Shale Gas Opportunities and Challenges*

R. Marc Bustin[1], A. Bustin[1], D. Ross, G. Chalmers, V. Murthy, C. Laxmi, and X. Cui

[1]University of British Columbia

Synopsis

Shale gas is defined as a fine-grained reservoir in which gas is self-sourced, and some of the gas is stored in the sorbed state. Sorbed gas is predominantly stored in the organic fraction– so organics are present. Shale gas is not just 'shale'.

Productive gas shales range from organic-rich, fine-grained rocks, such as the Antrim or Ohio Shale, to variable facies rocks, such as Lewis Shale.

Pore size in fine-grained rocks is really small; pore size distribution is variable; porosity, which is variable (order of magnitude variation), reflects mineralogy and fabric.

Maturity and TOC effect
Thermal maturation structurally transforms organic fraction, creating more microporosity, hence potential adsorption sites
Slope of line showing absorbed gas capacity vs. TOC is proportional to maturity/kerogen type.

General Observations
- porosity decreases with diagenesis and effective stress

- quartz maybe positive (biogenic) or negatively (detrital) correlated with TOC
- more siliceous and silicified shales are more brittle than clay, organic or carbonate rich shales and have greater propensity to be fractured and to be fraced - (greater Young's modulus and lower Poisson's Ratio)
- BUT TOO SILICOUS = NO K or Porosity

CRITICAL TO DEFINE MECHANICAL STRATIGRAPHY

Background—learnings to date

thick sequences of shale with variable amounts of gas exist in many/most basins

shales are extremely heterogeneous in their properties but at a scale not generally considered

early views that organic geochemistry is "the" screen for prospectively is proving incorrect

evaluating gas in place and testing productivity by drilling and fracing is expensive- clear need for exploration/development model

main risk is reservoir access- and mechanical stratigraphy

Challenges

- screening exploration targets
- determining intervals to frac or drill horizontals
- predicting production rates
- predicting decline rates
- predicting EURs
- determining drainage areas (spacing units) in thick intervals of shale

Unknowns after 7500 wells
- what is the OGIP
- what is optimum interval to perf?
- what is the optimum frac design and number of stages and/or horizontal length?
- what is the drainage area/volume of our wells?
- what is the recovery factor?
- and what is the optimum spacing unit?

We do not understand these very complex rocks

- gas shale producers have no confidence in their OGIP calculations or do not believe them at all

-some numbers are ridiculously high or low

-desorption numbers commonly exceed adsorption numbers

-production data does not match OGIP

-micro seismic shows what fracs not what produces

Pore Structure Analyses

- **Microporosity:**
    - **CO_2 low pressure isotherm analysis (D-R method)**

- **Meso-macroporosity:**
    - **N_2 low pressure isotherm analysis (BET theory)**
    - **Hg porosimetry**

- **Open Porosity**
    - **He pycnometry**
    - **Hg immersion**

Implications of Pore Size Distribution- Sorbed Gas

- GIP- many companies measure using canister desorption as for CBM
- Desorbed gas is considered to be gas that was in the adsorbed state in the reservoir– **but is it?**

Remember
OGIP = Free Gas + Adsorbed Gas+ Solution Gas
What does it mean

- if it's assumed that desorbed gas = adsorbed gas
- free gas obtained from Sw and Porosity

total gas = desorbed + $\emptyset \times$(1-Sw) + solution

total gas is over estimated (i.e. double dipping the free gas)

Quantifying porosity and Sw
- well logs yield poor data in argillaceous strata- need lab measurements to calibrate logs
- commercial lab measures grain and/or skeletal density with He and Hg bulk density with Hg- **after** drying the sample
- sorbed gas occupies space
- what about pore compressibility

is the solution to use a larger gas molecule (i.e. Methane, Argon or Krypton)??

- all gases sorb (even He)

(we quantifying gas in experiment by correcting for Z)
if sorption takes place during the experiment
 = **wrong answer**
..... how wrong... depends on the sorption capacity of the rock (surface area) and gas in use.

And Hence
- porosity measurements using skeletal density measured by He too high (always)
- with other gases correction for sorption is mandatory
- correction for pore compressibility is a must and the error in porosity calculation also results in a humongous error in isotherm analyses where void volume is measured by He

The ability of gas to be produced from shales decreases markedly with increase in effective stress and hence depth (Kvert <<< Khorz). Based on a series of diffusion/flow experiments under triaxial (reservoir) conditions, we show that gas released from the matrix is strongly stress dependent and occurs at rates that in many shale reservoirs with wide fracture spacing is production-limiting.

Shale Gas Opportunities and Challenges

R. Marc Bustin

A. Bustin, D. Ross, G.Chalmers,
V. Murthy, Laxmi, C., Cui. X.

Earth and Ocean Sciences
UBC
UBC

CBM Solutions

TRICAN
WELL SERVICE

Definition: Gas Shale

- Shale gas is defined as a fine-grained reservoir in which gas is self sourced and some of the gas is stored in the sorbed state

- Sorbed gas is predominantly stored in the organic fraction– so organics present

- Not just 'shale'

Bustin, 2005, AAPG

technology

price

High Quality	1000 md
Medium Quality	100 md
Tight Gas Sands	1 md
CBM Gas Shale Low Quality	
Low Btu Gas Hydrates / Other	0.00001 md
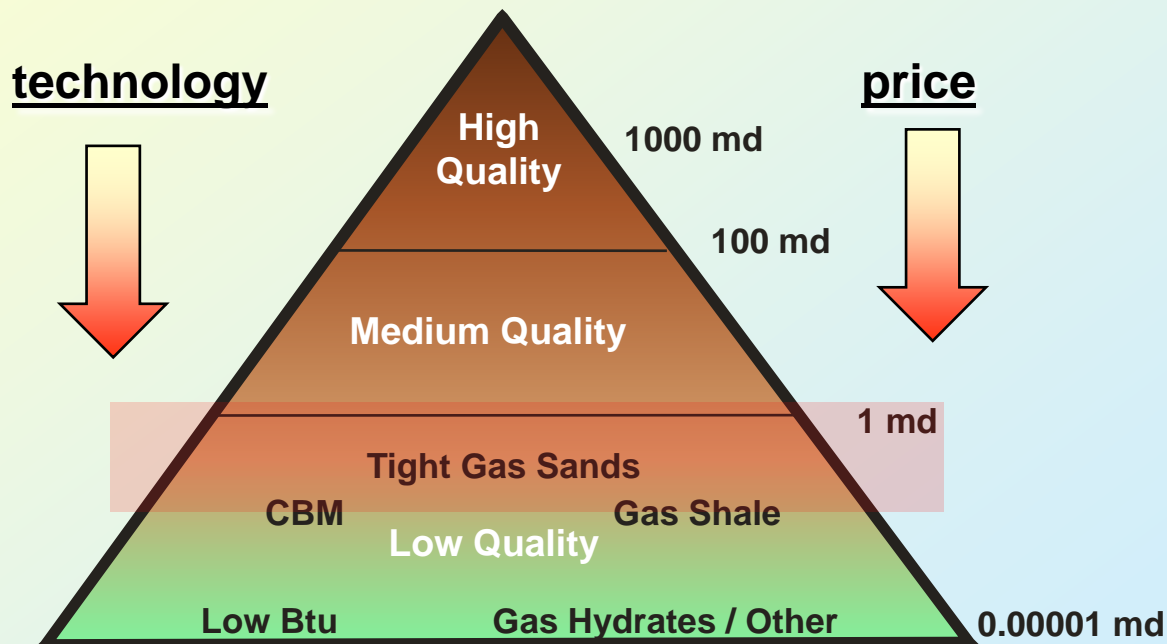
Background

outline

- what's happening
- what we think we know
- what we don't know some of which we may think we know
- what we need to know

Gas Shale Basins of the United States

Bakken
Gammon
Niobara
Green River
Monterey
McClure
Cane Creek
Lewis and Mancos
Barnett and Woodford
Palo Duro
Barnett
Woodford
Antrim
Devonian/Ohio
New Albany
Fayetteville
Floyd and Conasauge
Caney and Woodford
Excello/Mulky

Background

Gas Shale Basins of the United States

Bakken

Gammon

Niobara

Green River

Monterey

McClure

Cane Creek

Lewis and Mancos

Barnett and Woodford

Palo Duro

Barnett

7500 prod. Wells

≈ 1 TCF/year

Woodford

Antrim

Devonian/Ohio

New Albany

Fayetteville

Floyd and Conasauge

Caney and Woodford

Excello/Mulky

Background

Gas Shale Basins of the United States

Bakken
Gammon
Niobara
Green River
Monterey
McClure
Cane Creek
Lewis and Mancos
Barnett and Woodford
Palo Duro
Barnett
Woodford
Excello/Mulky
Caney and Woodford
Floyd and Conasauge
Fayetteville
New Albany
Devonian/Ohio
Antrim

Background

Gas Shale Basins of the United States

Bakken
Gammon
Niobara
Green River
Monterey
McClure
Cane Creek
Lewis and Mancos

Antrim
Devonian/Ohio
New Albany
Fayetteville
Floyd and Conasauge
Caney and Woodford

750 Fayetteville wells

400 Woodford wells

Barnett and Woodford
Palo Duro
Barnett
Woodford
Excello/Mulky

Background

Sedimentary Basins and Major Shale Sequences of Canada

Boas River

Boas River

Shaftsbury
Moosebar/
Buckinghorse
Dunvegan

Muskwa-
Fort Simpson
Besa River

Duvernay
Ireton

Exshaw-
Bakken-Banff

Green Point-
Curling Group

Table Cove-Black
Cove-Winterhouse

Macasty-
Vaureal

Montney-
Grayling-
Phroso-Vega-
Doig-Phosphatic-
Toad-Whistler

Nordegg-Gordondale-
Fernie-Rierdon

Long Rapids

Pointe Blue

Ultica-
Loraine

Dawson
Point

Collingwood-
Blue Mountain

Marcellus

Kettle Point

Eastview-
Billings

Strathlorne-Albert
Cape Rouge-Hastings-
Cape Dauphin-West Bay
Rocky Brook

Background

modified form Hamblin, 2006

Sedimentary Basins and Major Shale Sequences of Canada

EOG (6 TCF)
Apache (9-16 TCF)

FOREST- UTICA SHALE- 4.1 TCF

Boas River

Boas River

Boas River

Shaftsbury
Moosebar/
Buckinghorse
Dunvegan

Muskwa-
Fort Simpson
Besa River

Duvernay
Ireton

Exshaw-
Bakken-Banff

Montney-
Grayling-
Phroso-Vega-
Doig-Phosphatic-
Toad-Whistler

Nordegg-Gordondale-
Fernie-Rierdon

Long Rapids

Dawson
Point

Collingwood-
Blue Mountain

Kettle Point

Table Cove-Black

Vaureal

Pointe

Ultica
Loraine

Eastview-
Billings

Marcellus

Green Point-
Curling Group

Strathlorne-Albert
Cape Rouge-Hastings-
Cape Dauphin-West Bay
Rocky Brook

Background

modified form Hamblin, 2006

what we know- gas shales

- productive gas shales range from organic-rich, fine-grained rocks ,such as the Antrim or Ohio Shale to variable facies rocks, such as Lewis Shale
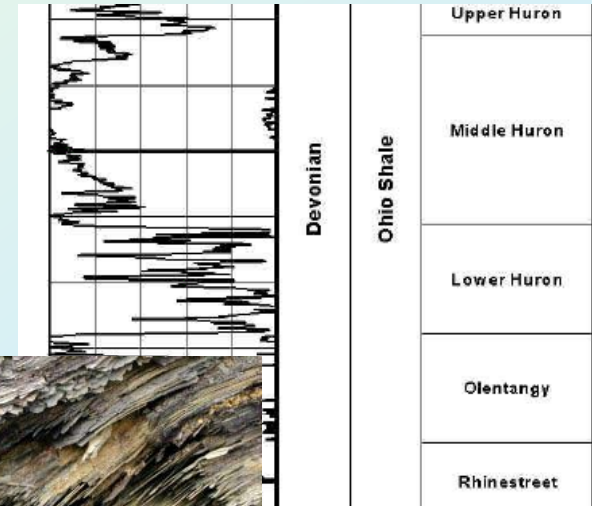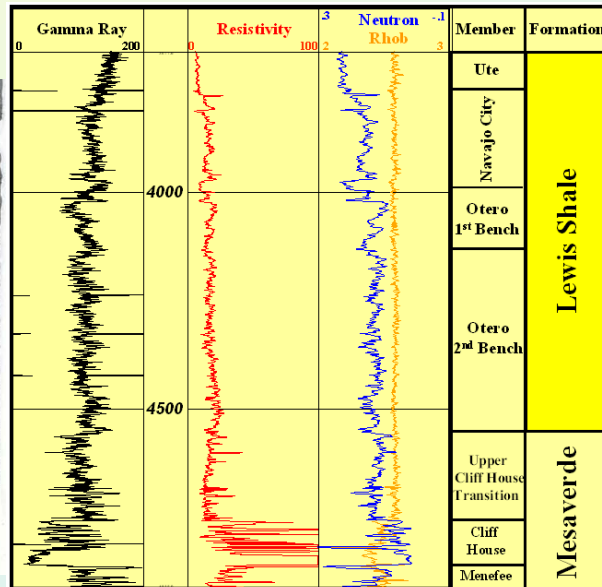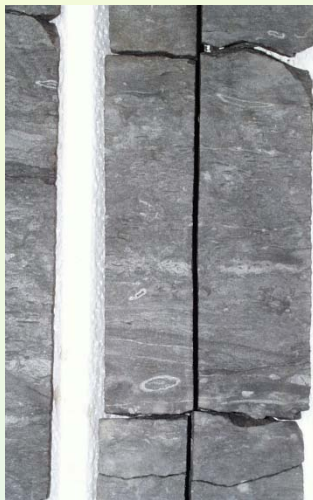
Antrim

New Albany

Barnett

Ohio

Lewis

SOME EXAMPLES

Background

Carbonate-Rich

SiO$_2$ = 60.7 %
Al$_2$O$_3$ = 16.9 %
CaO = 1.69 %
Porosity = 6.4 %

SiO$_2$ = 5.5 %
Al$_2$O$_3$ = 1.7 %
CaO = 44.5 %
Porosity = 1.42 %

SiO$_2$ = 7.9 %
Al$_2$O$_3$ = 1.7 %
CaO = 47.9 %
Porosity = 0.7 %

SiO$_2$ = 30 %
Al$_2$O$_3$ = 3.0 %
CaO = 20 %
Porosity = 0.35 %

Incremental Intrusion (mL/g)

0.0035
0.003
0.0025
0.002
0.0015
0.001
0.0005
0

Pore SIze Diameter (nm)

