Hydrocarbon Migration and Accumulation Models Revisited from a Reservoir Engineering Perspective*

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Abstract

Conventional petroleum migration and hydrocarbon accumulation has been investigated in the laboratory and field, principally by considering the interaction between the capillary and buoyancy force within carrier beds and under seals. The best oil migration pathways are generally believed to be the highly porous and permeable beds within a petroleum system. The best seals are considered to be the low permeable rocks. Oil migration and accumulation in rock formations of low porosity and permeability (e.g. tight sandstone) would require an unusually large driving force or oil column height and is thus rarely considered. Apart from the pore-throat size, oil-water interfacial tension and reservoir wettability can also play important roles in controlling the capillary force. The latter two parameters are often not considered. In reality, oil migration pathways and seals may have a range of wettabilities, from strongly water-wet through mixed-wet to strongly oil-wet. The reservoir fluid compositions and properties (e.g. viscosity, density and interfacial tension) are dynamic (varying with P/T) and change within a petroleum system.

We investigated the hydrocarbon migration and accumulation mechanisms using a petroleum engineering approach by evaluating various factors affecting hydrocarbon migration and accumulation using glass bead columns, rock and fluid characterization techniques under subsurface conditions and core flooding experiments. The key parameters investigated include: (1) viscosity changes, (2) wettability alteration, and (3) interfacial tension variations with P/T conditions. Other petroleum engineering aspects examined include (1) relative permeability, (2) imbibitions, (3) Capillary Numbers, and (5) mobility ratios. The experiments have shown that these factors can significantly affect hydrocarbon migration and accumulation. For example, oil was found preferably migrating through and/or accumulating in relatively tight regions with a favorable wettability. Therefore these petroleum engineering factors should be included in the conventional petroleum migration and accumulation models, especially when investigating the unconventional petroleum system (e.g. tight sandstone oil).

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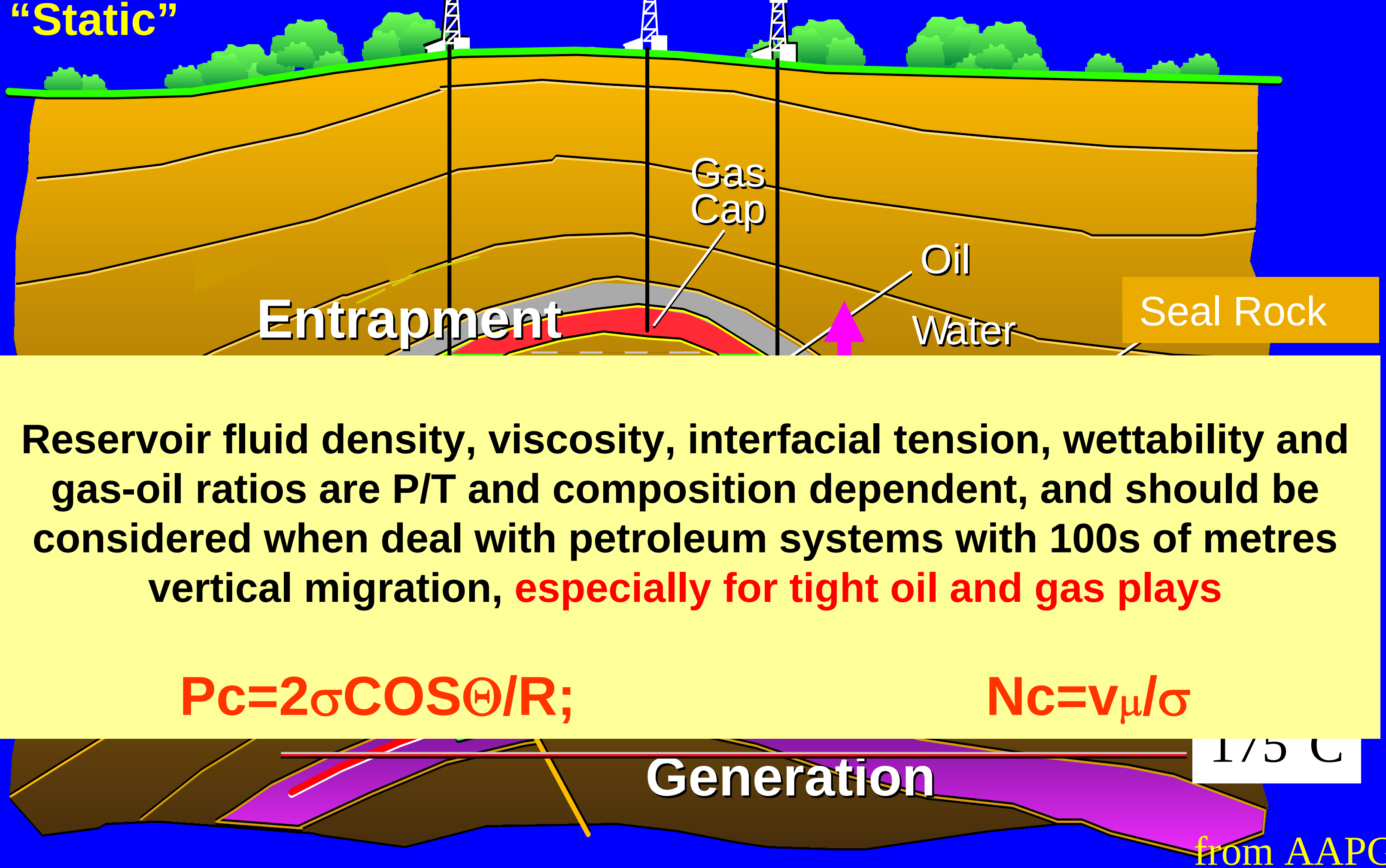
Existing Oil Migration & Accumulation Model

