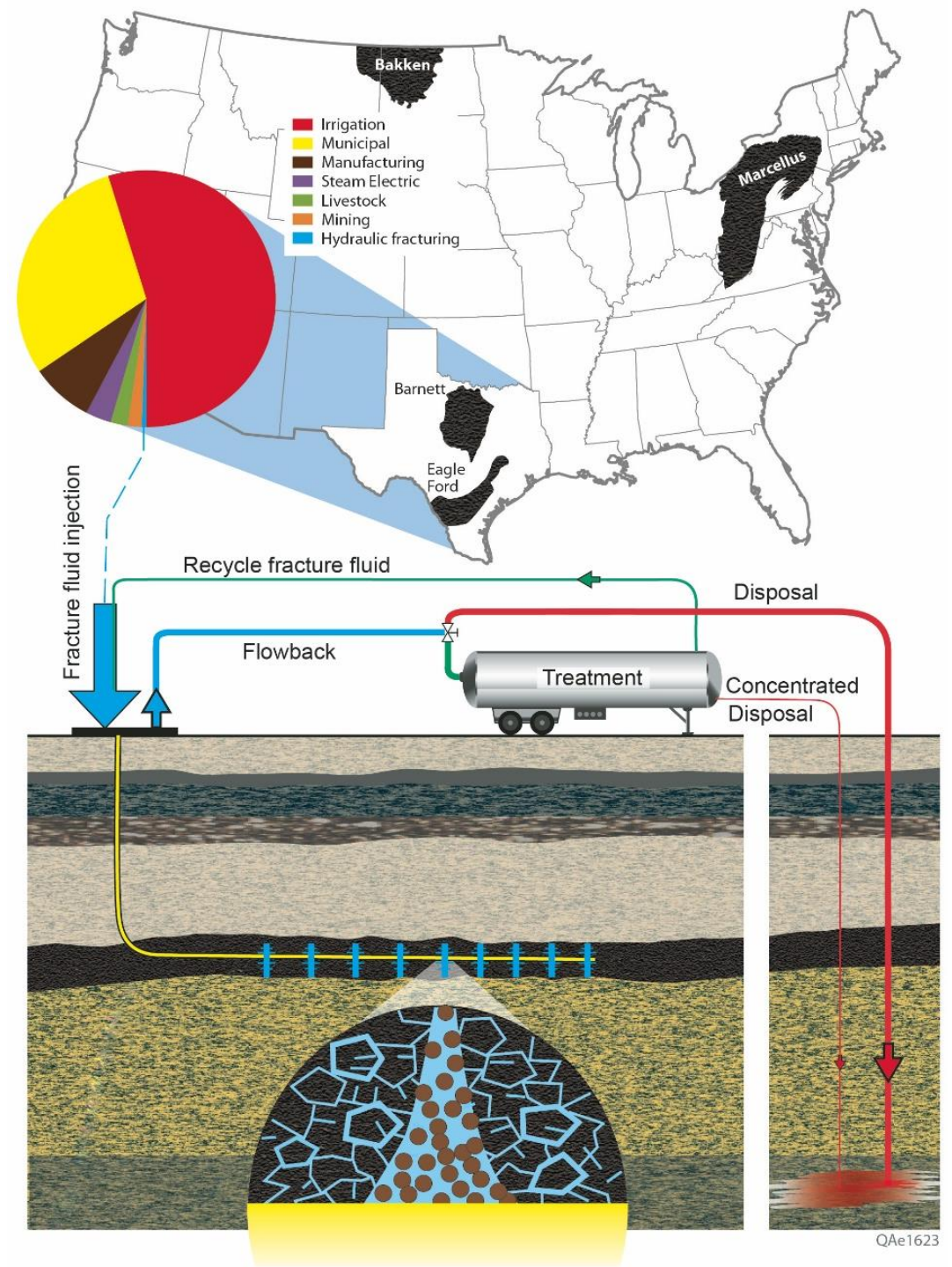

Rezaveisi et al., International Journal of Coal Geology (2014)