1000000   100000   10000   1000   100   10   1
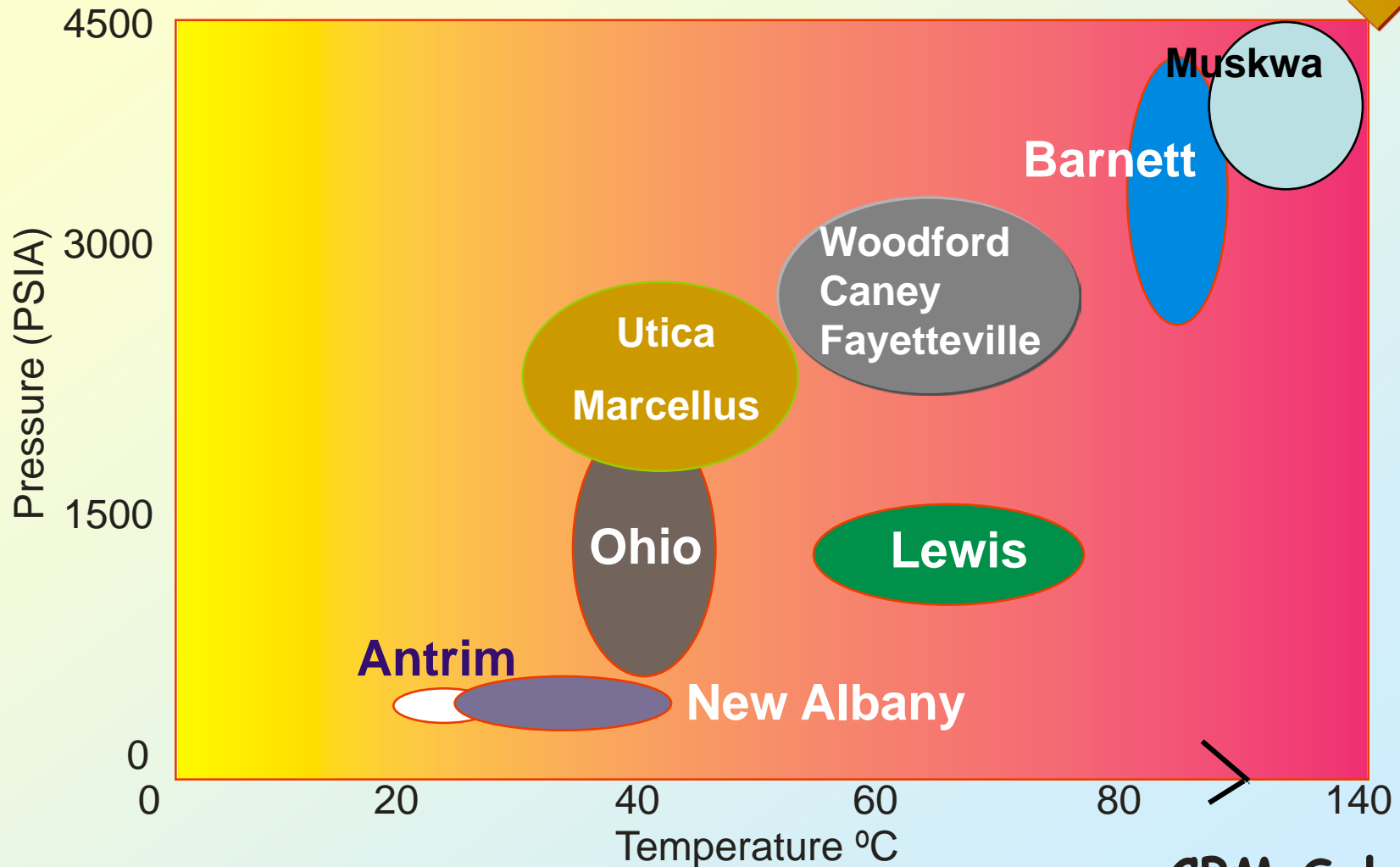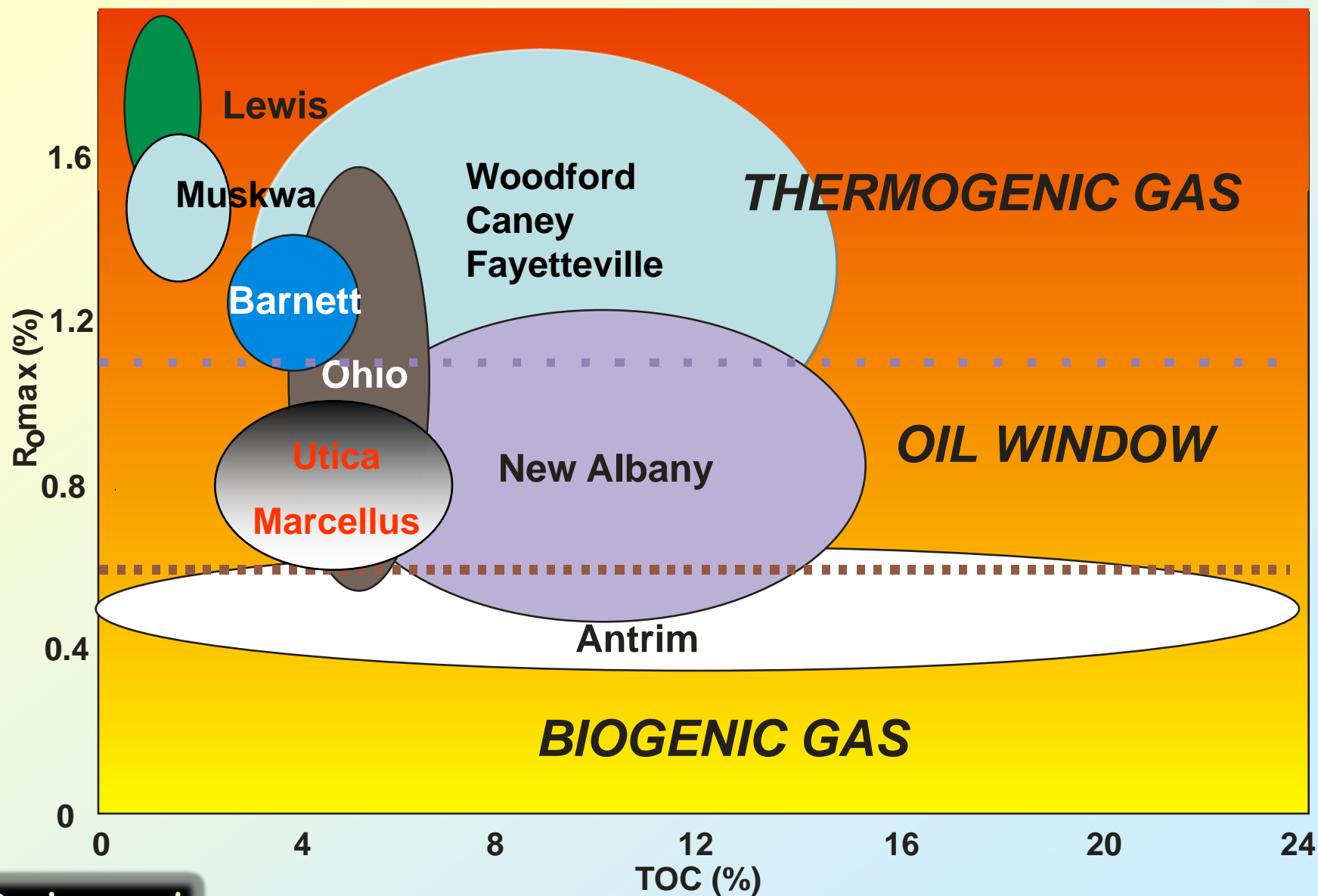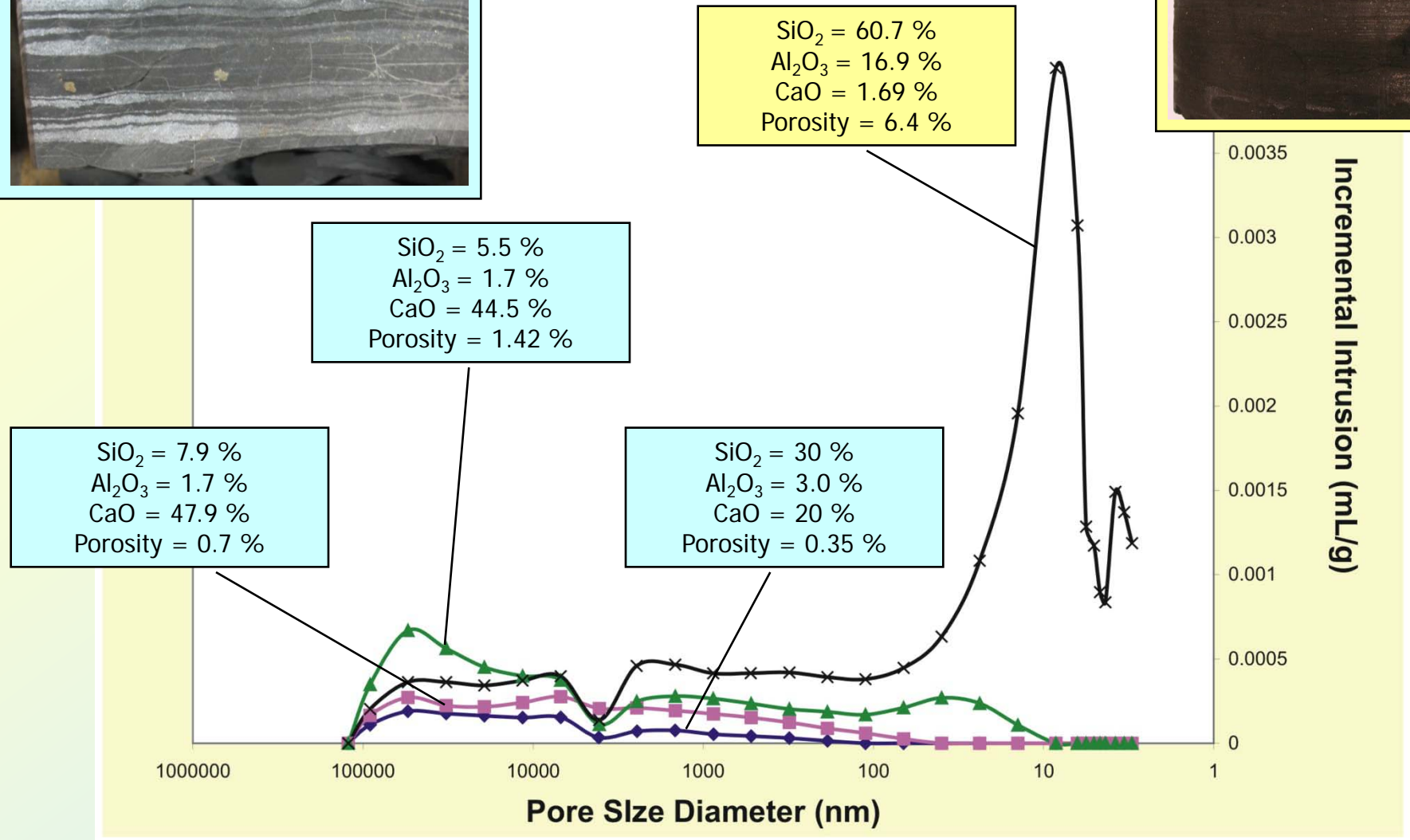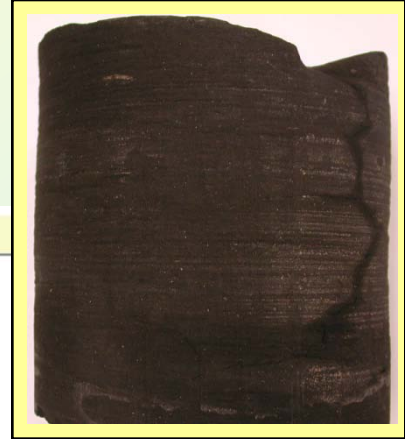
Clays and Total Porosity
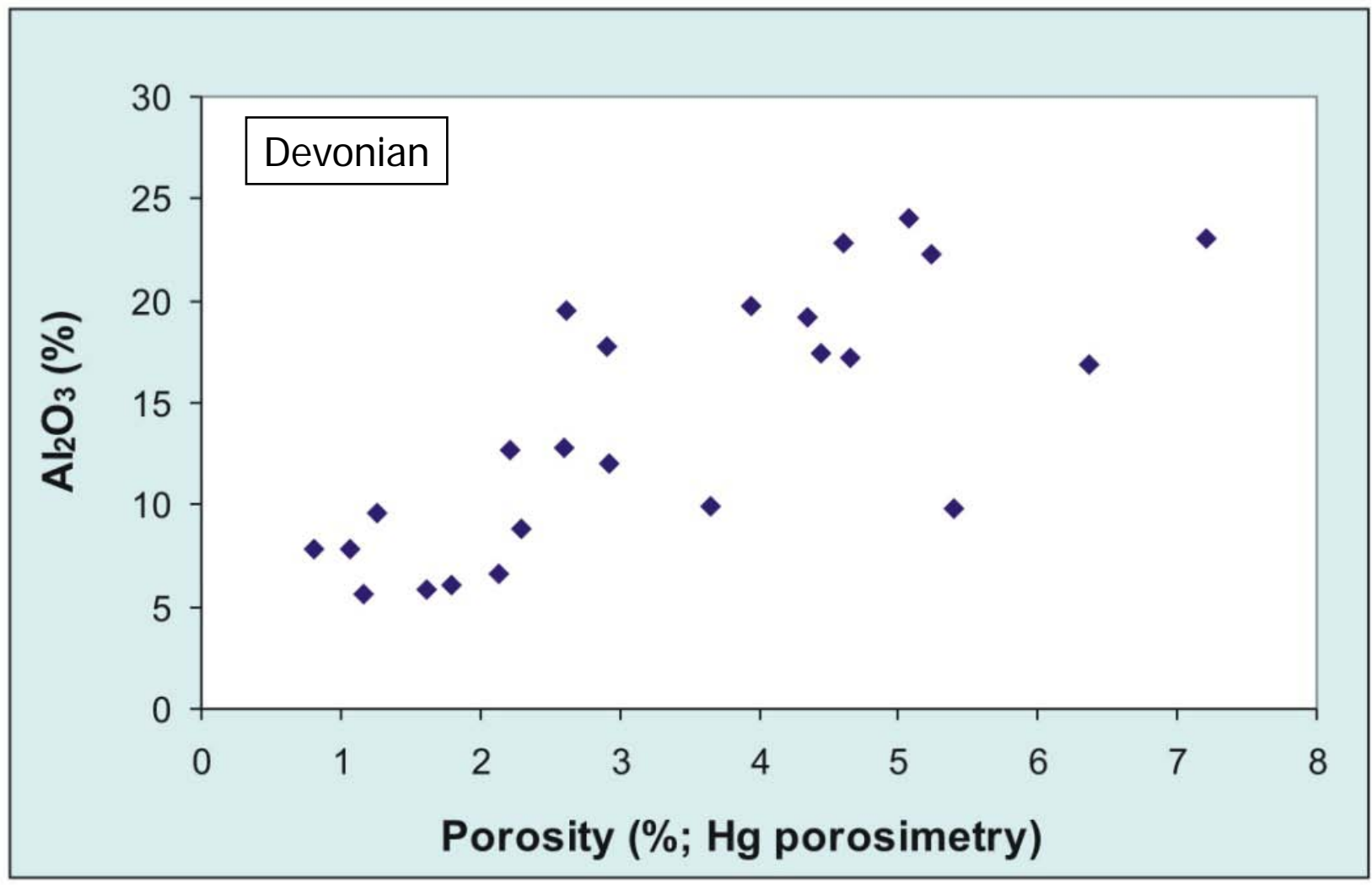
Biogenic Silica and Porosity

SiO_2 = 80 %
Al_2O_3 = 7 %
TOC = 2.2 wt%
Av Ø = 1.07 %

SiO_2 = 73 %
Al_2O_3 = 11.2 %
TOC = 2.8 wt%
Av Ø = 2.61 %

SiO_2 = 57.1 %
Al_2O_3 = 19.5 %
TOC = 3.32 wt%
Av Ø = 6.55 %
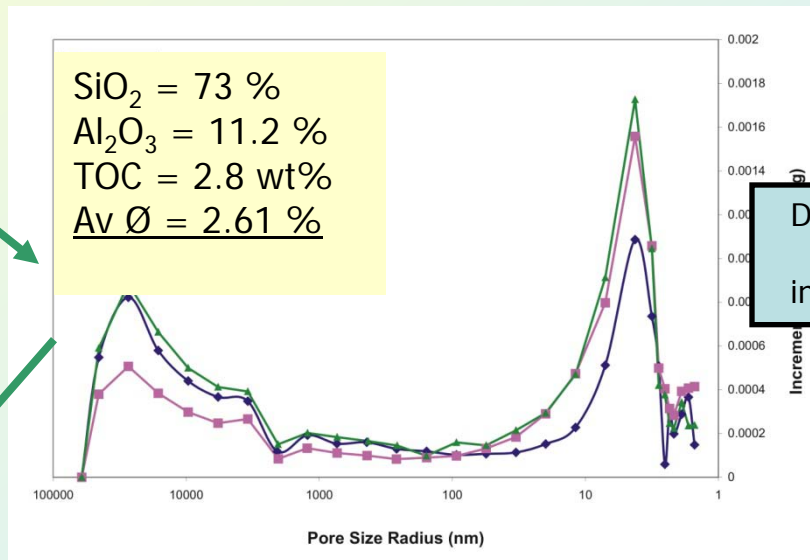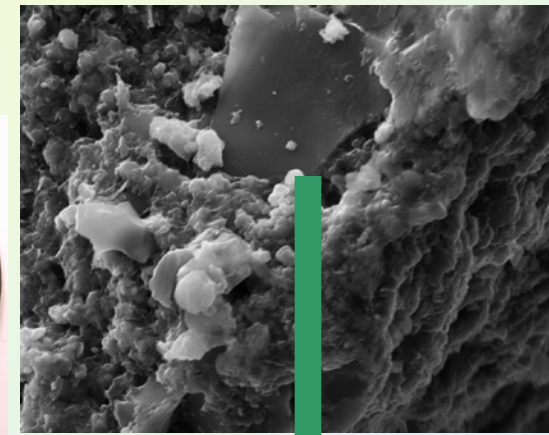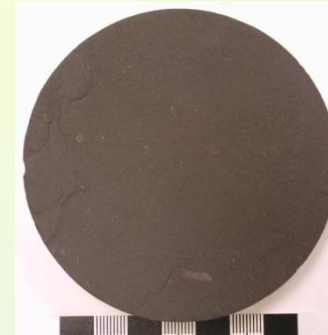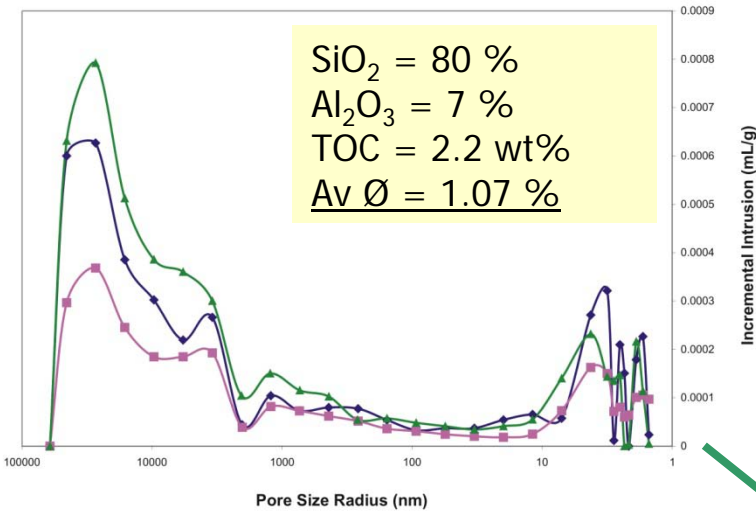
Decreasing SiO_2
and
increasing Al_2O_3

Silica and Porosity

SiO$_2$ = 80 %
Al$_2$O$_3$ = 7 %
TOC = 2.2 wt%
Av Ø = 1.07 %
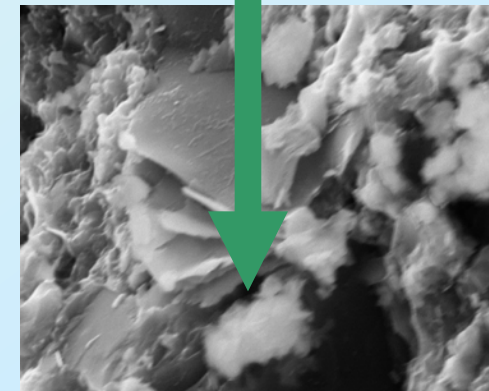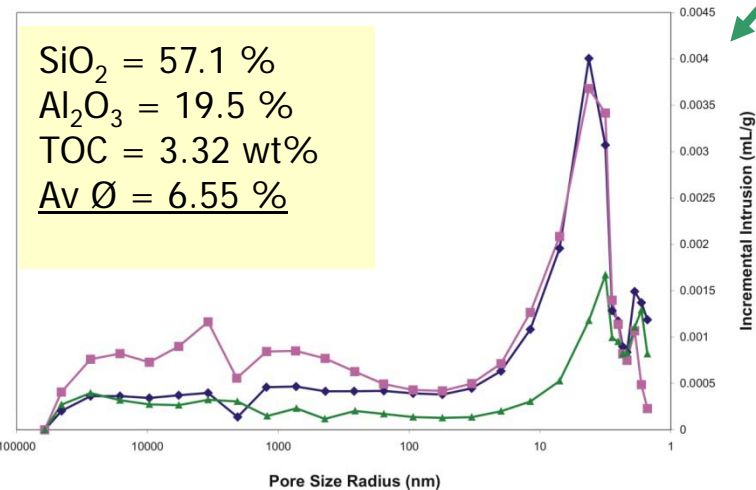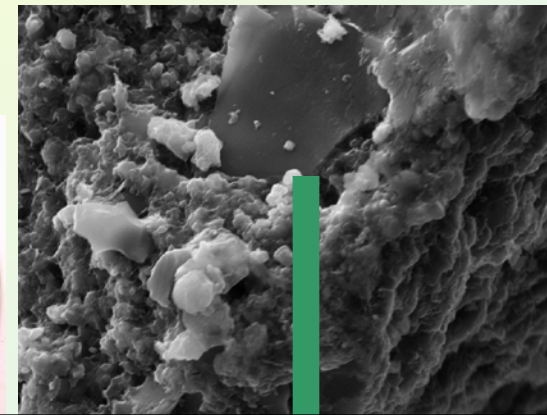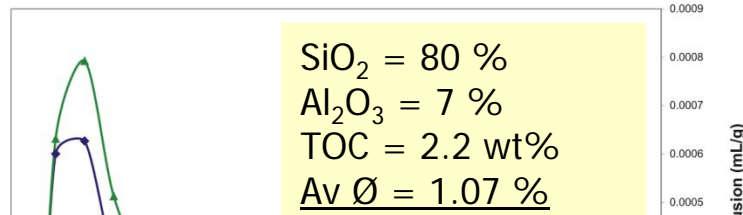
conclusion- pore size in fine-grained rocks is really small,
Pore-size distribution is variable
porosity is variable (order of magnitude variation)
reflects mineralogy and fabric

SiO
Al$_2$O$_3$ = 19.3 %
TOC = 3.32 wt%
Av Ø = 6.55 %

Incremental Intrusion (mL/g)
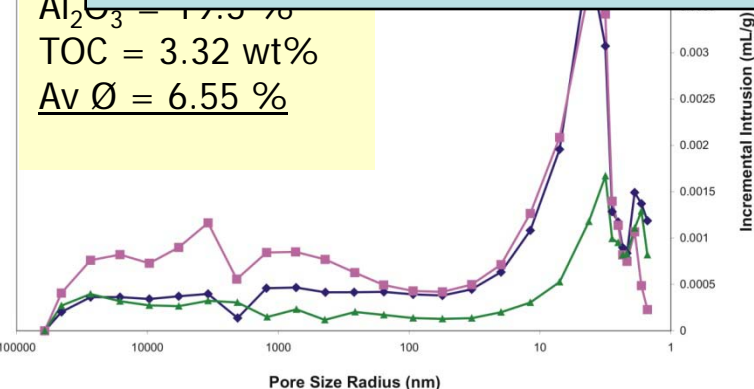
Pore Size Radius (nm)

Pore Size Radius (nm)
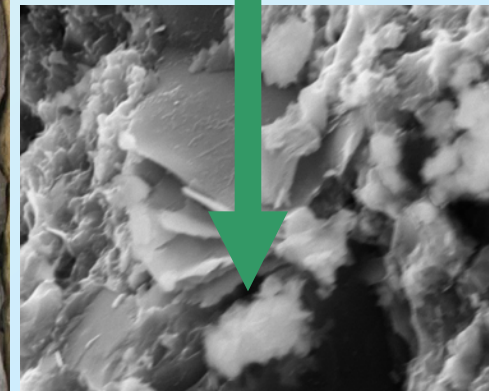
DETRITAL VS BIOGENIC QUARTZ