- **Permeability and porosity controlled only (Pc [r] vs Pb)**
- **“Static”**



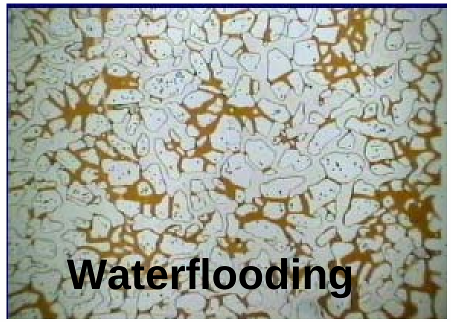
Reservoir fluid density, viscosity, interfacial tension, wettability and gas-oil ratios are P/T and composition dependent, and should be considered when deal with petroleum systems with 100s of metres vertical migration, especially for tight oil and gas plays

$$Pc=2\sigma COS\Theta/R; \qquad Nc=v\mu/\sigma$$

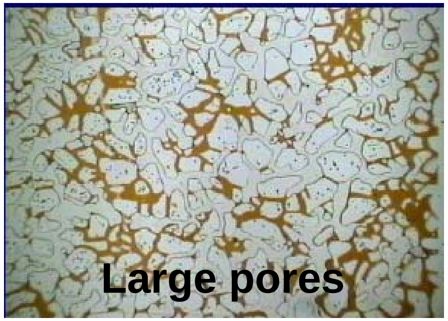
Presentation Outline

- **Factors affecting hydrocarbon migration & accumulation**
  - Rocks
  - Fluids
  - Fluid-fluid and fluid-rock interaction
- **Secondary Migration Laboratory Experiments**
  - Glass bead experiments
  - Core flooding experiments
- **Field application examples**
  - Tight oil and gas reservoirs in the Tarim Basin
  - Basin floor lenticular reservoirs in the Bohai Bay Basin
- **Summary**

Oil accumulation process vs (enhanced) oil recovery

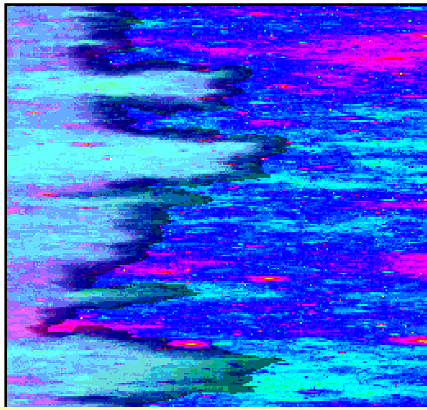


Oil accumulation processes are the inverse of that of the oil recovery



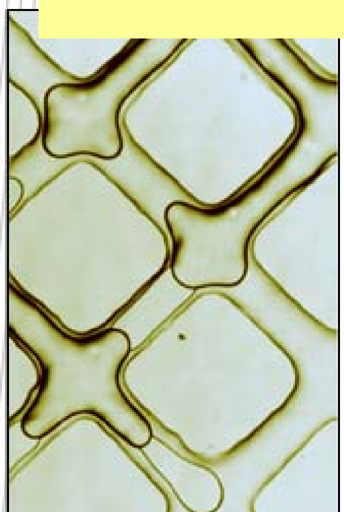
$$Pc=2\sigma COS\Theta/R; \quad Nc=v\mu/\sigma$$