Effect of matrix size
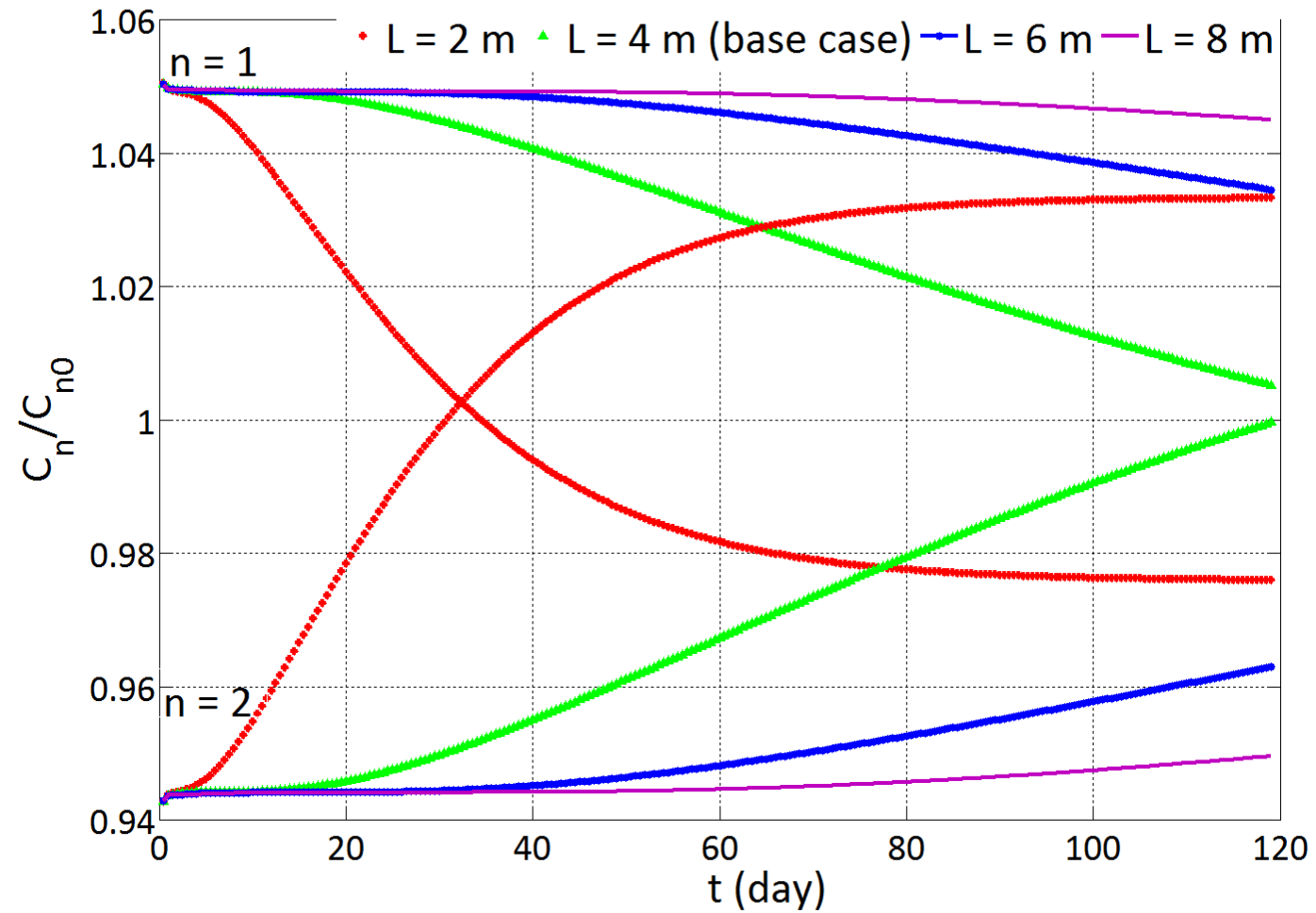
In a 2D model can be used to determine fracture spacing