MUSKWA

Moosebar

Barnett
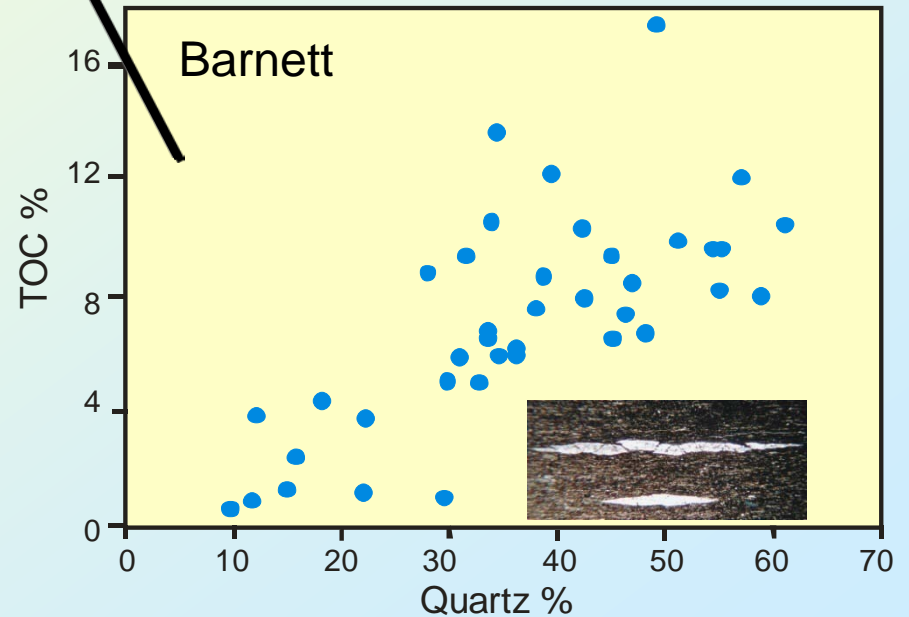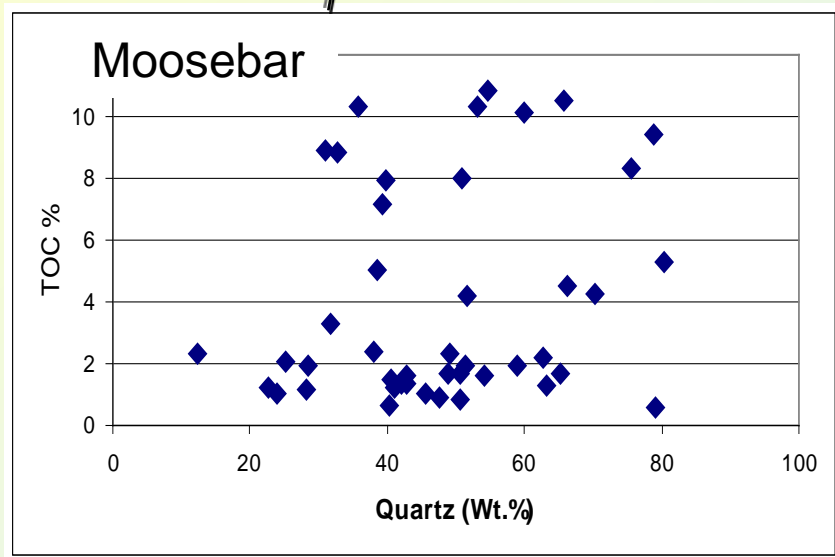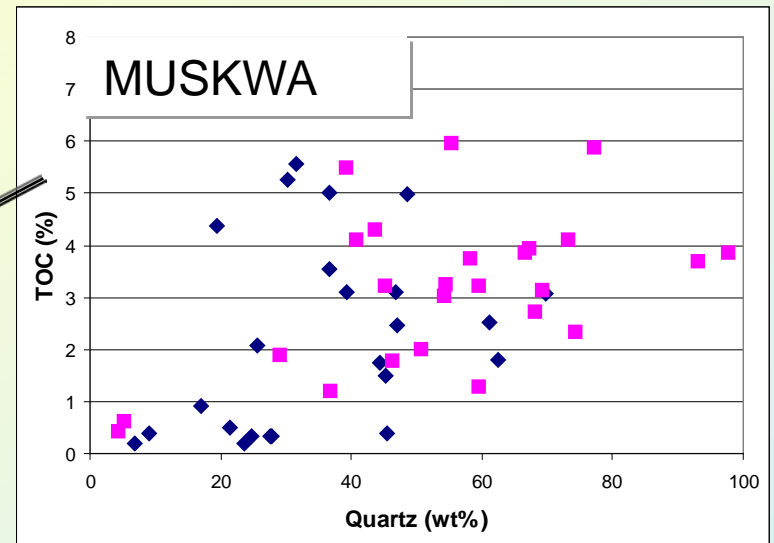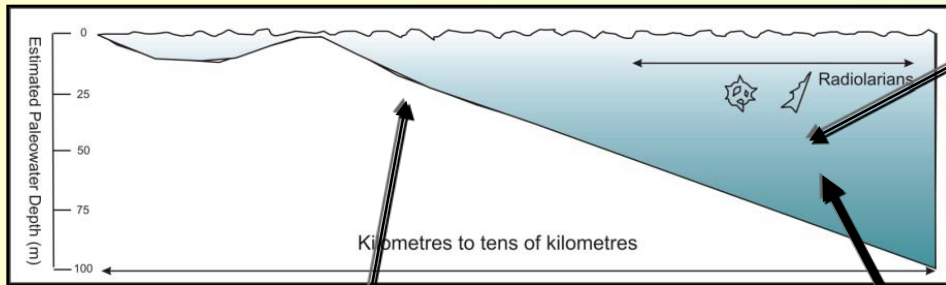
- Detrital Si source

- Biogenic Si source from radiolarians

Maturity and TOC Effect
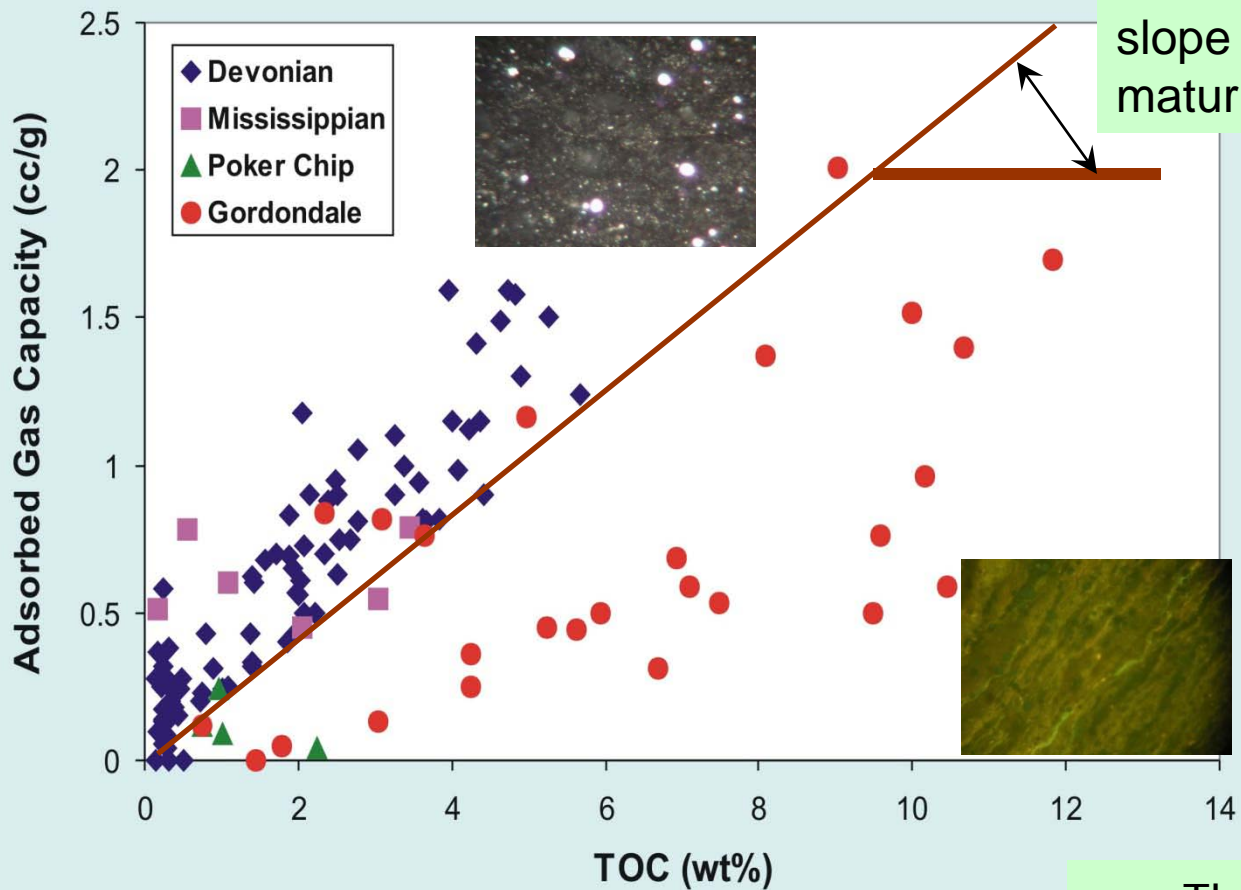
slope is proportional to maturity/kerogen type

Thermal maturation structurally transforms organic fraction, creating more microporosity, hence potential adsorption sites

Gas in Place- adsorption

complexities and predictions
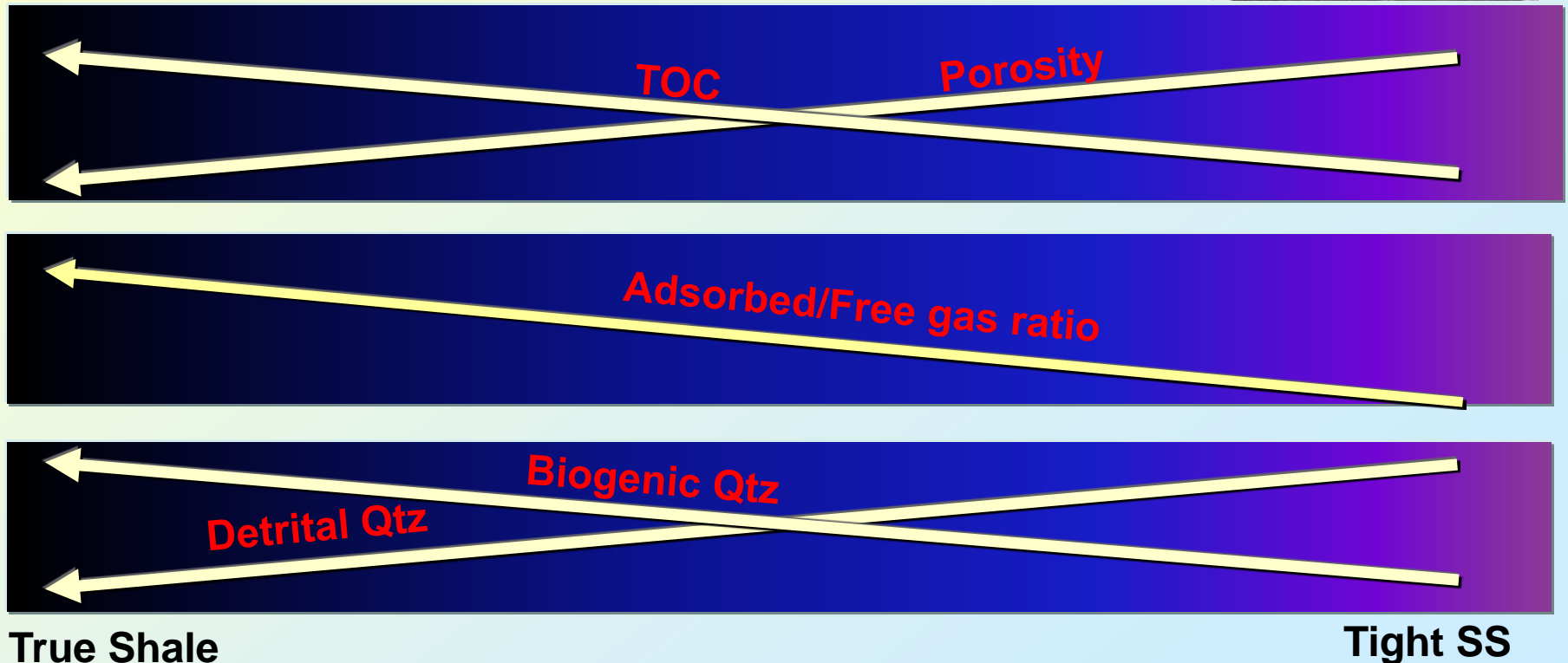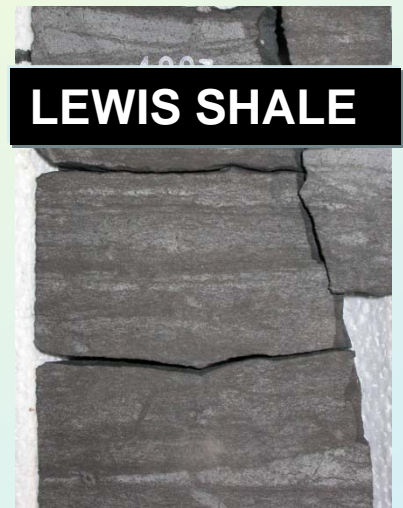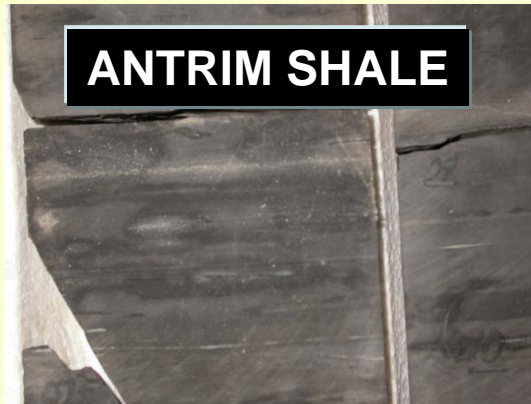
RESERVOIR ACCESS: Ability to Frac or potential to be naturally fractured
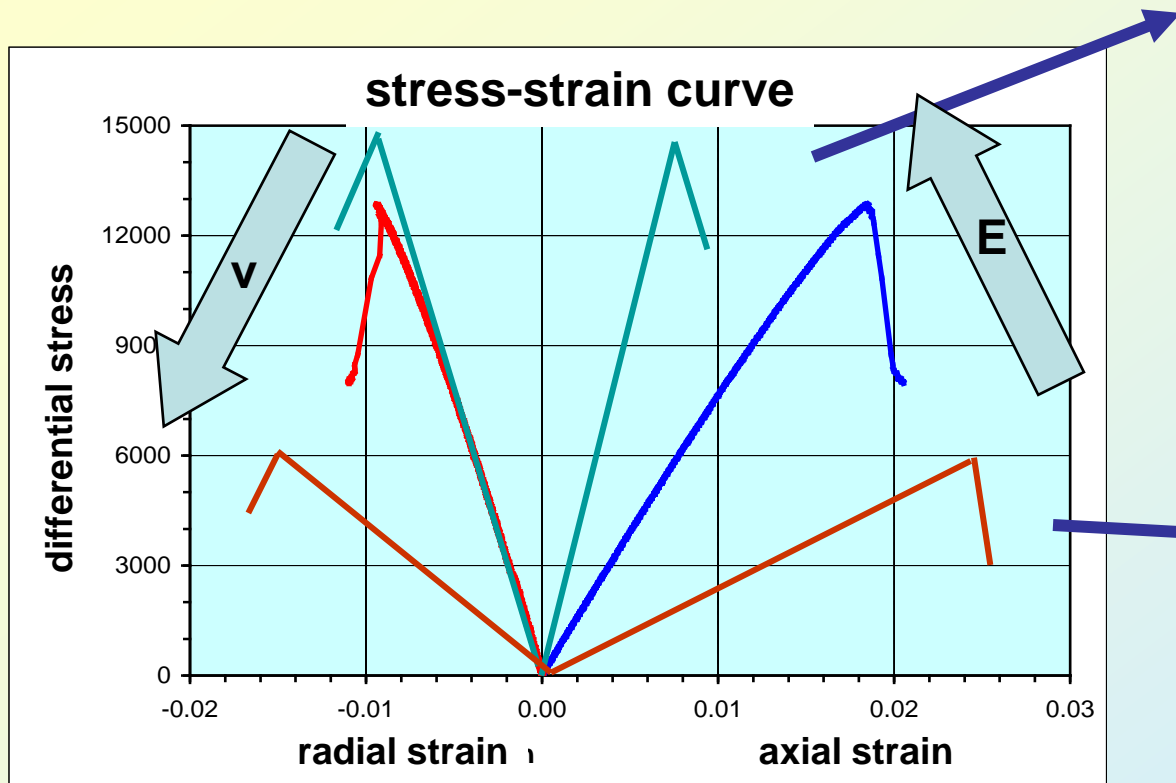
Failure mode- E and v vary with mineralogy and fabric f(sedimentology, provenance, diagenesis, tectonics)

deliverability

Ability to Frac
or to be naturally fractured

stress-strain curve

Failure mode- E and ν vary with mineralogy and fabric f(sedimentology, provenance, diagenesis, tectonics)

deliverability

Fabric Implications

Woodford Shale – gas does not bleed out of the matrix uniformly despite the macroscopic homogeneity
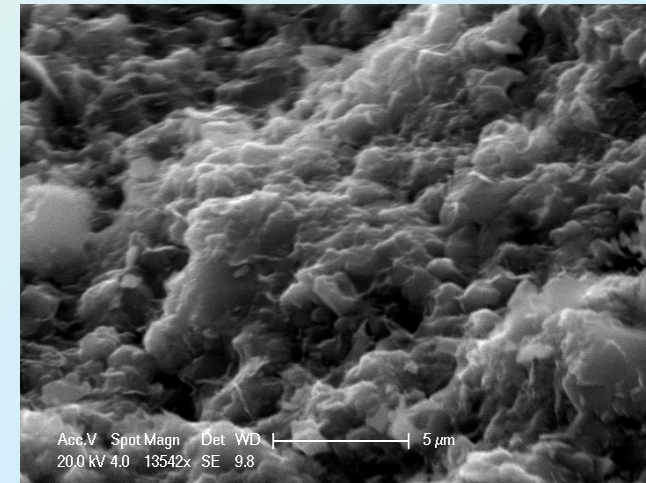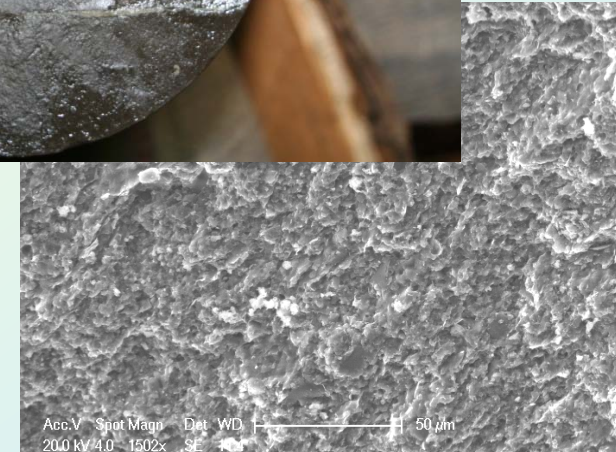
deliverability

Shales are heterogeneous rocks

outcrop

Hand
Spec.