Liquid flow in shale and fracture fluid loss

Hydraulic fracturing

After fracking, a portion of injected water

➢ flows back

➢ remains in fractures & gradually flows back

➢ leaks off into matrix

Hydraulic Fracture Treatments Pumping Phase

Secondary natural fractures E-W

Hydraulic fracture resumes in S_{Hmax} direction at natural fracture tip

Flowback

Dominant natural fracture clusters NW-SE

Reactivation of natural fractures

Horizontal wellbore with perforation

Hydraulic fractures

Forced Imbibed water

~ 250 ft

N

S_{Hmax}

Modified after Gale et al. (2007)
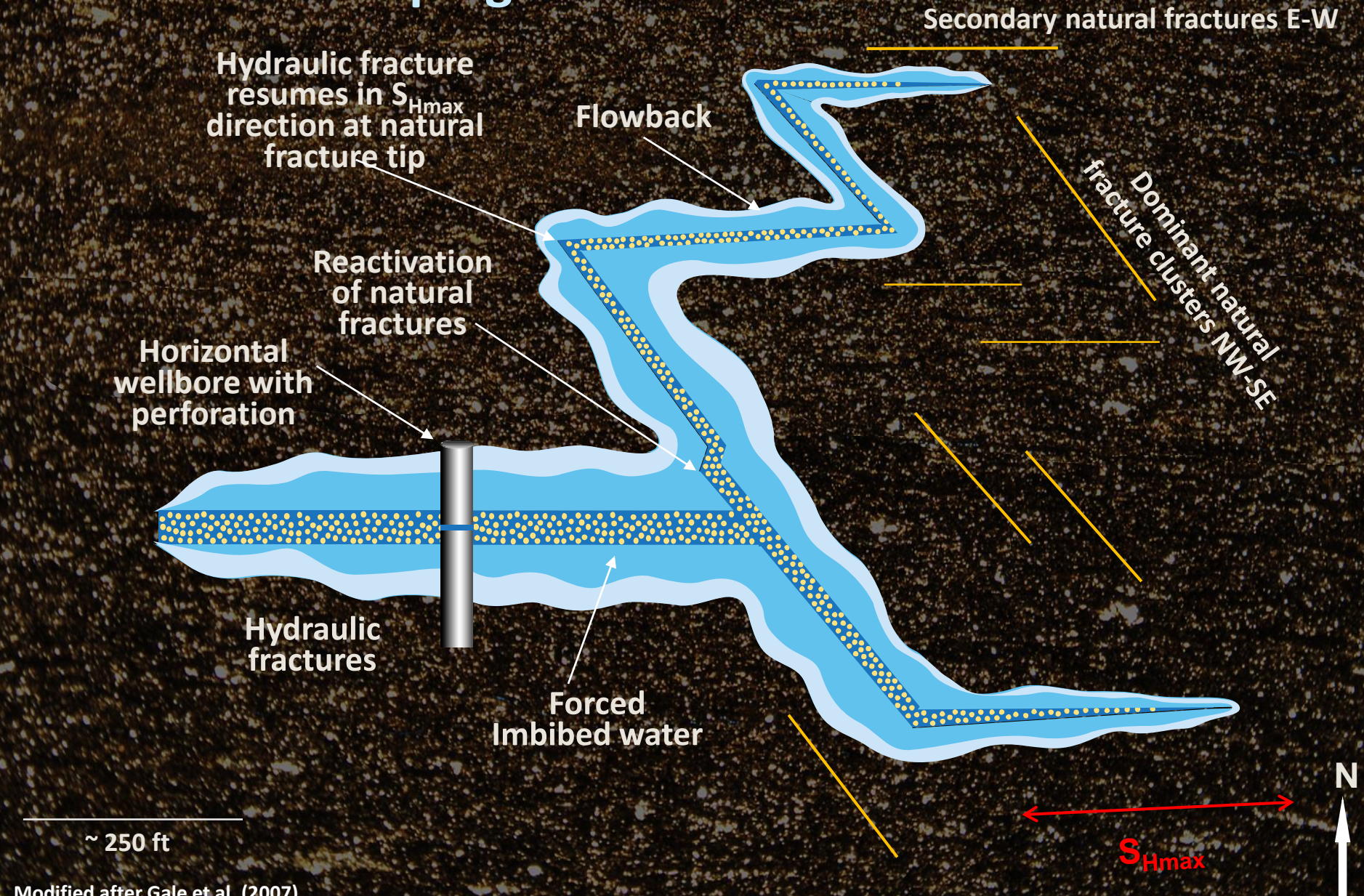
Liquid slip in a pore
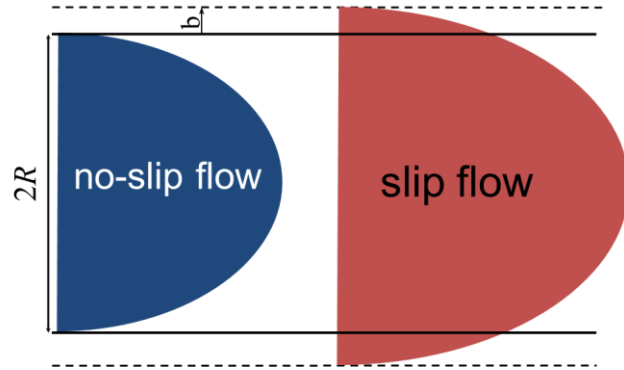
R= 10 μm
U_{slip} = 1.02 U

Negligible in conventional reservoirs
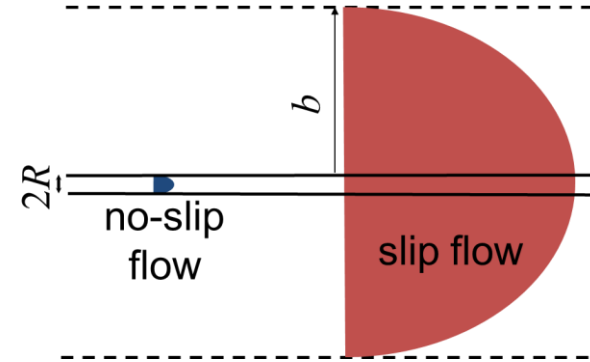
R= 10 nm
U_{slip} = 10^2 U

Slip must be included in shale

How to measure slip length?

- Slip depends on the surface and fluid type

- Slip length for a liquid flowing inside a tube or outside an object is the same