200 000 nm

Light

50 000 nm
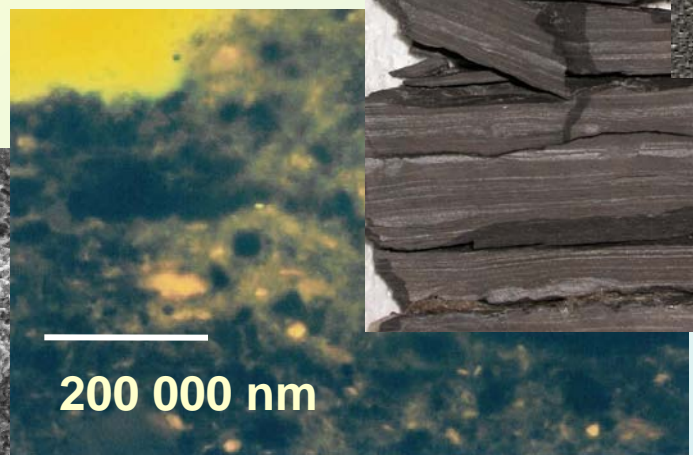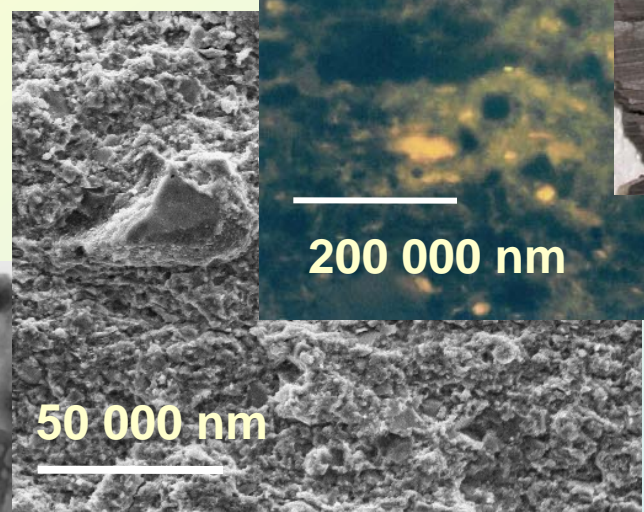
SEM

Transmission Electron Microscope

200 nm

CBM Solutions

Background

general observations
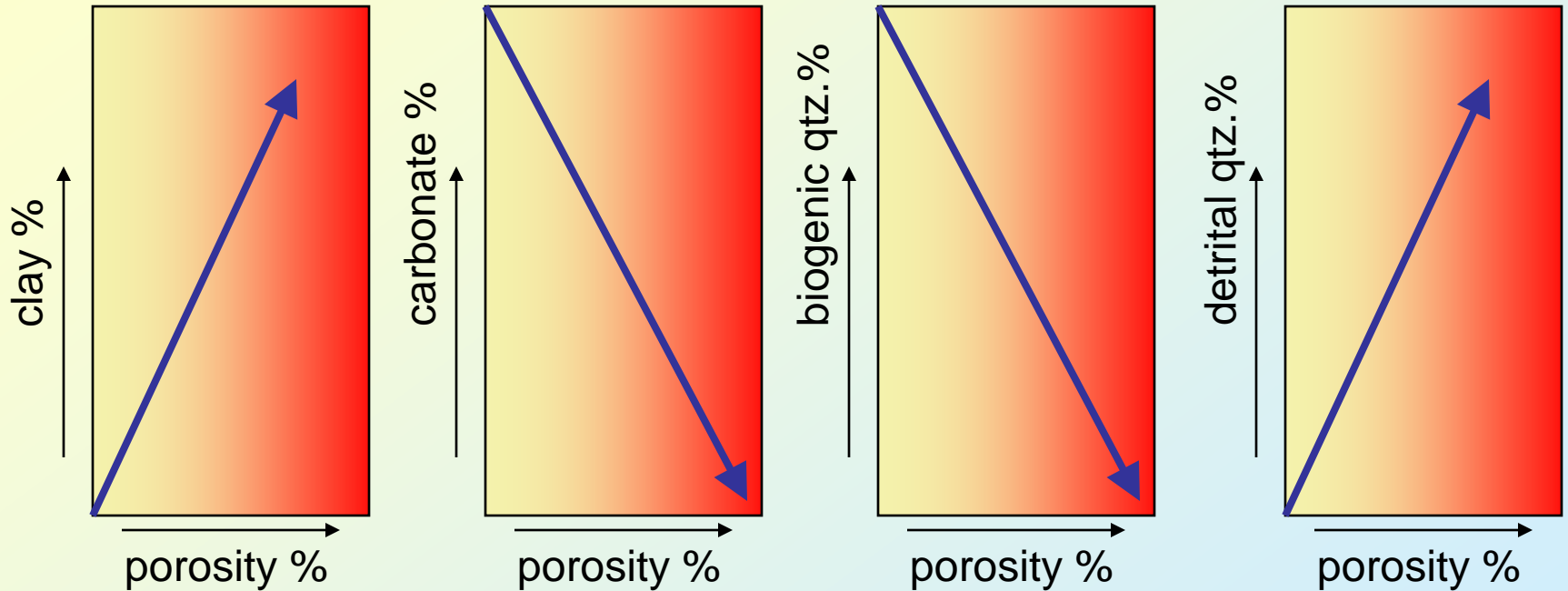
- porosity decreases with diagenesis and effective stress

- quartz may be positively (biogenic) or negatively (detrital) correlated with TOC

more siliceous and silicified shales are more brittle
than clay, organic- or carbonate-rich shales and have greater propensity
to be fractured and to be fraced
(greater Young's modulus and lower Poisson's Ratio)
BUT TOO SILICOUS = NO K or Porosity

CRITICAL TO DEFINE MECHANICAL STRATIGRAPHY

%

quartz

clay

Poisson's Ratio

Young's Modulus

degree

diagenesis

Mixed lattice
illite-smectite

Solid state
transformation

Pure illite

Poisson's Ratio

Young's Modulus
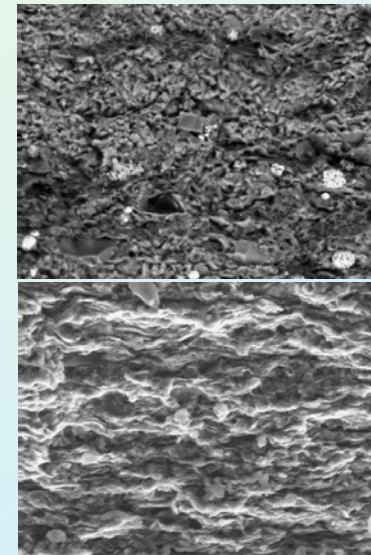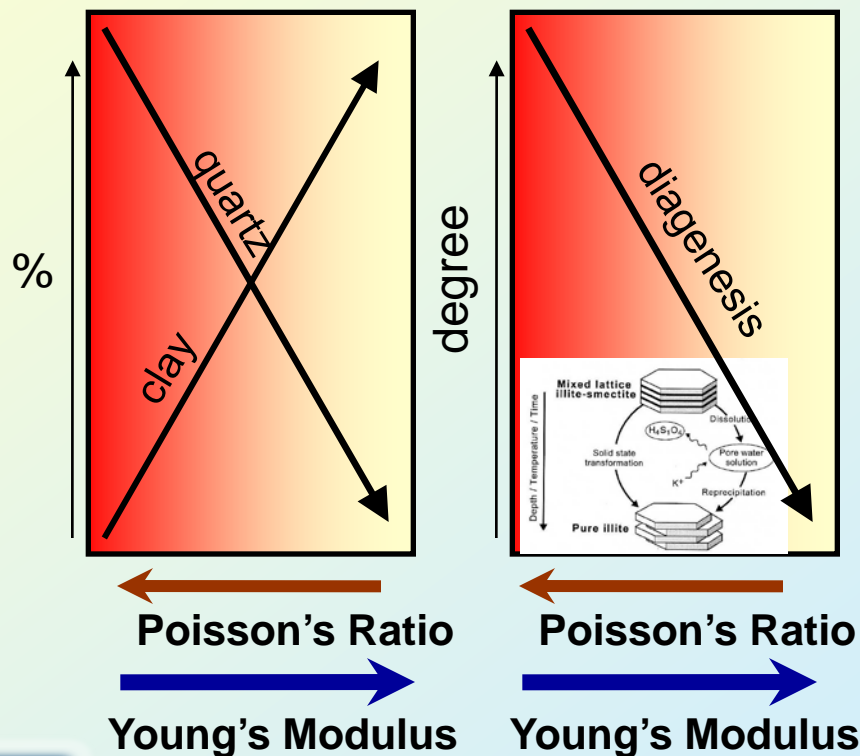
contrast in fabric of
biogenic vs
detrital qtz-rich shales

deliverability

Matrix porosity

Matrix Perm.

Maturity

In Situ Stress

Pressure

Rock Mechanics
E

Rock Mechanics
v

Depth\Diagenesis

PROSPECT WINDOW

summary

In Situ Stress

Pressure

Rock Mechanics E

v

Sorbed

Free

GIP

Res. Access/ Deliverability

background- learnings to date

thick sequences of shale with variable amounts of gas exist in many/most basins

shales are extremely heterogeneous in their properties but at a scale not generally considered

early views that organic geochemistry is "the" screen for prospectively is proving incorrect

evaluating gas in place and testing productivity by drilling and fracing is expensive- clear need for exploration/development model

main risk is reservoir access- and mechanical stratigraphy

CBM Solutions

the challenges

- screening exploration targets
- determining intervals to frac or drill horizontals
- predicting production rates
- predicting decline rates
- predicting EURs
- determining drainage areas (spacing units)

challenges

in thick intervals of shale...

Unknowns after 7500 wells

- what is the OGIP

- what is optimum interval to perf?

- what is the optimum frac design and number of stages and/or horizontal length?

- what is the drainage area/volume of our wells?

- what is the recovery factor?

- and what is the optimum spacing unit?

BARNETT SHALE
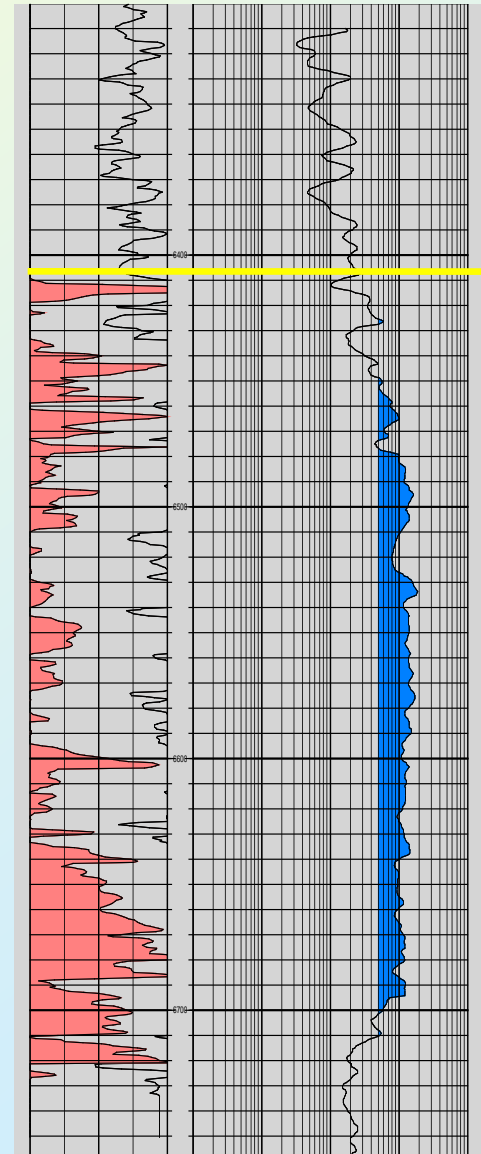
challenges

Gas Shale Model

ross

fundamental challenges

- gas in place
- matrix permeability

permeability diffusion

gas in place

Reservoir exploration and development

gas in place

deliverability

challenges
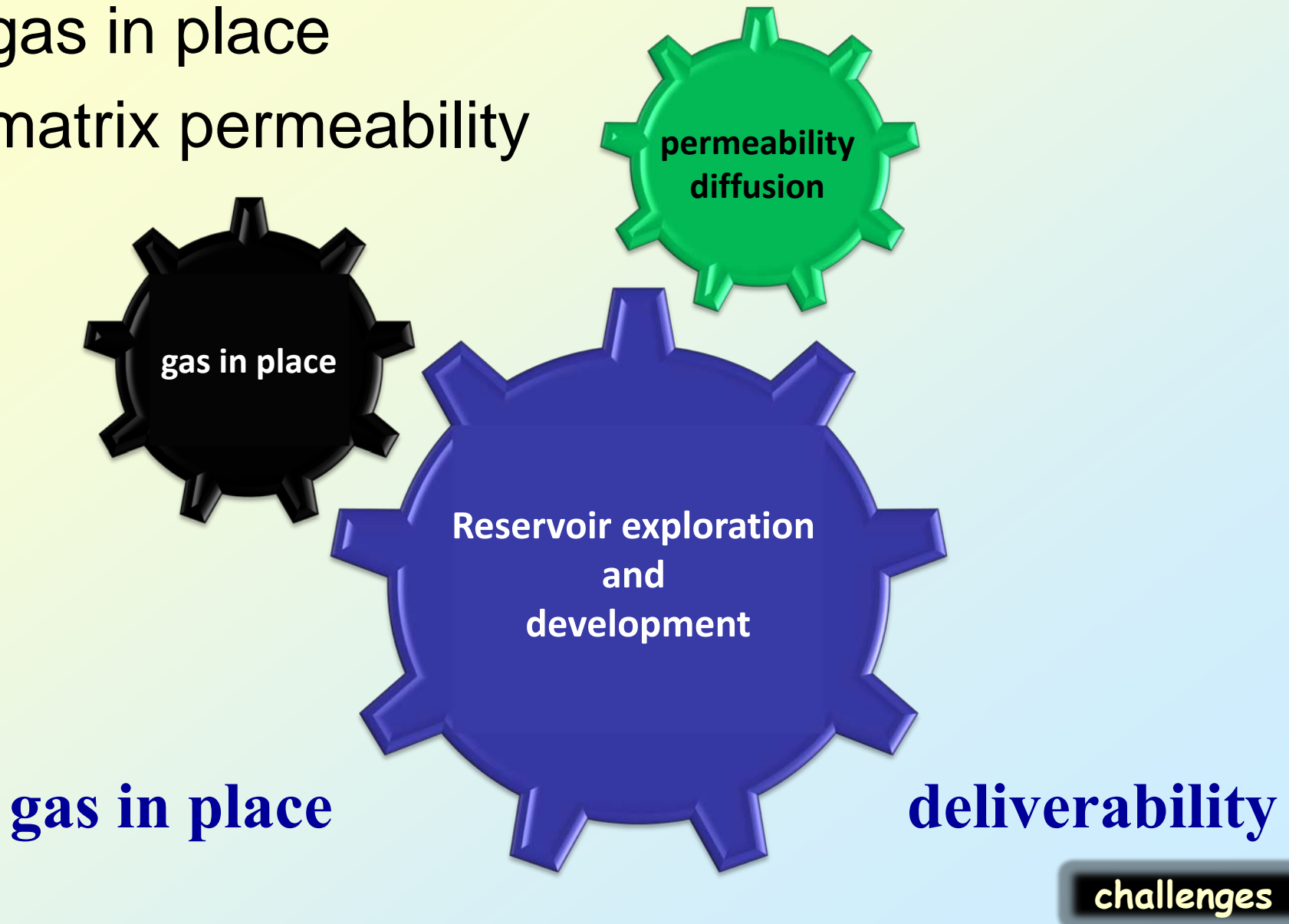
the emperor has no clothes!
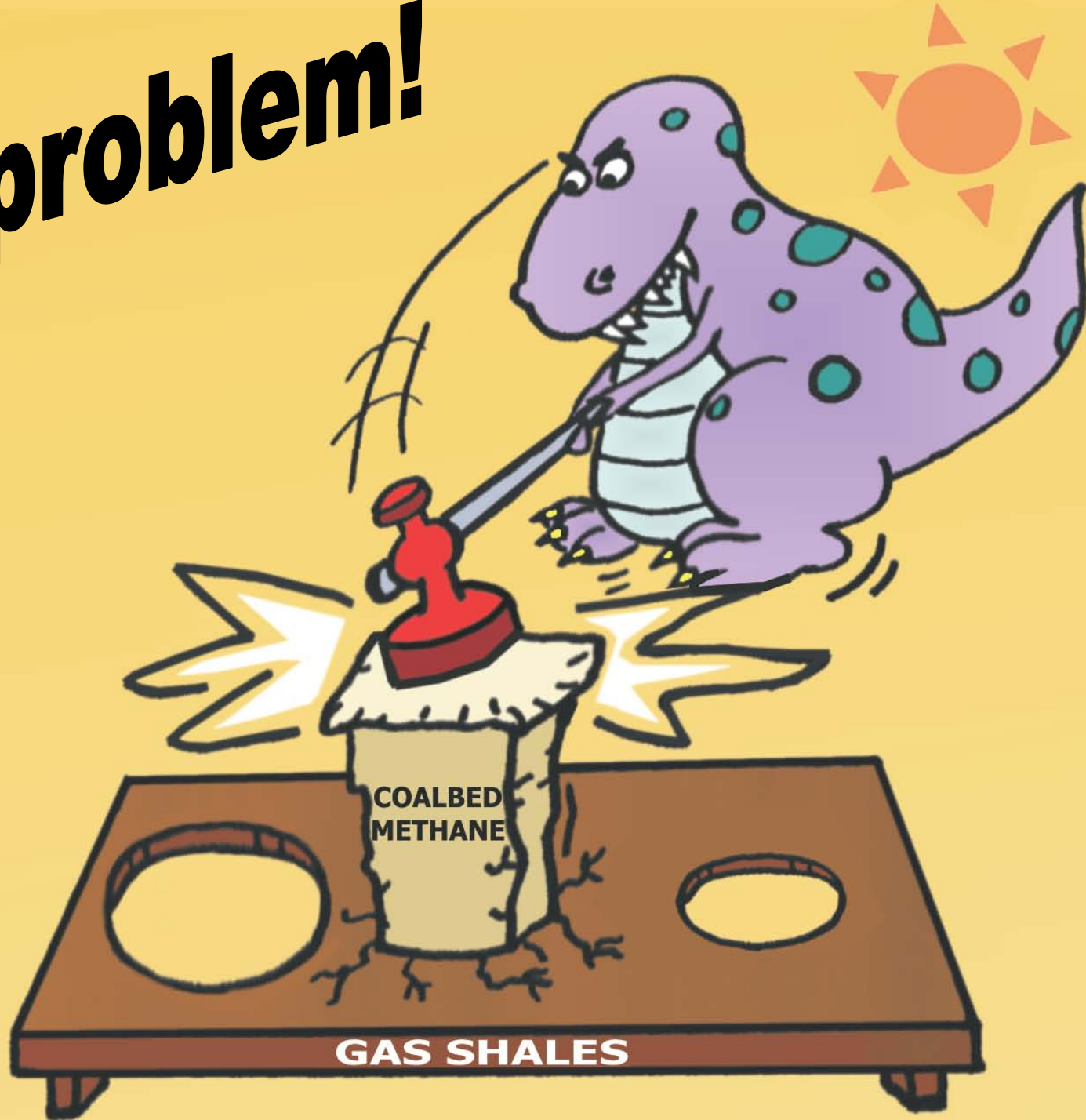
we do not understand these very complex rocks

- gas shale producers have no confidence in their OGIP calculations, or they do not believe them at all

-some numbers are ridiculously high or low

-desorption numbers commonly exceed adsorption numbers

-production data does not match OGIP
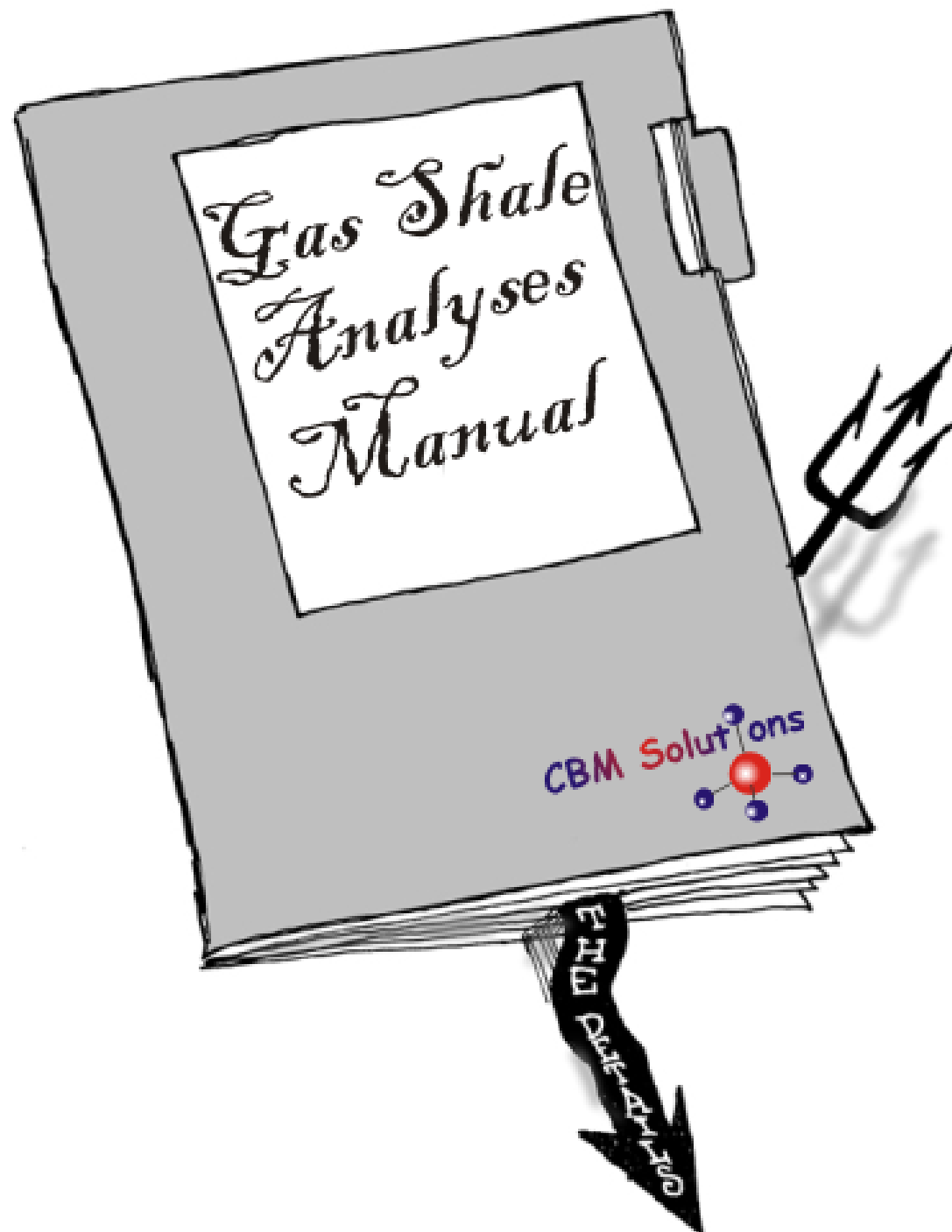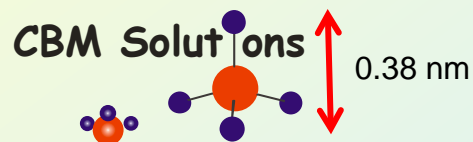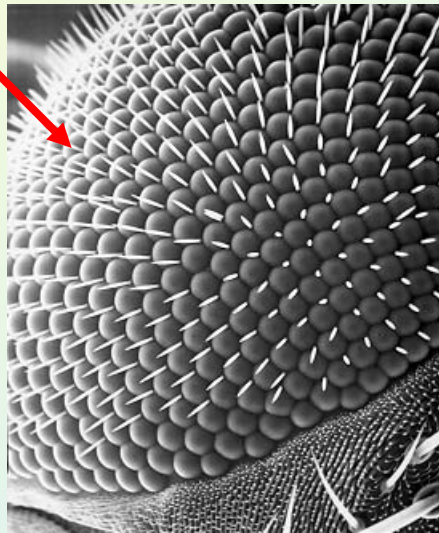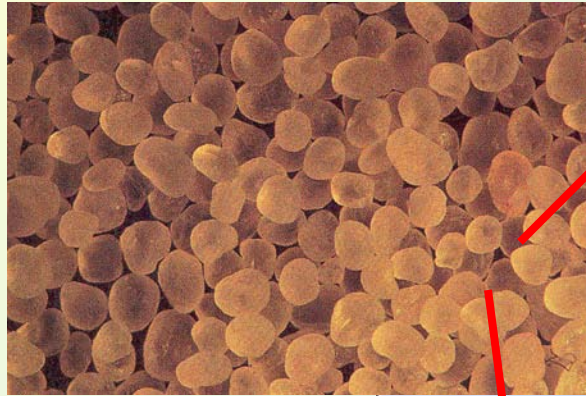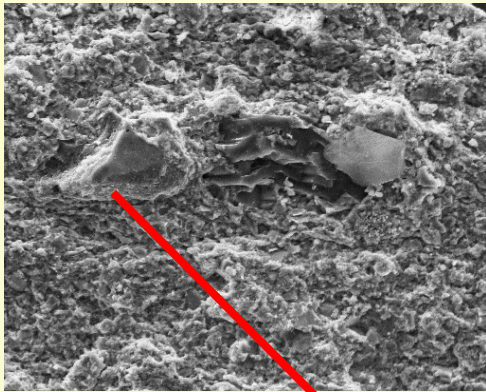
-micro seismic shows what fracs not

what produces

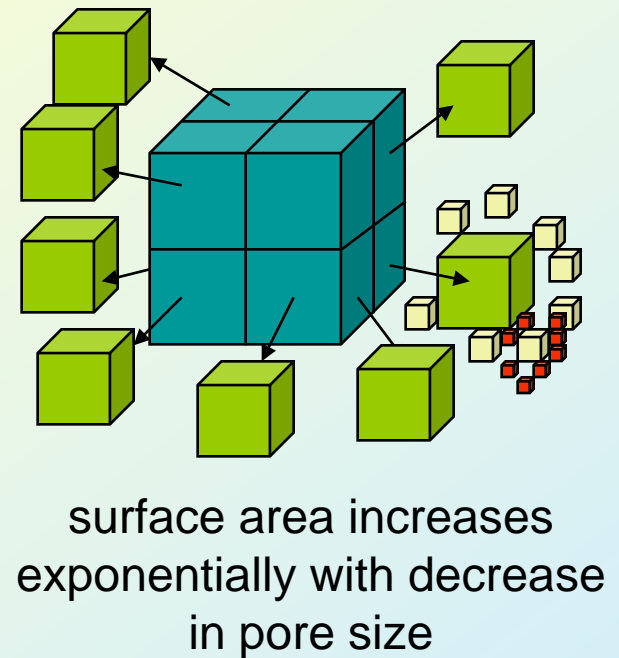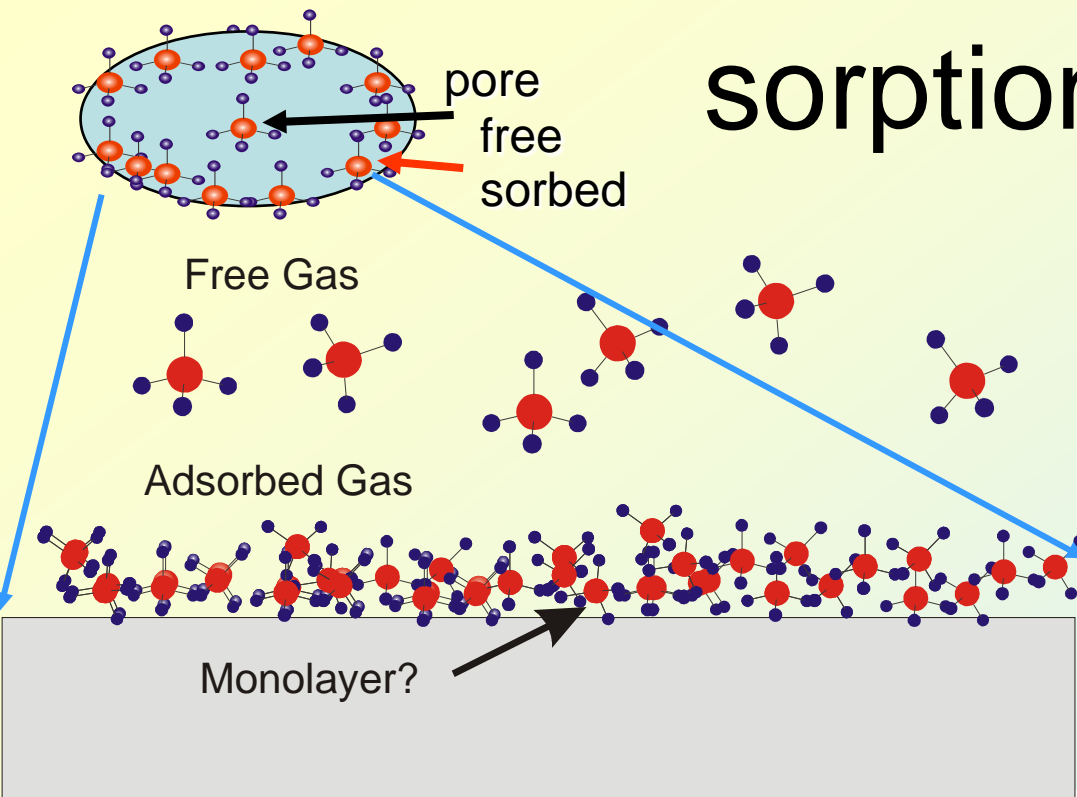how small are pores gas shales
– real small

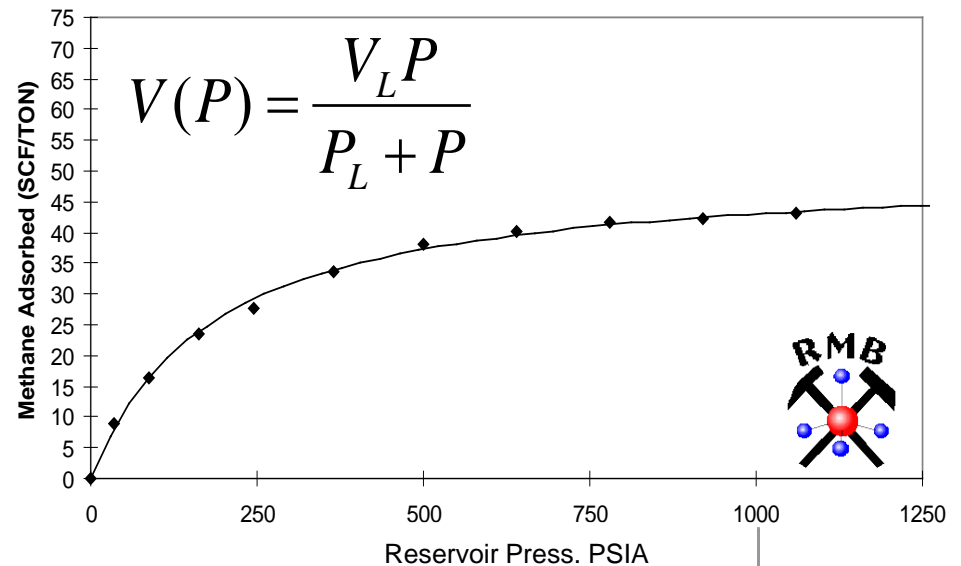Sandstone average
pore diameter ~ 1 mm

300 m

0.38 nm

Organic Matter pore diameter ~ .5 to 100 nm

Gas in Place- adsorption

sorption

pore
free
sorbed

Free Gas

Adsorbed Gas

Monolayer?

surface area increases
exponentially with decrease
in pore size

FESEM

$$V(P) = \frac{V_L P}{P_L + P}$$

S4700 2.0kV 5.2mm x35.0k SE(U) 2/9/06   1.00um

Gas in Place- adsorption

Methane Adsorbed (SCF/TON)

Reservoir Press. PSIA
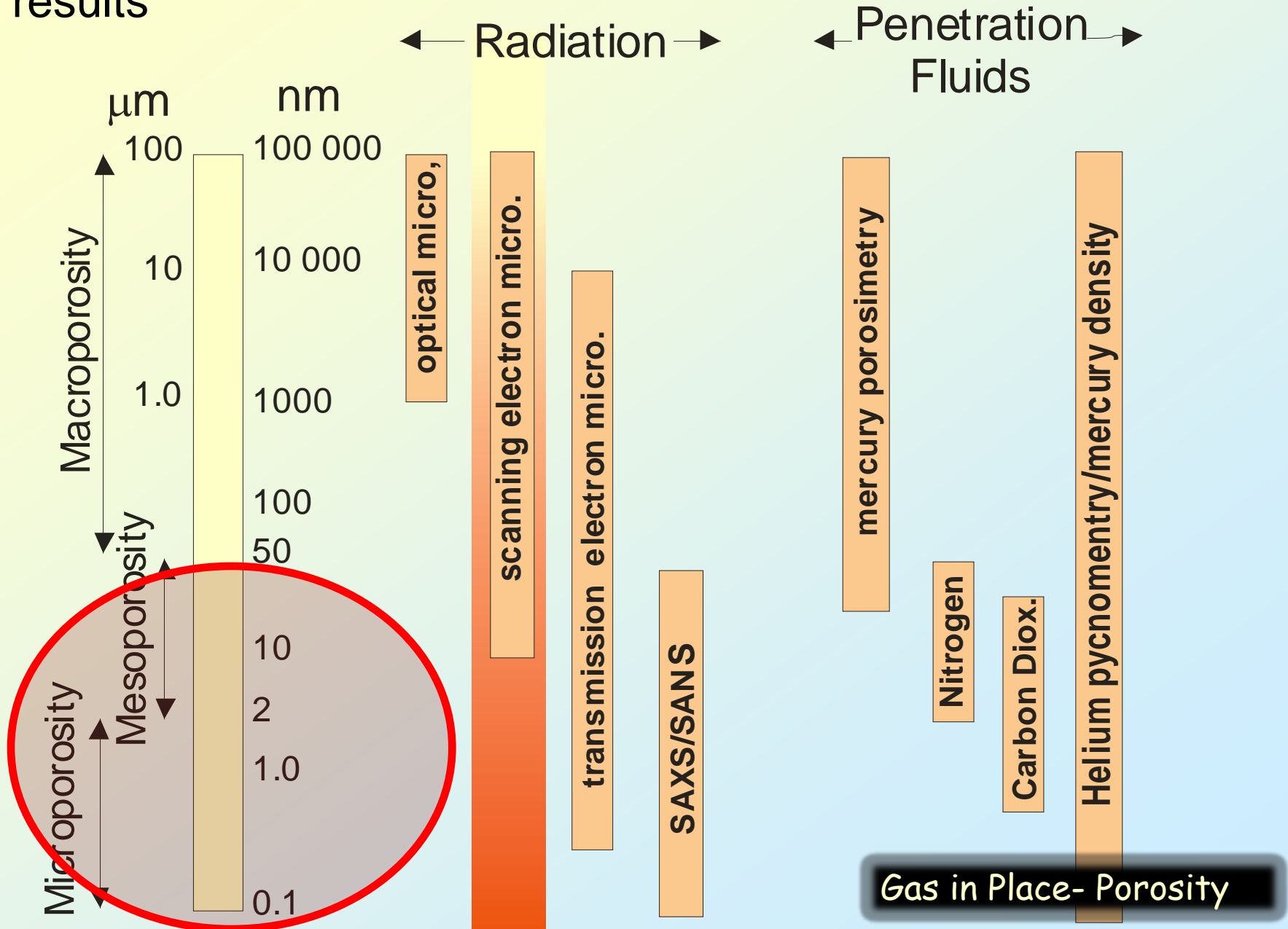
The pore/organic system in fine-grained rocks

FESEM

S4700 2.0kV 5.2mm x35.0k SE(U) 2/9/06   1.00um

pore
free
sorbed

ratio of free/adsorbed

100000
10000
1000
100
10
1
0.1
0.01
0.001
0.0001
0.00001

1.0E-11   1.0E-10   1 nm   1.0E-08   1.0E-07   1 µm   1.0E-05   1.0E-04   1.0E-03   1.0E-02

"Normal" porosity

pore diametre (m)

Methane molecule 0.38 nm

Modified from Beliveau, 1993
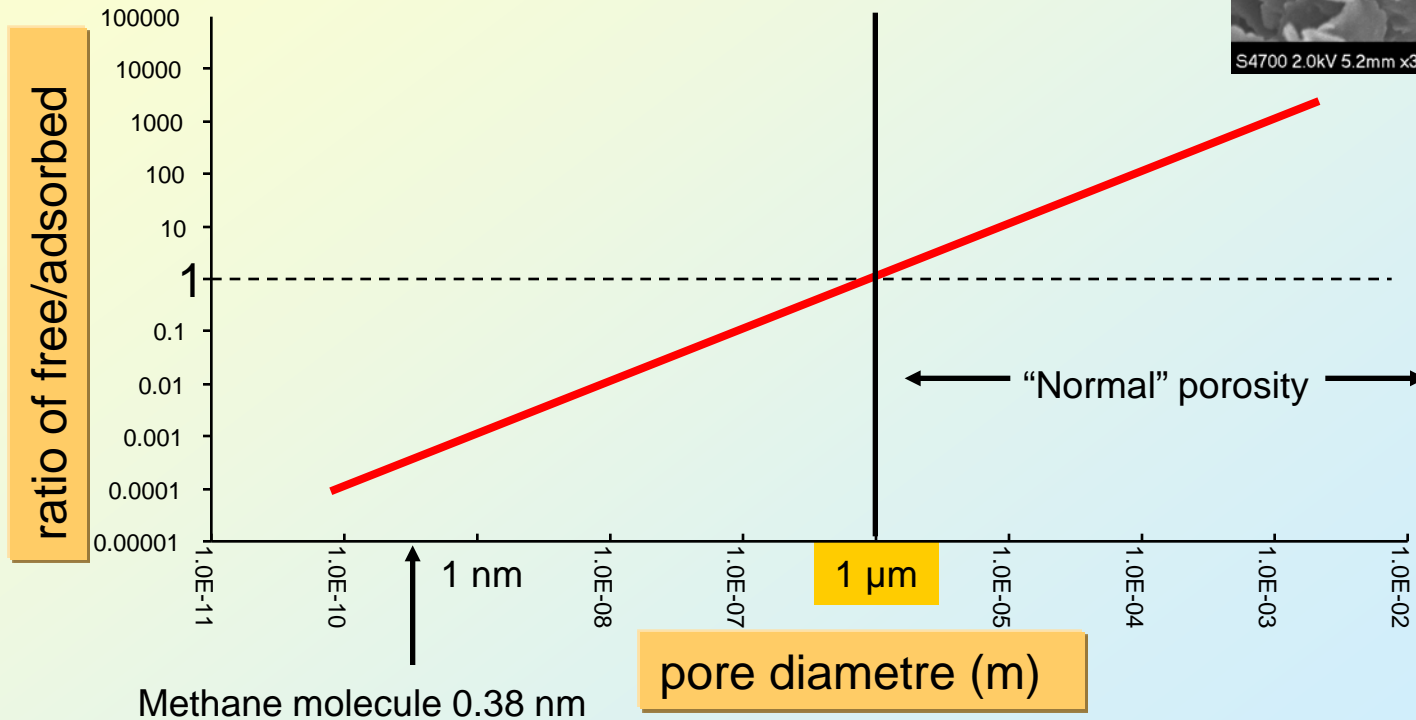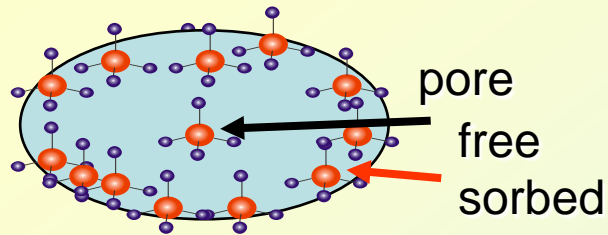
How you investigate microporosity determines the results

Radiation →

Penetration Fluids →

μm
nm

100	100 000
10	10 000
1.0	1000
	100
	50
	10
	2
	1.0
	0.1

Macroporosity

Mesoporosity

Microporosity

optical micro,

scanning electron micro.

transmission electron micro.

SAXS/SANS

mercury porosimetry

Nitrogen

Carbon Diox.