- It is easier to measure slip length for a fluid moving over an object

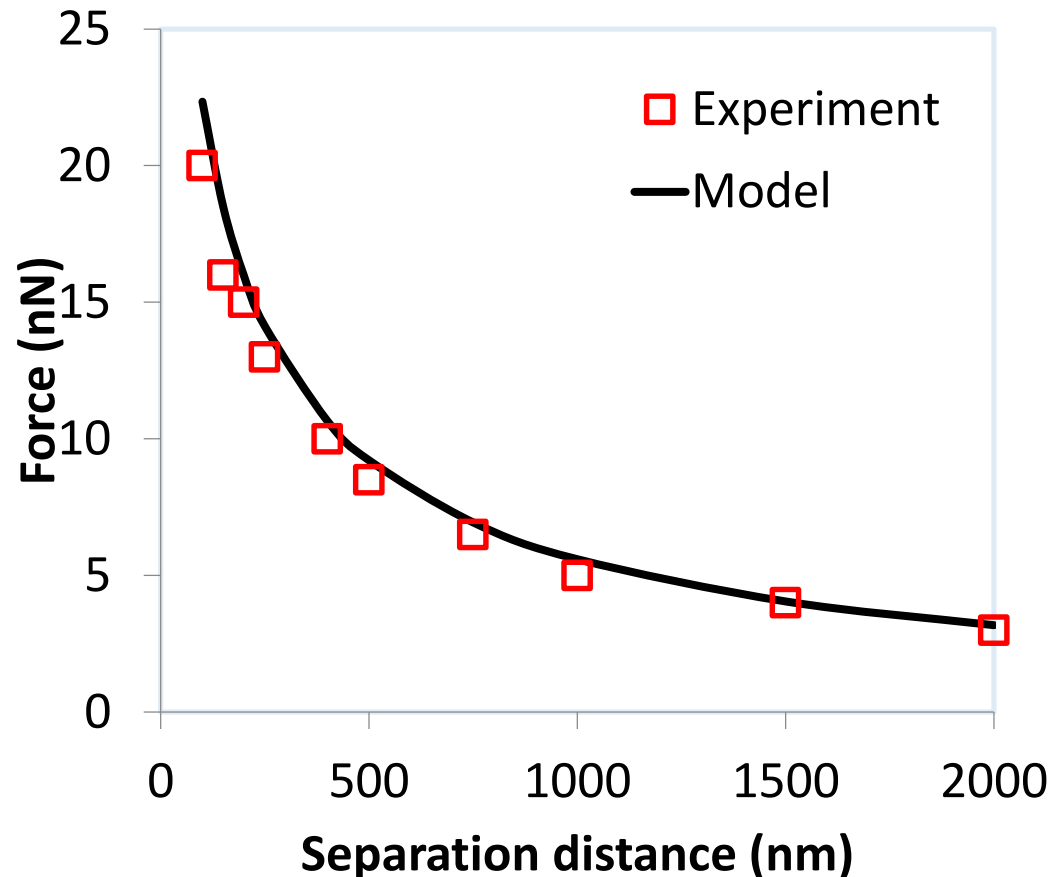- We measure slip length over a spherical object and then relate it to liquid flow in pore