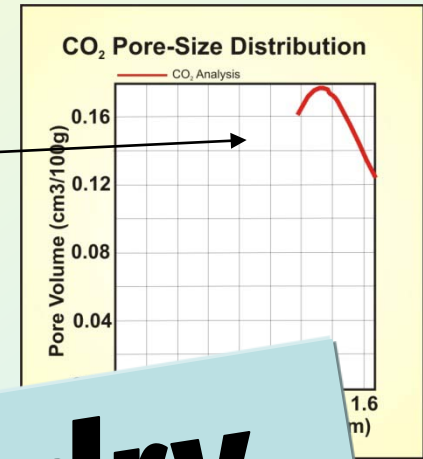Helium pycnomentry/mercury density

Gas in Place- Porosity

Pore Structure Analyses

- **Microporosity:**
  - **CO_2 low pressure isotherm analysis (D-R method)**

- **Meso-macroporosity:**
  - **N_2 low pressure isotherm analysis (BET theory)**
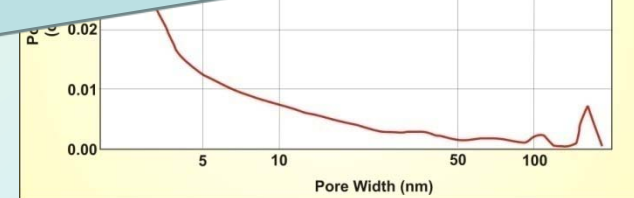 - **Hg porosimetry**

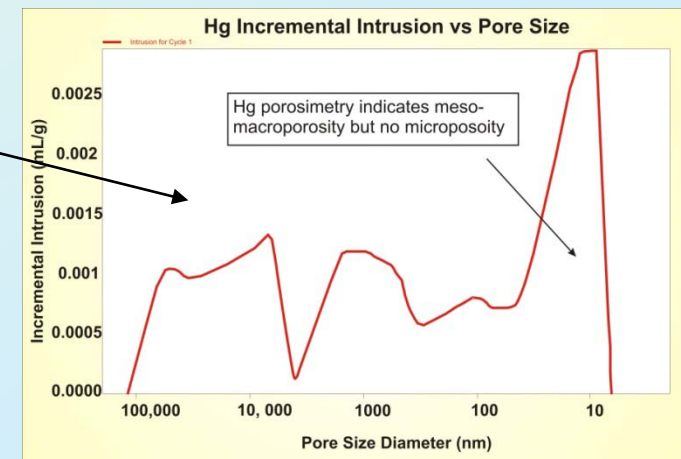- **Open Porosity**
  - **He pycnometry**
  - **Hg immersion**

CO₂ Pore-Size Distribution

N₂ Pore-Size Distribution

N₂ analysis reveals meso- and partial microporosity of the kerogen

Hg Incremental Intrusion vs Pore Size

Hg porosimetry indicates meso-macroporosity but no microposity

Pore Structure Analyses

CO₂ Pore-Size Distribution
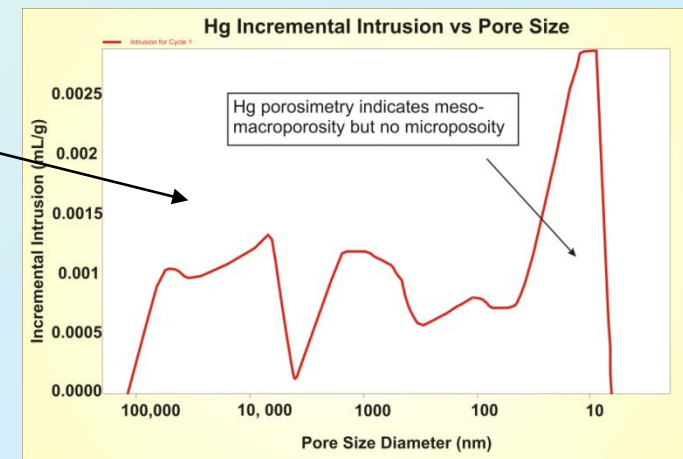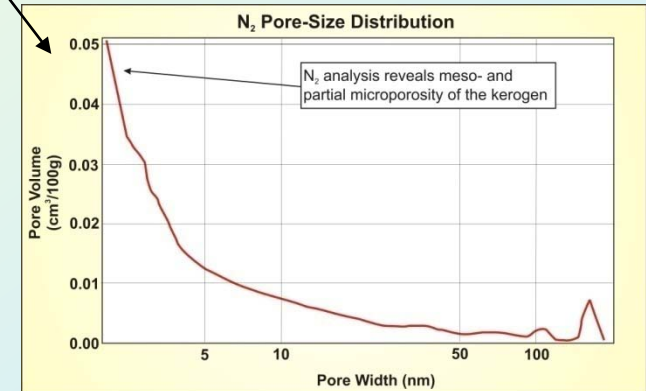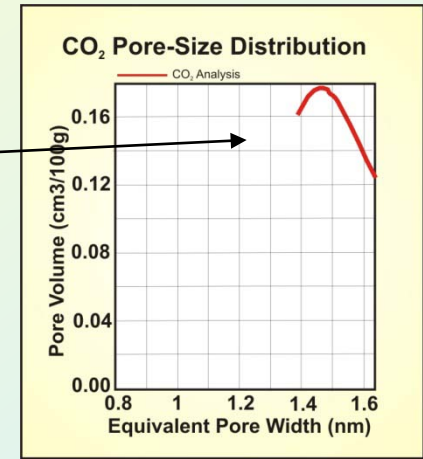
- **Microporosity:**
  - **CO₂ low pressure isotherm analysis (D-R method)**

samples must be dry

  - **(... theory)**
  - **Hg porosimetry**

- **Open Porosity**
  - **He pycnometry**
  - **Hg immersion**

Hg Incremental Intrusion vs Pore Size

Hg porosimetry indicates meso-macroporosity but no microposity

Incremental Intrusion vs Pore size

Dubinin-Astakhov Differential Pore Volume Plot (Exponent = 1.7078)

Pore Volume (cm²/g·Å)

Equivalent Pore Width (Å)

Pore size Radius (nm)
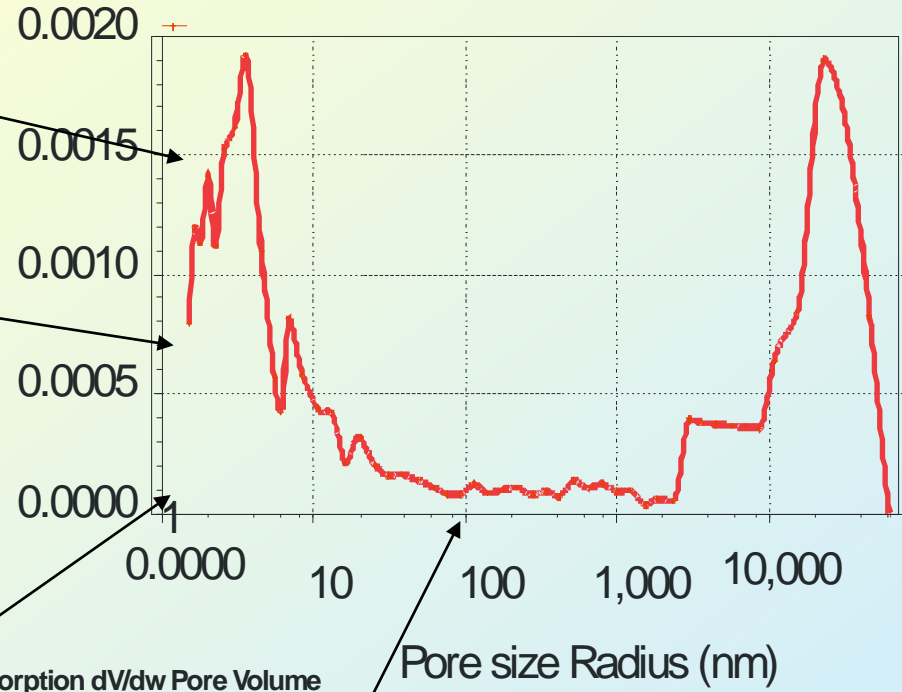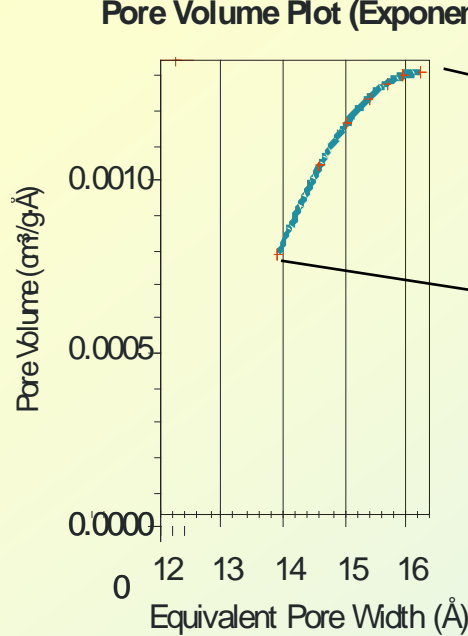
BJH Adsorption dV/dw Pore Volume
Faas Correction

Pore Width (Å)
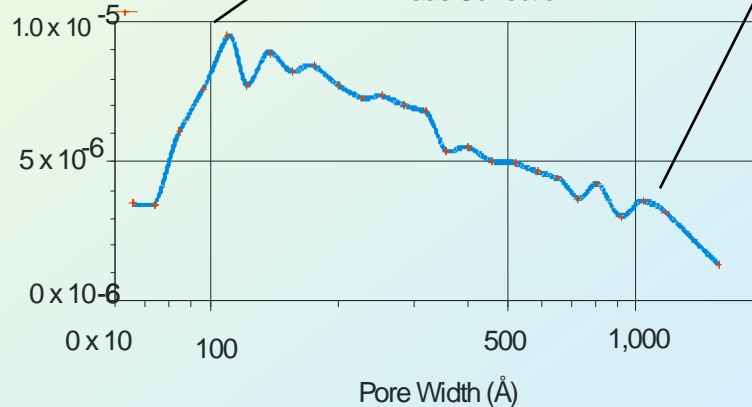
**Woodford Shale
4.92%**

CBM Solutions
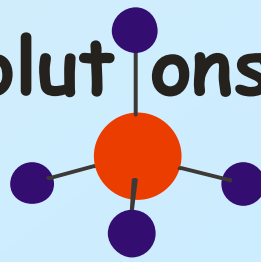
Implications of Pore Size Distribution- Sorbed Gas

- GIP- many companies measure using canister desorption as for CBM

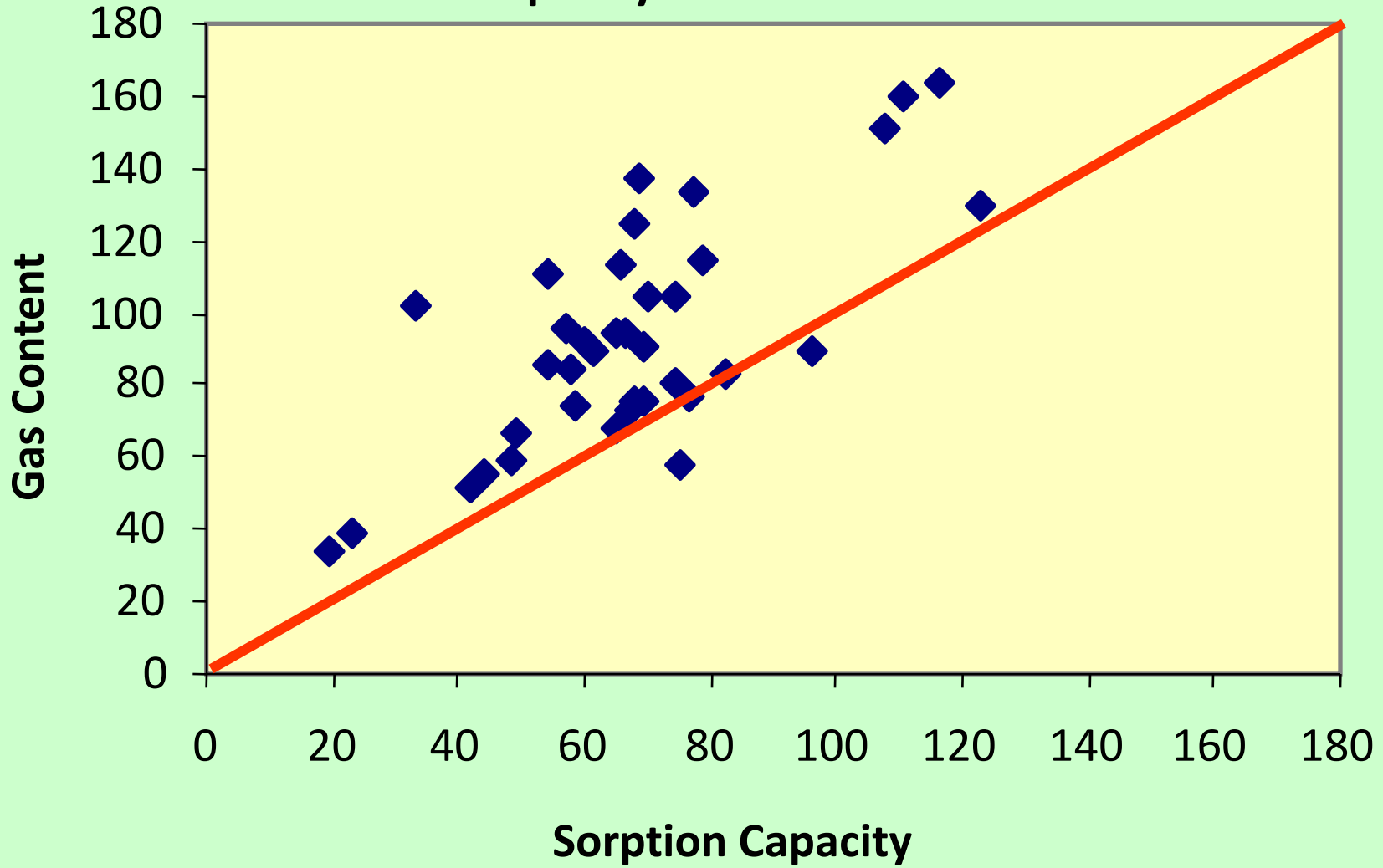- Desorbed gas is considered to be gas that was in the adsorbed state in the reservoir– **but is it?**

  remember:

OGIP = Free Gas + Adsorbed Gas+ Solution Gas

Desorption test indicates more gas than sorpton capacity

the problem

Desorbed Gas Content from canisters > Sorbed Gas Capacity
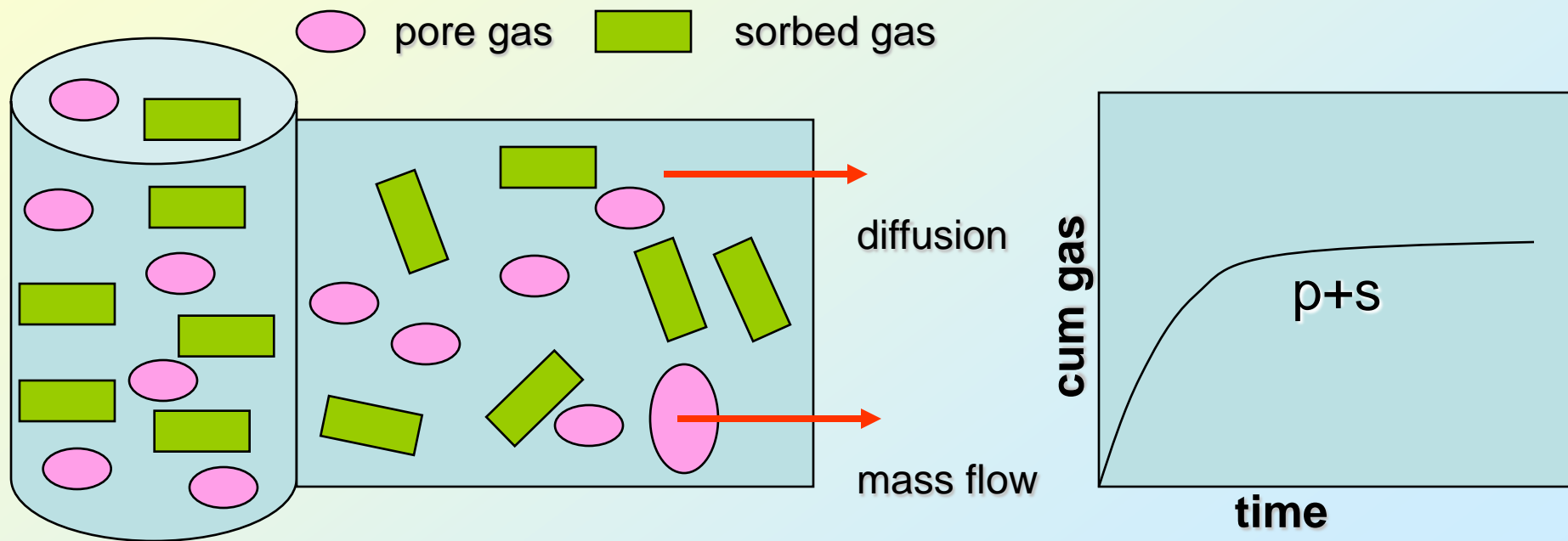
Gas Content

Sorption Capacity

Barnett- one of many examples
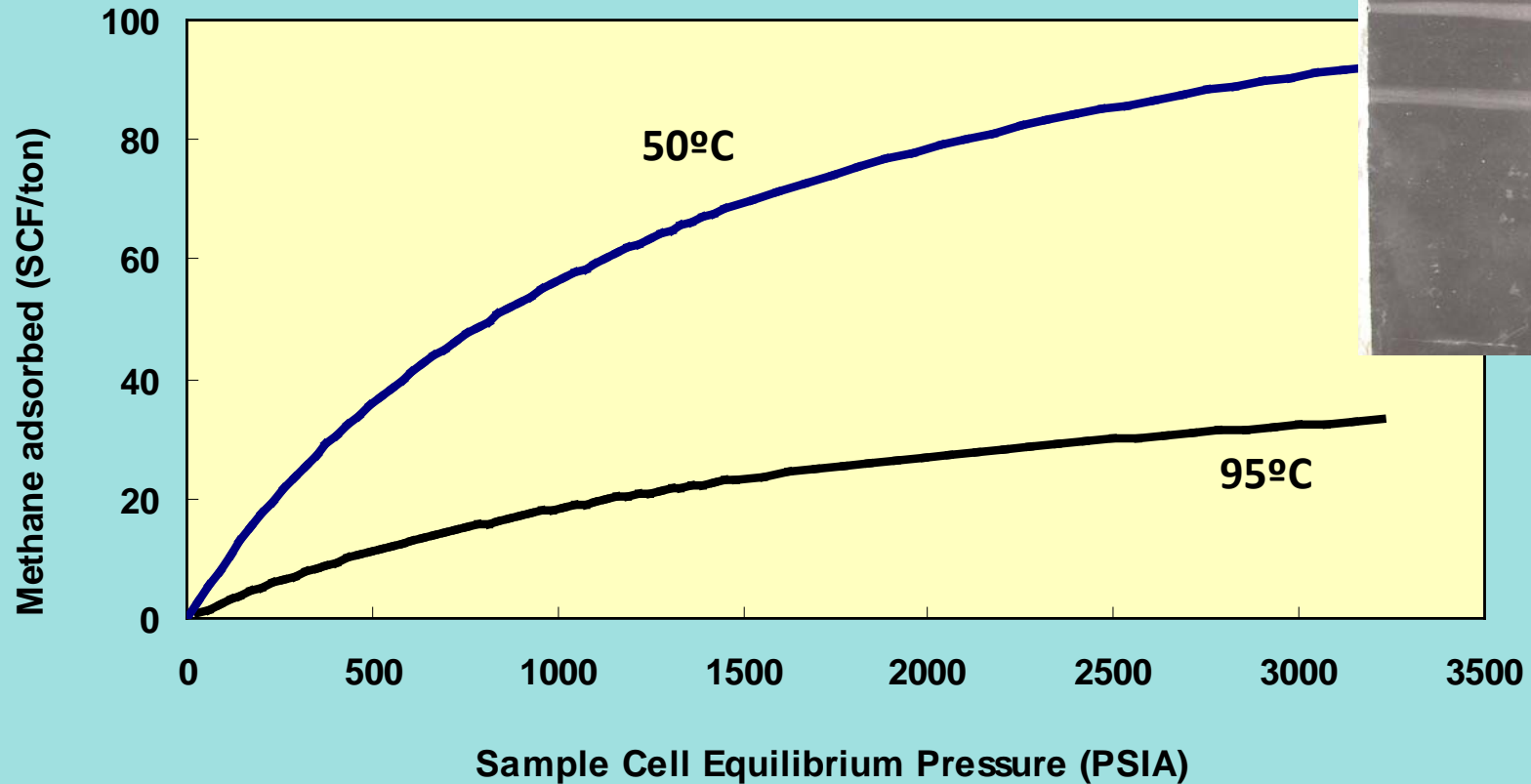
problem can be investigated in two ways

- numerically
- experimentally

numerical considerations: diffusion plus darcy flow of gas out of core

pore gas   sorbed gas

diffusion

mass flow

cum gas

p+s

time

relative contribution of diffusion and darcy flow depends on K, P and other factors
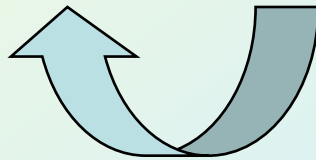
Barnett Composite

At high temperatures sorbed gas is not a major component of any gas shale

what does it mean

- if is assumed that desorbed gas = adsorbed gas

- free gas obtained from Sw and Porosity

total gas = desorbed + ø×(1-Sw) + solution

total gas is overestimated (i.e., double dipping the free gas)

Quantifying porosity and Sw

- well logs yield poor data in argillaceous strata- need lab measurements to calibrate logs

- commercial lab measures grain and/or skeletal density with He and Hg bulk density with Hg- **after** drying the sample

- sorbed gas occupies space

- what about pore compressibility!

V= -

He   **Hg**

$$\Phi = 1 - (V_b/V_p)$$
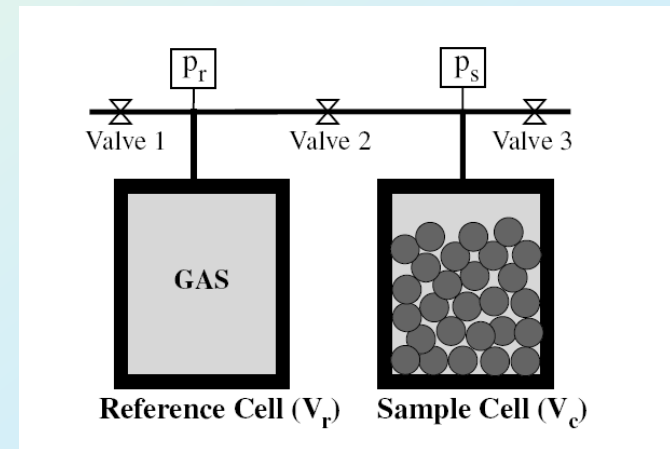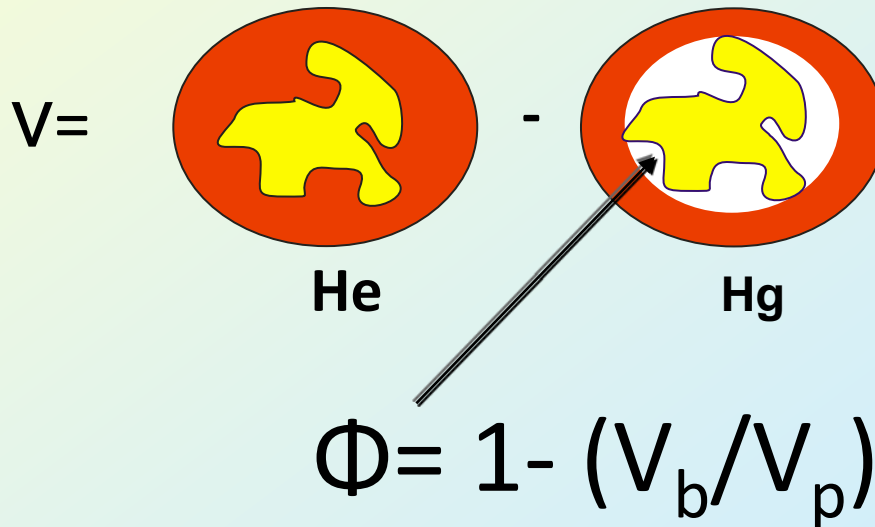
Molecule	Crtical Diameter (nanometres)
Helium	0.2
Carbon dioxide	0.28
Nitrogen	0.3
Water	0.32
Methane	0.4
Ethane	0.44
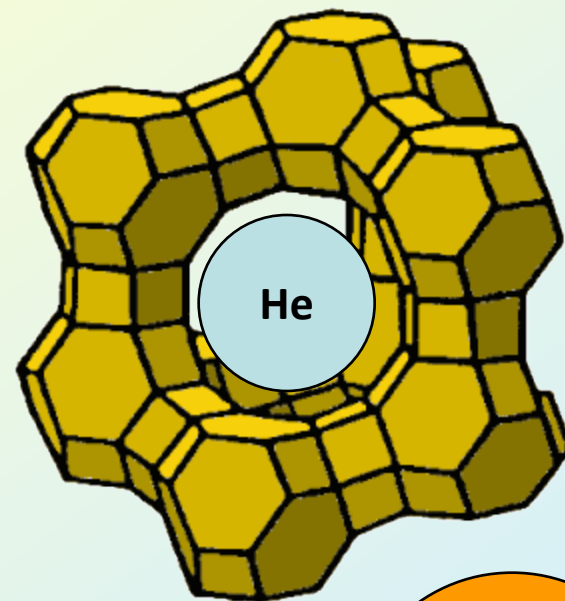
pore access varies with kinetic diameter

Bustin and Ross, 2006
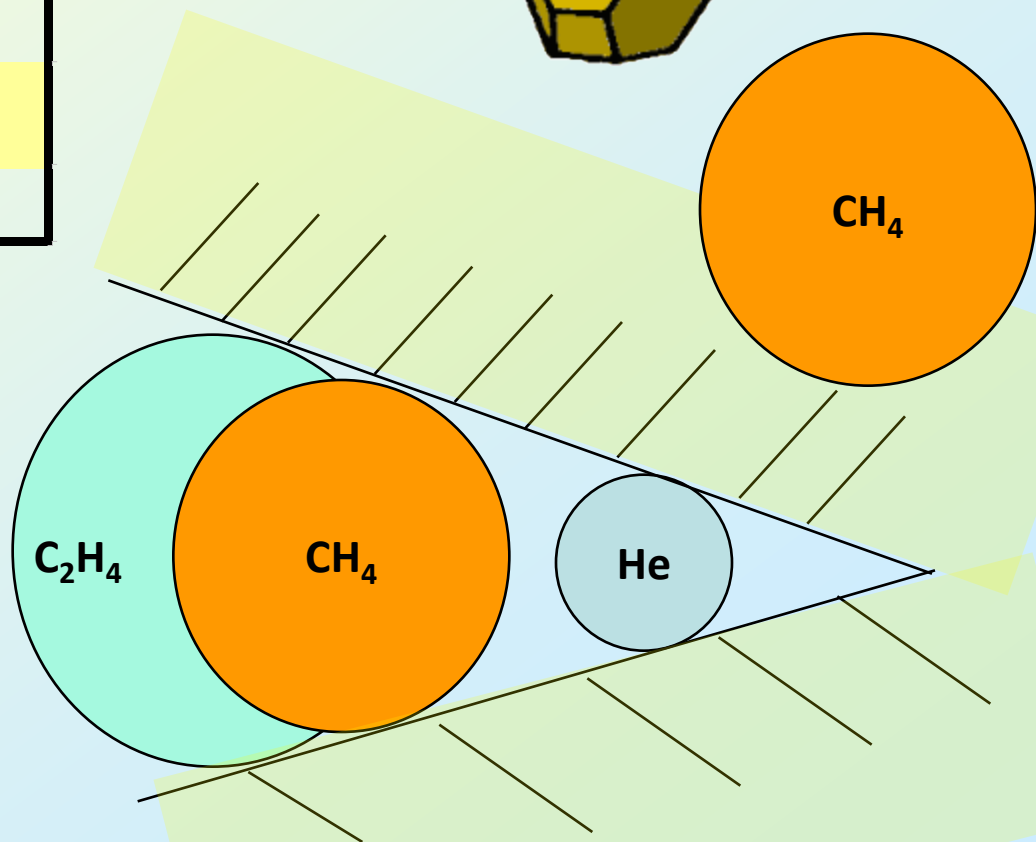
porosity varies with gas used to measure it and pore size distribution of shale

Variation in Density with Gas
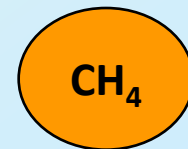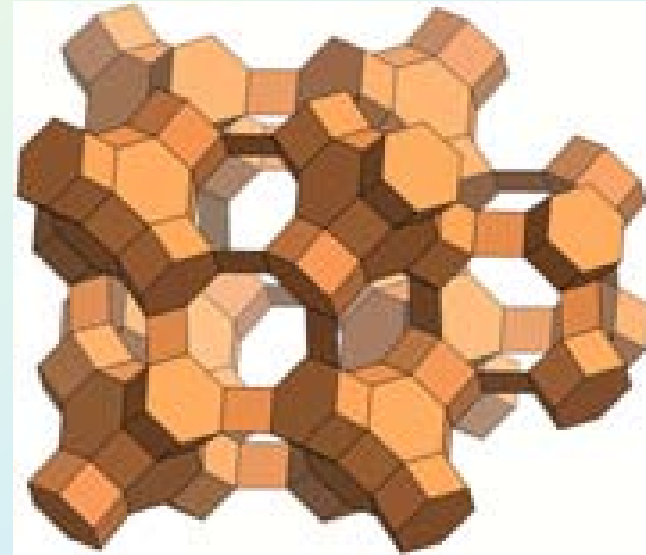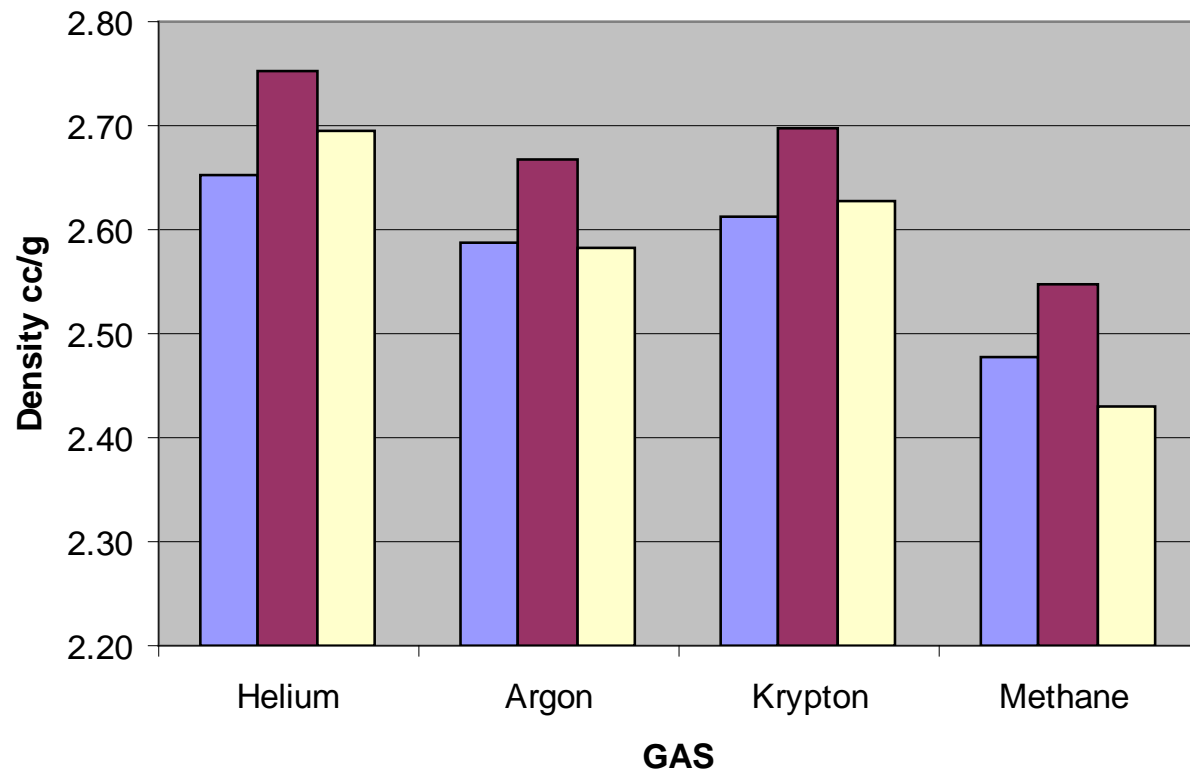
Density cc/g vs GAS (Helium, Argon, Krypton, Methane)

CH$_4$

is the solution to use a larger gas molecule (i.e., Methane, Argon or Krypton)??
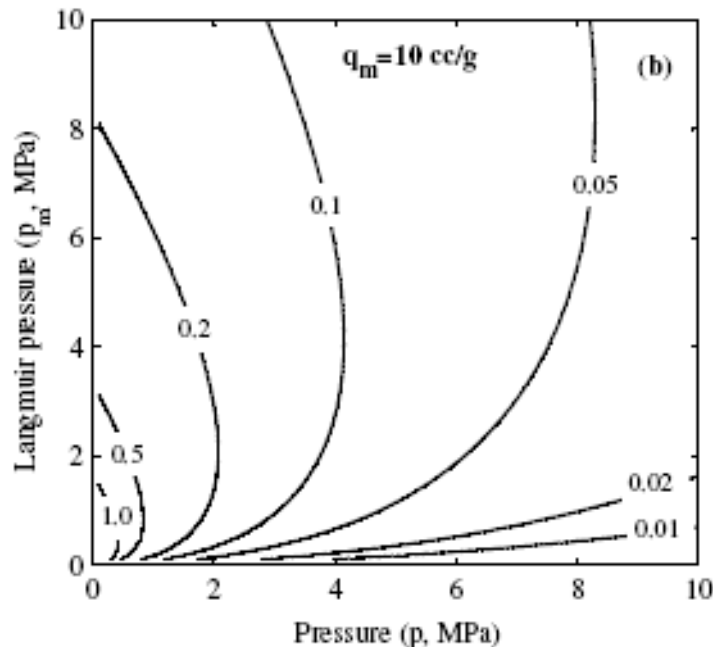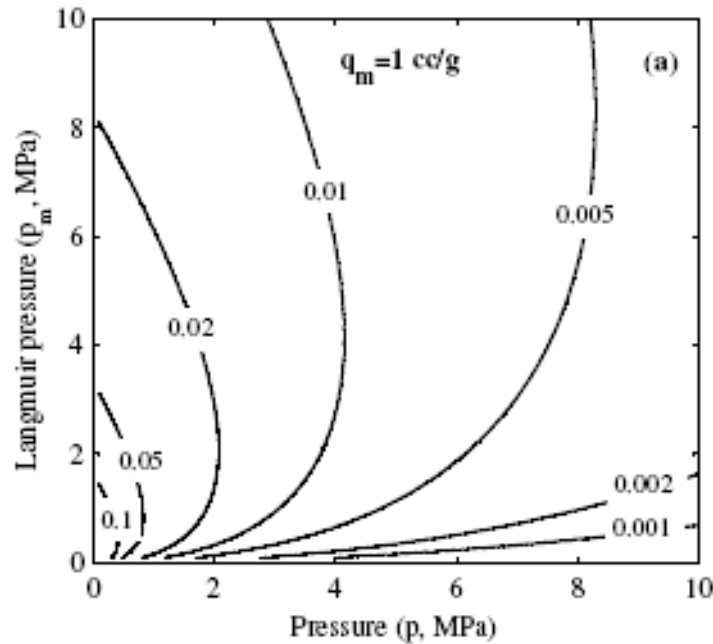
- all gases sorb (even He)

(we quantify gas in experiment by correcting for Z)

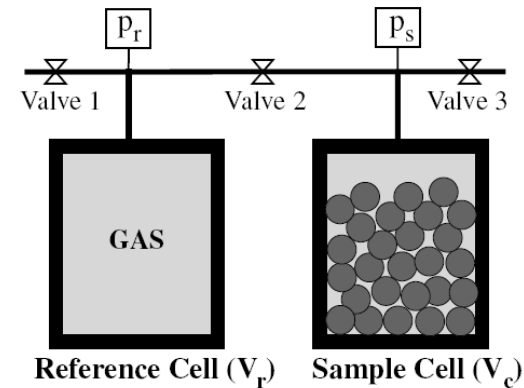if sorption takes place during the experiment

 = wrong answer

..... how wrong... depends on the sorption capacity of the rock (surface area) and gas in use.

change in effective porosity due to adsorption

$$\phi_a = Rt / xc \frac{1 \times 10^3 \rho_c}{V_{std}} \frac{(1-\phi)}{\beta\rho} \frac{q_L p_L}{(p_L + p)^2}$$

effective porosity due to gas sorpton

if some gas
is sorbed during
experiment the
= >ΔP

(modified from Cui and Bustin, in prep.)

and hence

- porosity measurements using skeletal density measured by He too high (always)

- with other gases correction for sorption is mandatory

- correction for pore compressiblity is a must
and

the error in porosity calculation also results in a humongous error in isotherm analyses where void volume is measured by He

Laboratory Permeability

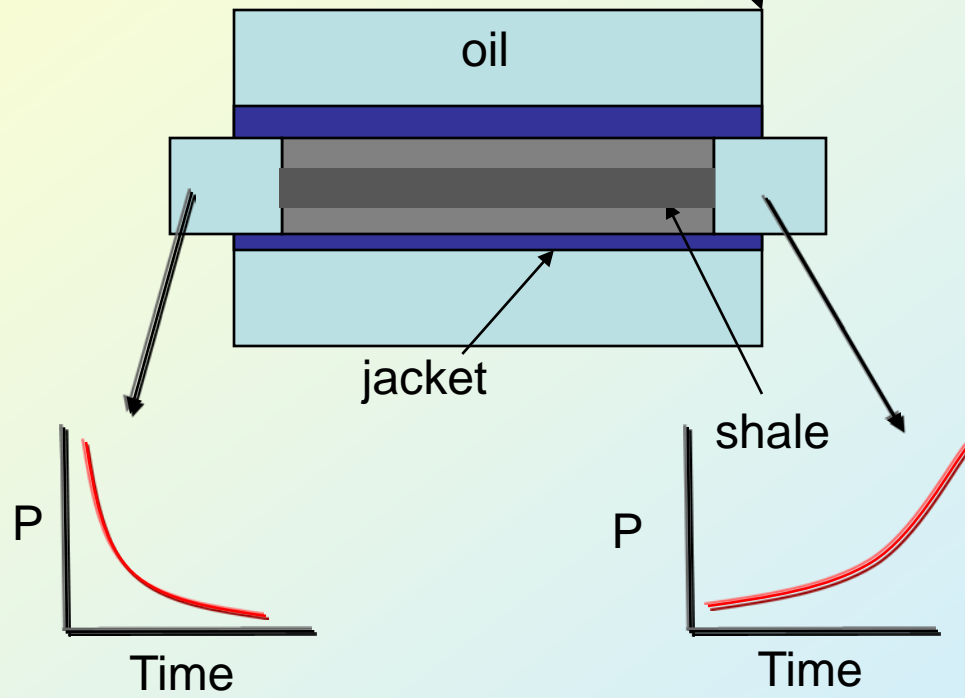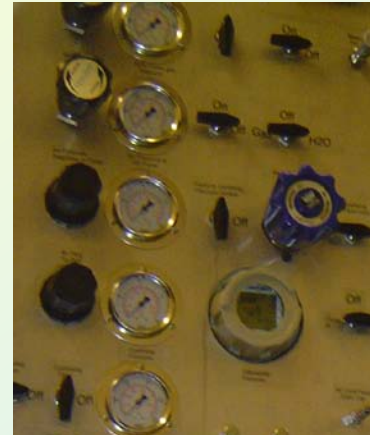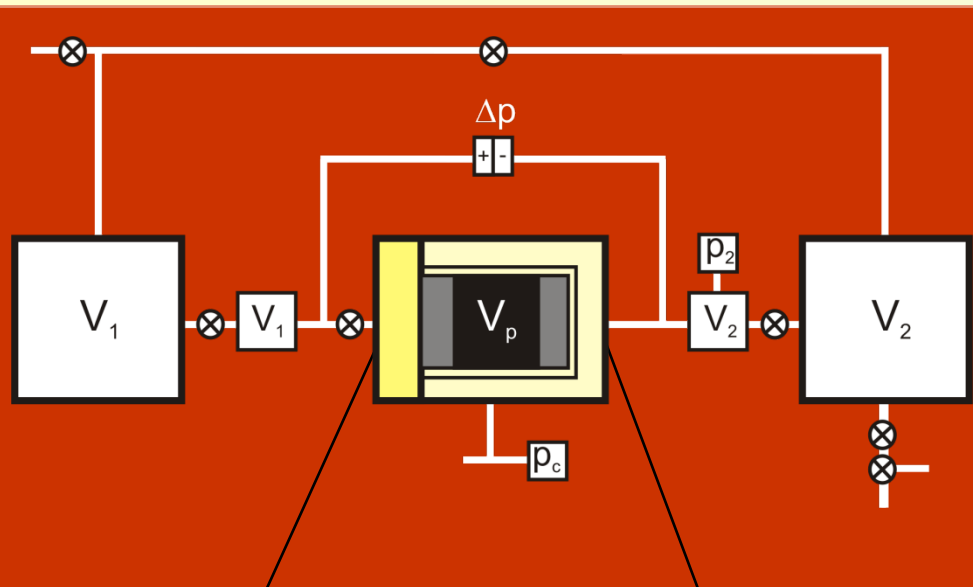-pulse decay on cores confined under reservoir conditions