How to measure slip length?
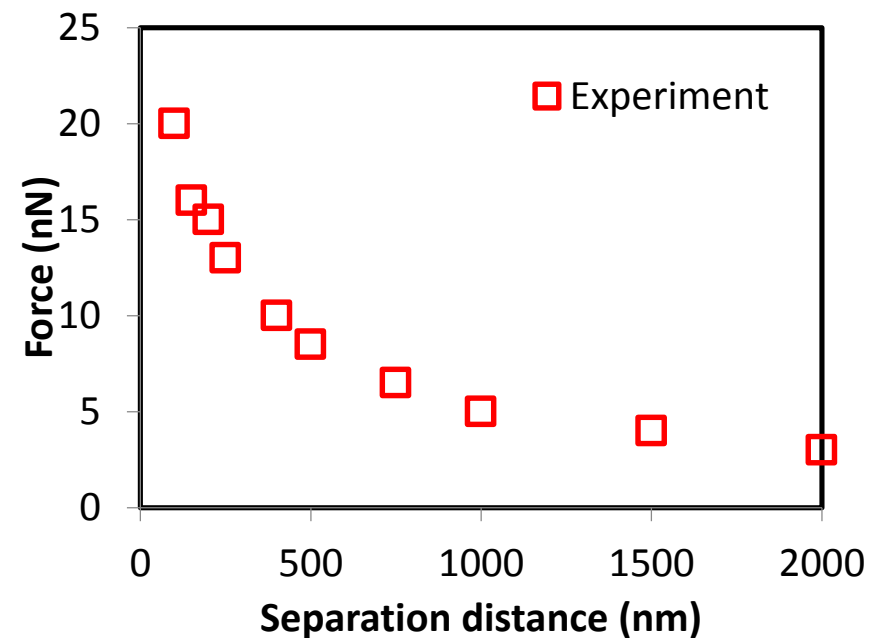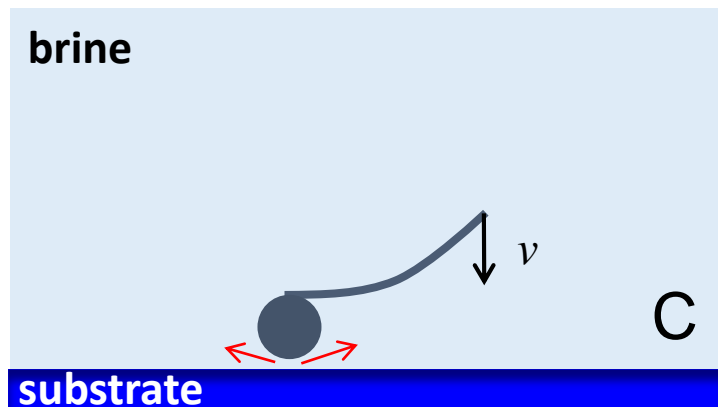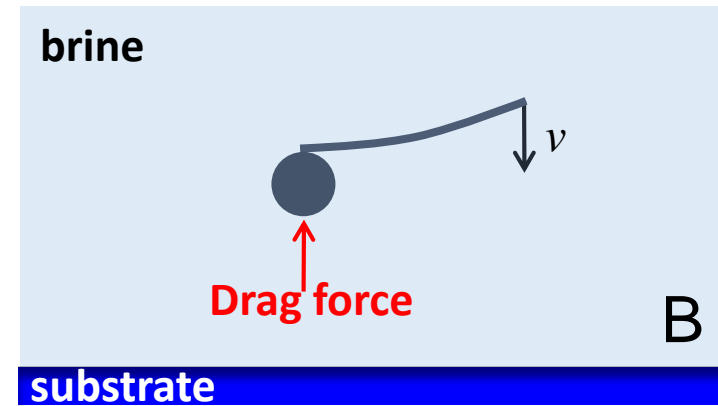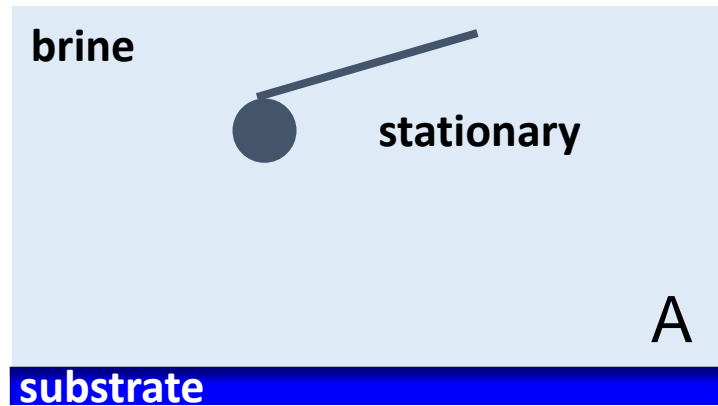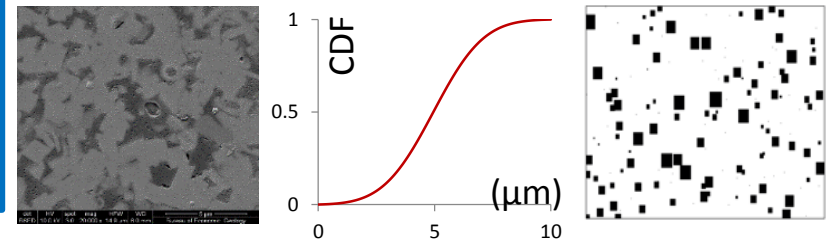
Atomic force Microscopy (AFM)
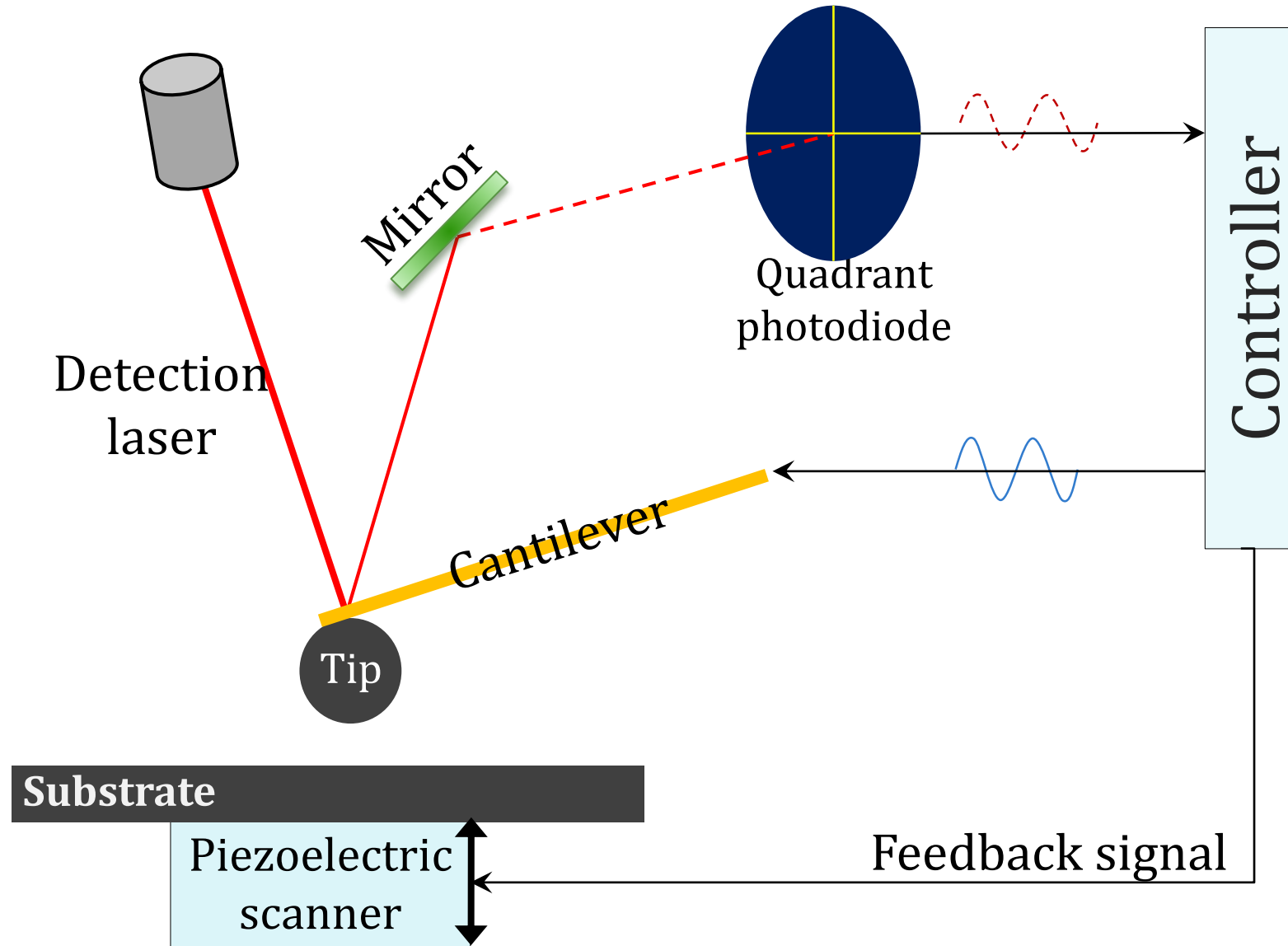
Slip length from AFM data

$$F = \frac{6\pi R^2 \mu \nu}{h} f*$$

| System of interest	Approach speed (μm/s)	
	20	15
CH-coated substrate and CH-coated sphere	**280 nm** n=182	**253 nm** n=190
Ion-milled shale and CH-coated sphere	**189 nm** n=369	**176 nm** n=353

Javadpour et al., Fuel, 2015

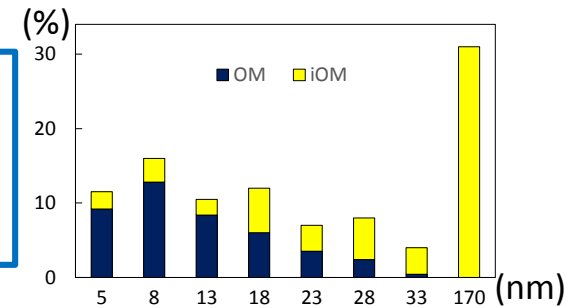# Apparent liquid permeability model

(a) Generate ensemble of OM & iOM realizations conditioned to OM Patch SD
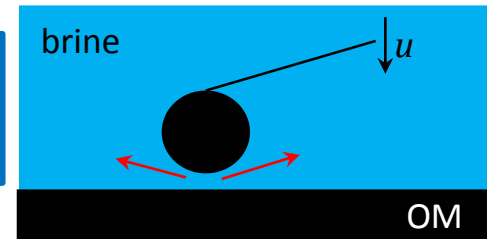
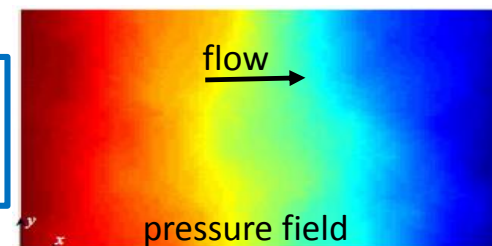**(b)** Discretize space domain to gridblocks smaller than the smallest patch size
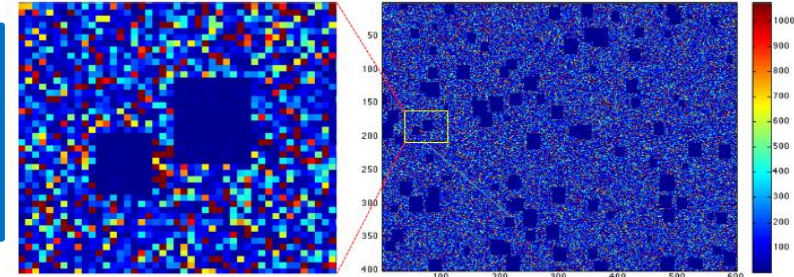
(c) Assign pore SD measured by N_2 sorption, MICP, or NMR within OM and iOM
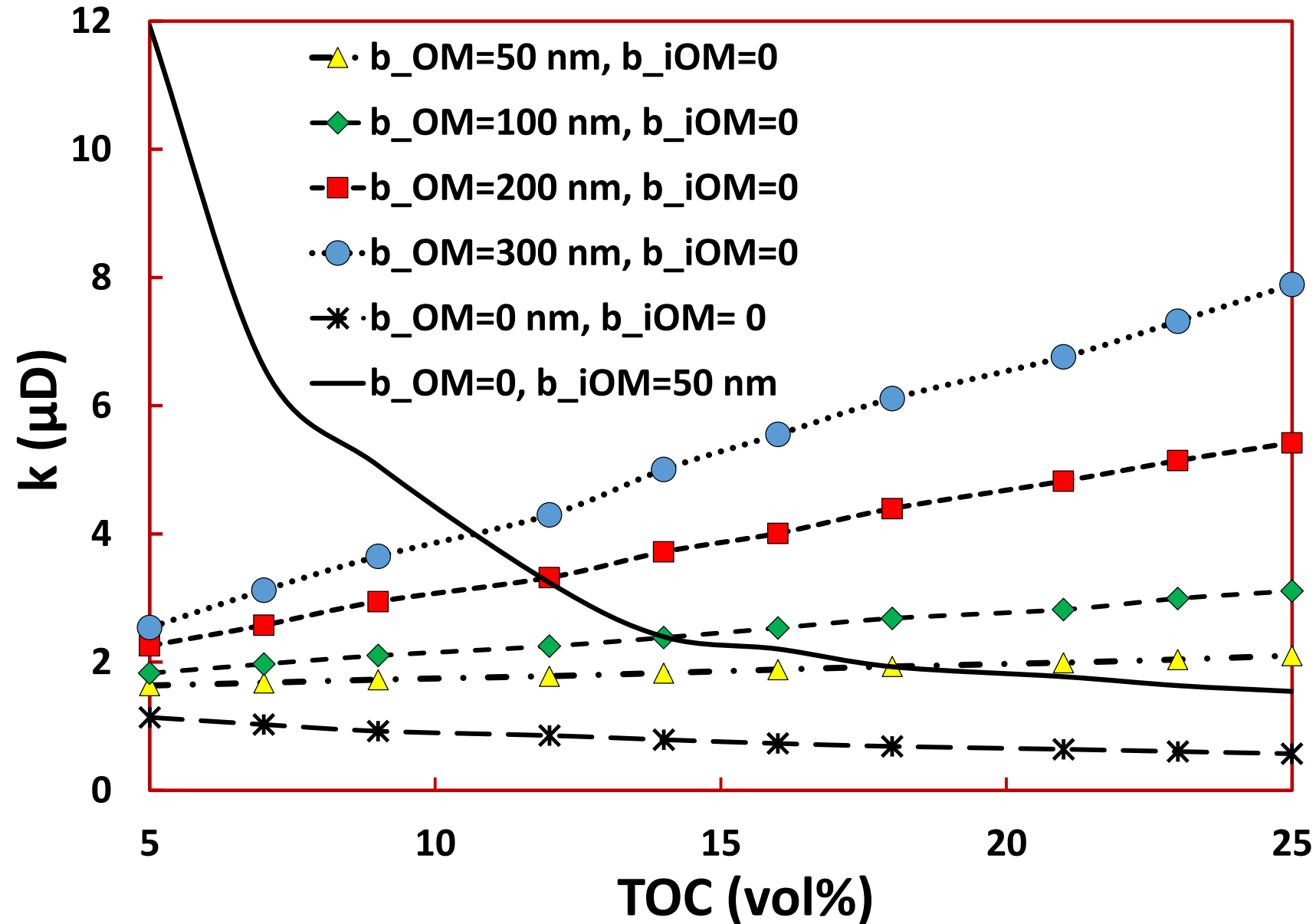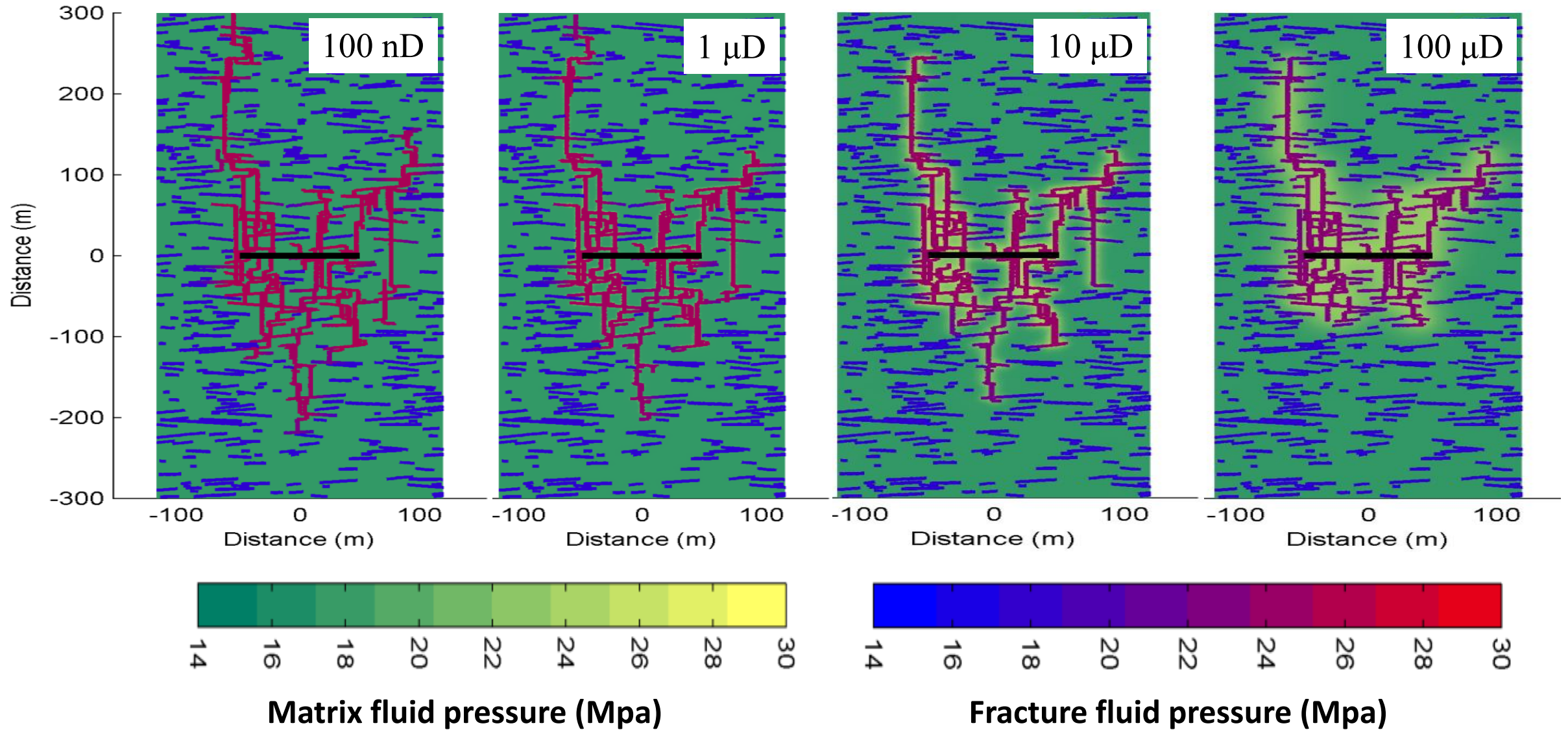
(d) Assign AFM measured slip length to pores in OM & iOM