Brace et al. (1968); Dicker, A.I., and R.M. Smits, 1988: Jones, S.C., 1997

-pulse decay on crushed samples (GRI, 1996; Egmann et al., 2005)

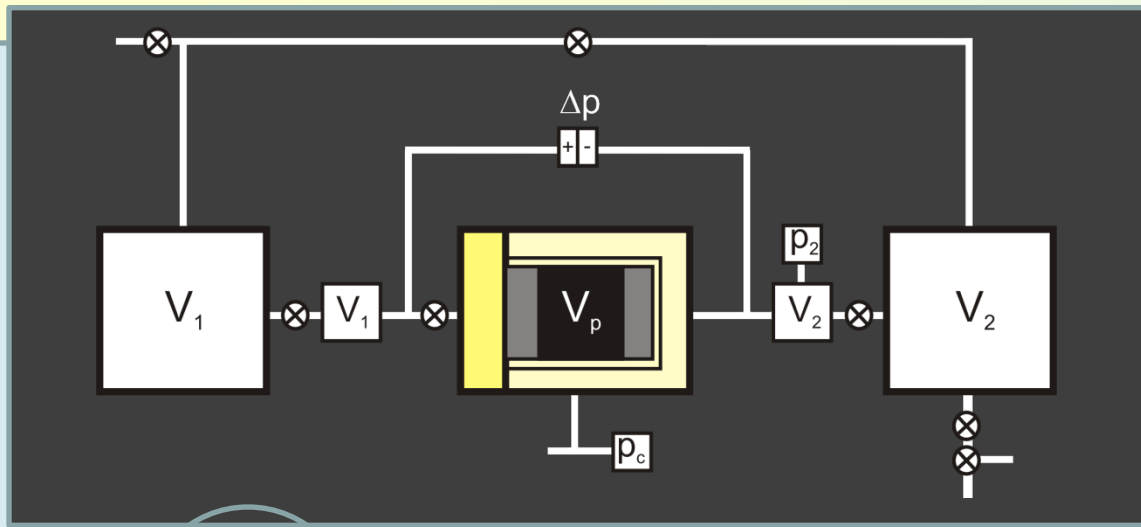-from 'desorption rates' (Cui and Bustin, in prep)

-from intrusion curves in Hg porosimetry (Swanson, 1981)

experimental setup

oil
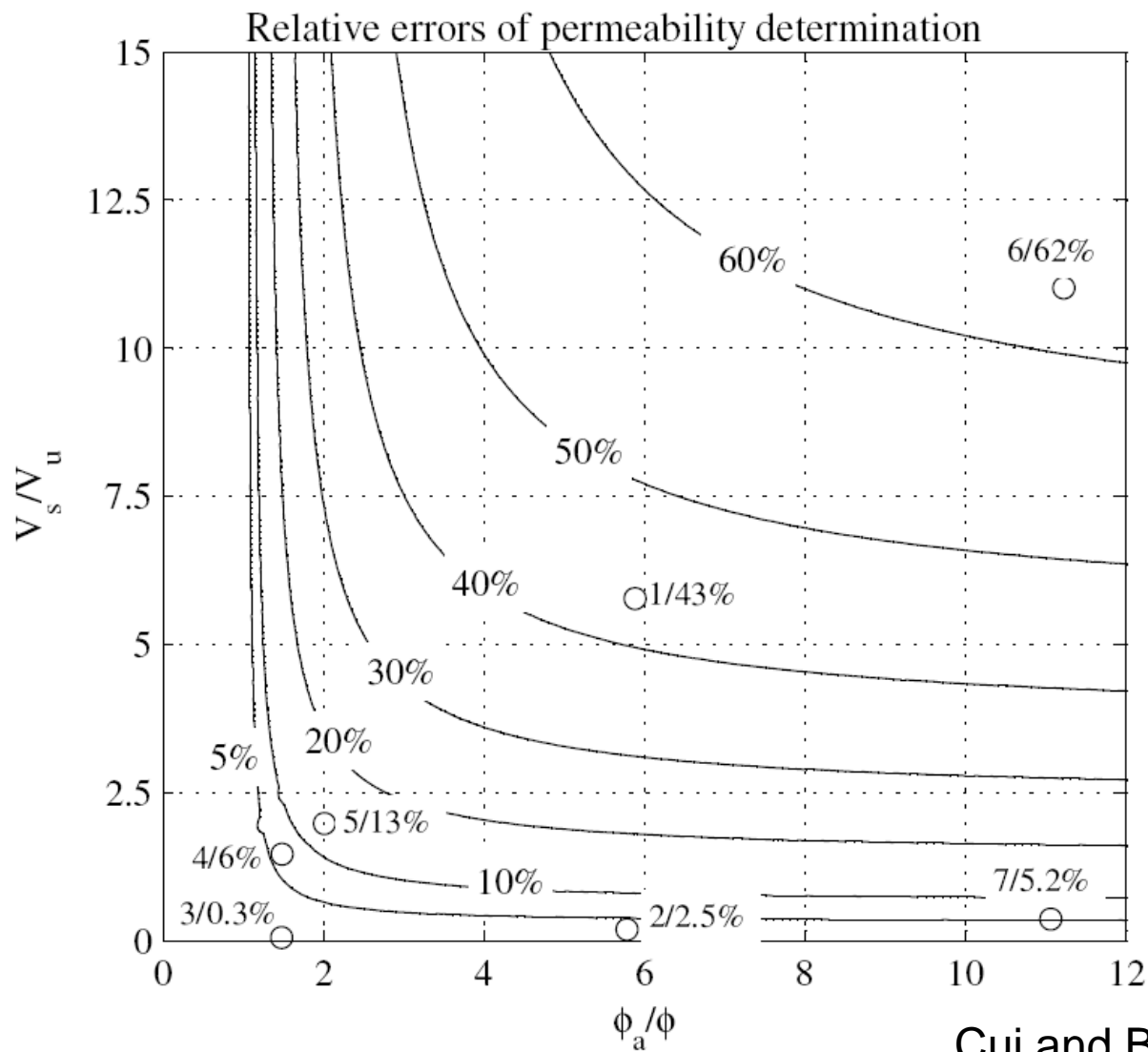
jacket

shale

P | Time

P | Time

deliverability

$$\kappa = \frac{R_a^2}{\alpha_1^2} \frac{[\phi + K_a] K_\rho \mu_m}{\rho_m} K_s$$

$$D = \frac{R_a^2}{\alpha_1^2} \frac{[\phi + K_a]}{\phi} K_s$$

$$K_a = \frac{1 \times 10^3 \rho_c}{V_{std}} \frac{q_L p_L}{(p_L + p)^2} K_\rho$$
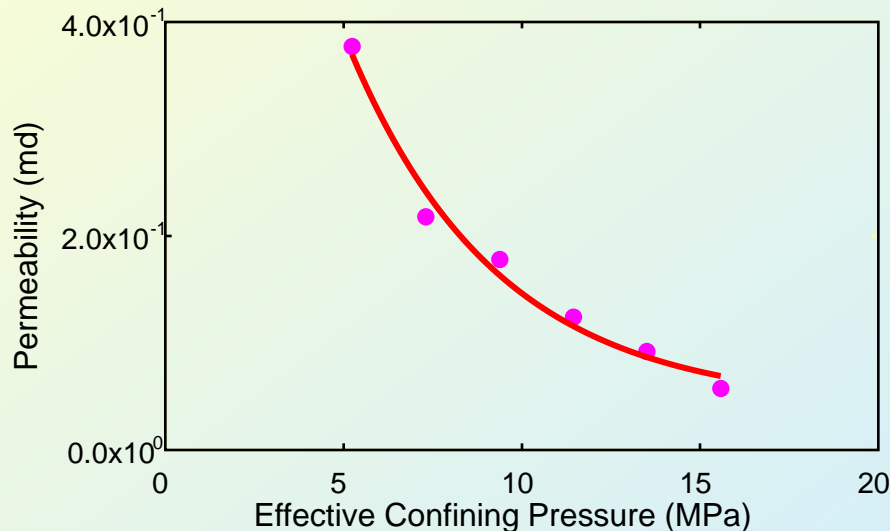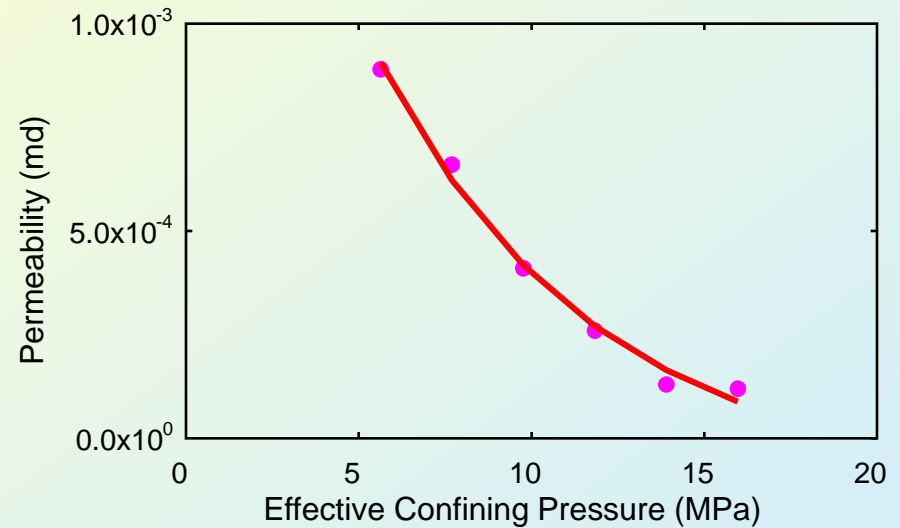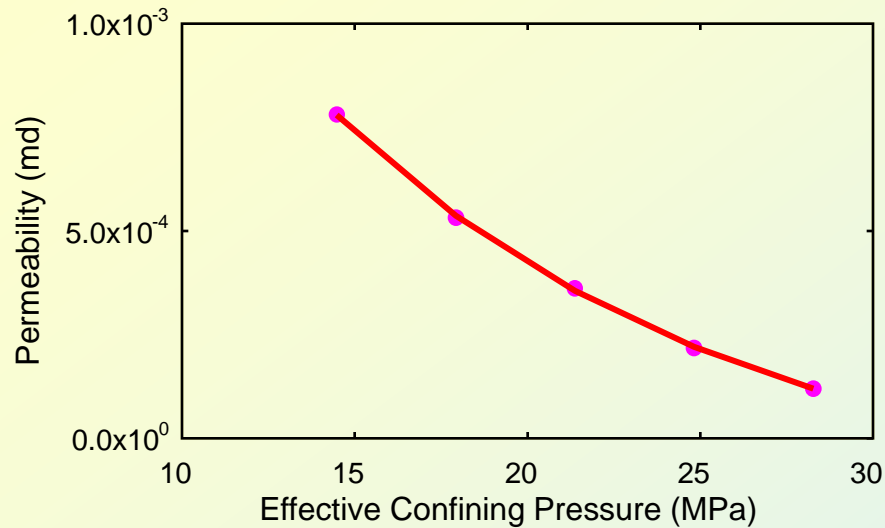
(Cui and Bustin, in prep)

Relative errors of permeability determination

Cui and Bustin, in prep.

ϕ = porosity
ϕ_a = effective porosity contributed by adsorption

Variation of k/Diffusion with Effective Stress
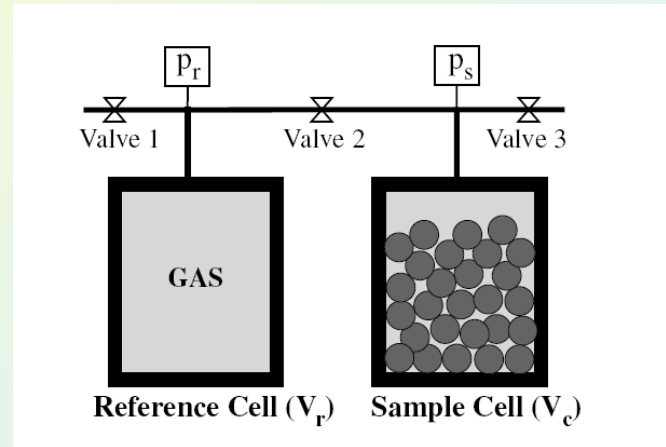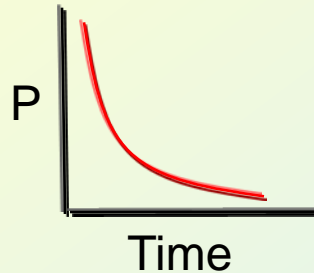

The ability of gas to be produced from shales decreases markedly with increase in effective stress and hence depth. Kvert <<< Khorz

Laboratory Permeability

-pulse decay on crushed samples (GRI, 1996; Egmann et al., 2005)

problems

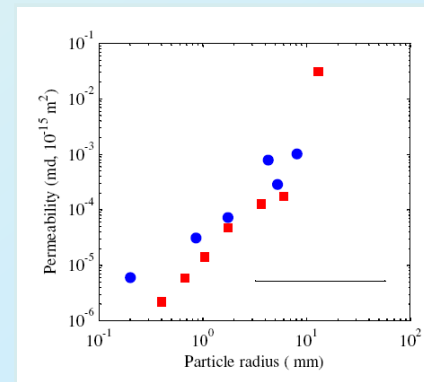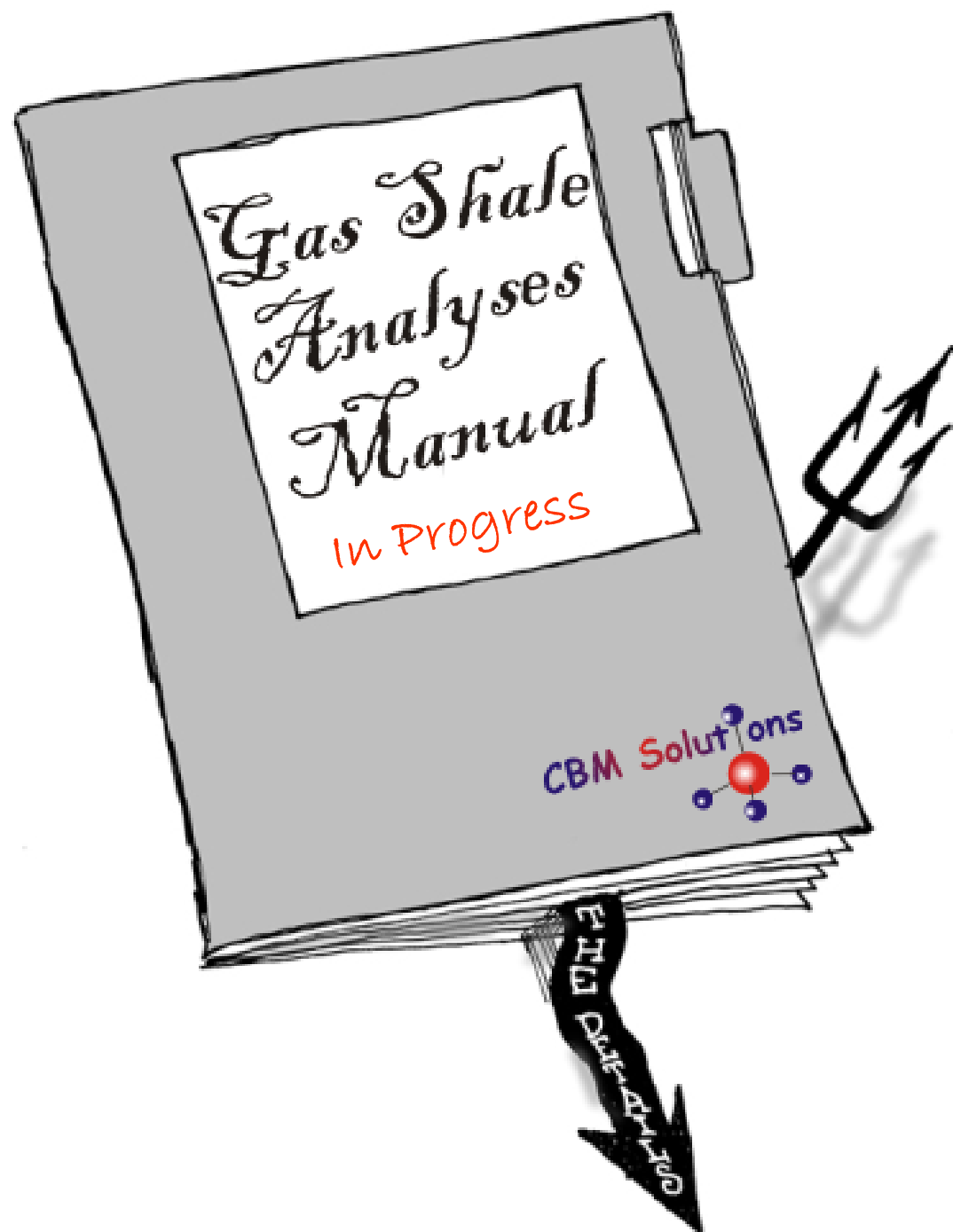-same issues as using core- must correct for sorption of gases
-analyses performed under hydrostatic conditions (i.e., no consideration
of pore compressibility)
- pore compressibility is rock specific (fabric and mineralogy)

advantages

easy/cheap
reproducible
but not the answer you want to put in your simulator

gas shales – tremendous resources but not for the faint of heart or the thin of wallet

Selected References

Beliveau, D., 1993, Honey, I shrunk the pores!, Journal of Canadian Petroleum Technology, v. 32/8, p. 15-17.

Brace, W.F., J.B. Walsh, and W.T. Frangos, 1968, Permeability of granite under high pressure: Journal of Geophysical Research, v. 73/6, p. 2225-2236.

Bustin, R.M., 2005, Comparative analyses of producing gas shales; rethinking methodologies of characterizing gas in place in gas shales: Bulletin West Texas Geological Society, v. 45/2, p. 9-10.

Dicker, A.I., and R.M. Smits, 1988, A practical approach for determining permeability from laboratory pressure-pulse decay measurements: SPE International Meeting on Petroleum Engineering, 1-4 November 1988, Tianjin, China, SPE Paper 17578.

Hamblin, A.P., 2006, The "shale gas" concept in Canada: a preliminary inventory of possibilities: Geological Survey of Canada, Open File Report 5384, 108 p.

Ross, D.J., and R.M. Bustin, 2006, Sediment geochemistry of the lower Jurassic Gordondale member, Northeastern British Columbia: Bulletin of Canadian Petroleum Geology, v. 54/4, p. 337-365.

Swanson, P.L., 2001, Subcritical crack propagation in westerly granite; an investigation into the double torsion method: International Journal of Rock Mechanics and Mining Sciences, v. 18/5, p. 445-449.