(e) Solve pressure field to calculate ALP or use Eq. (4)
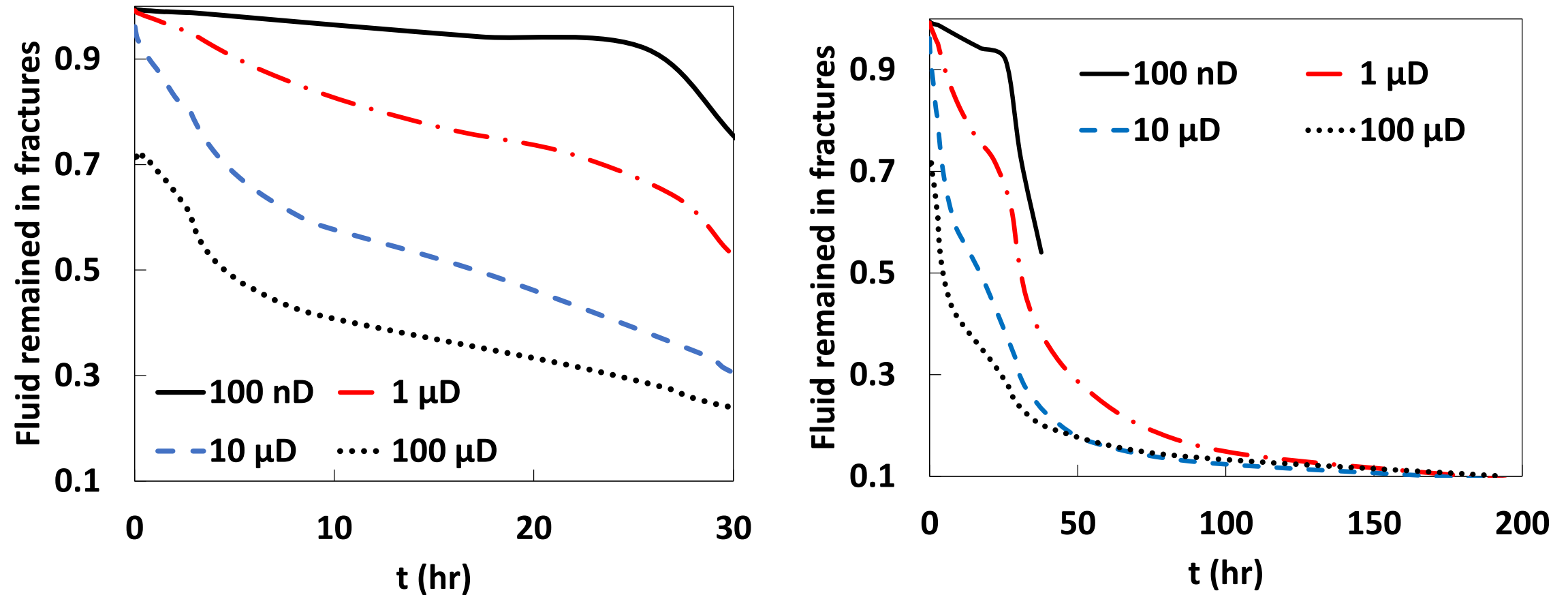
Impact of slip length & TOC on liquid permeability

Legend:
- b_OM=50 nm, b_iOM=0
- b_OM=100 nm, b_iOM=0
- b_OM=200 nm, b_iOM=0
- b_OM=300 nm, b_iOM=0
- b_OM=0 nm, b_iOM= 0
- b_OM=0, b_iOM=50 nm

y-axis: k (µD)
x-axis: TOC (vol%)

Effect of liquid slip on fracturing

Matrix fluid pressure (Mpa)

Fracture fluid pressure (Mpa)

Liquid leak-off into matrix during fracturing

Javadpour et al., Fuel, 2015

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Questions?