Petroleum engineering approach to investigate oil migration & accumulation



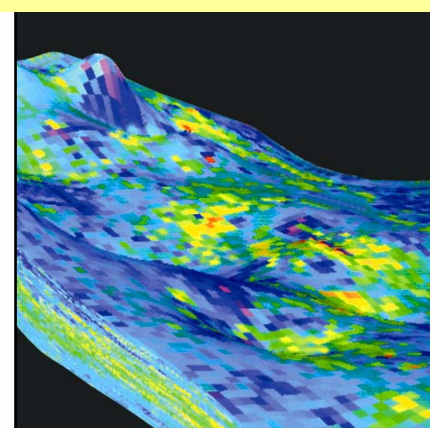
Core flooding experiment: Physical simulation and numerical modelling

Petroleum engineering approach can be used to investigate HC accumulation



Pore scale

Reservoir scale



Reservoir compositional heterogeneities at pore scale: the Rock factor

Apart from

Φ/K factors,

different

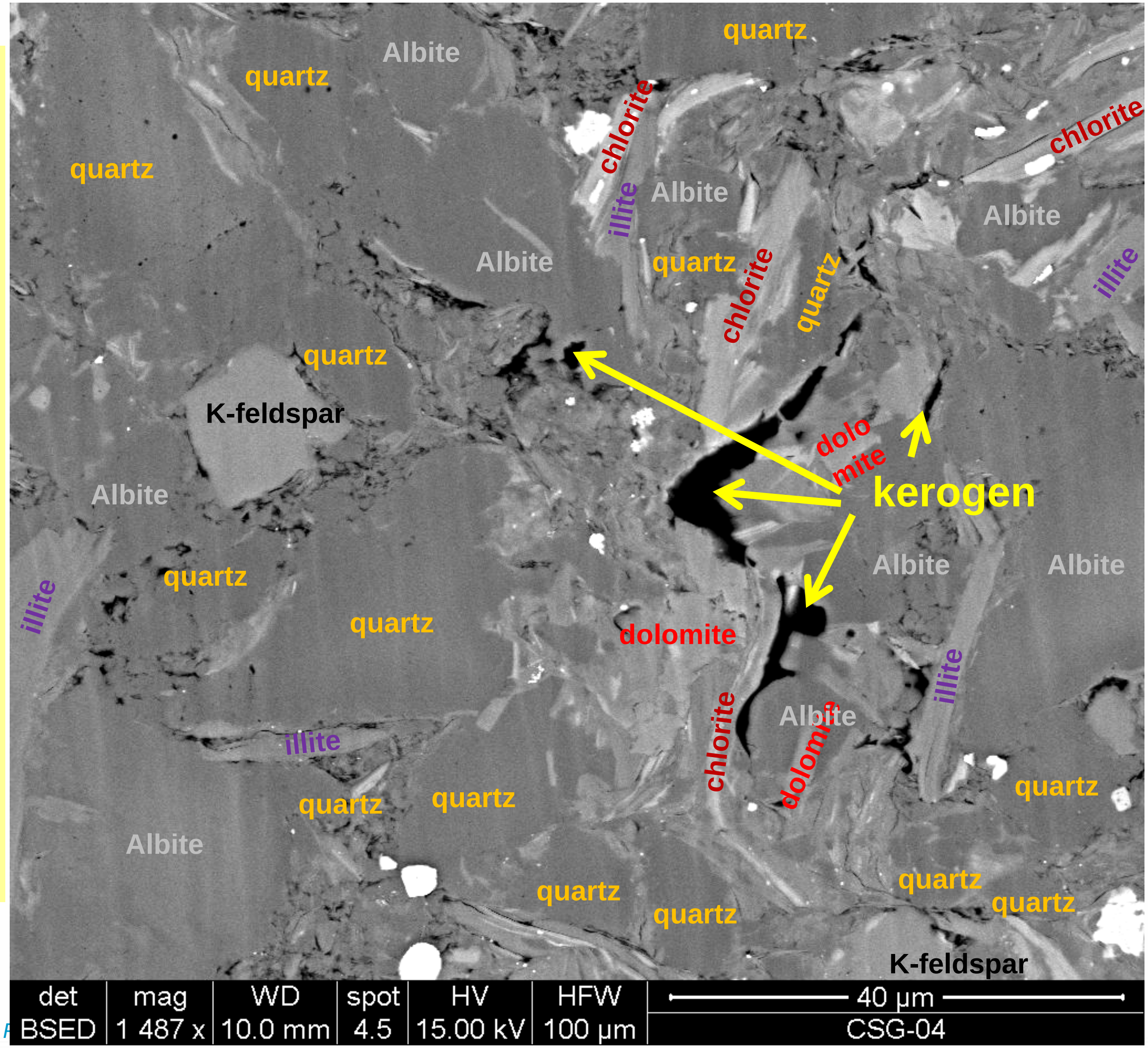
minerals have

different

affinities to

reservoir

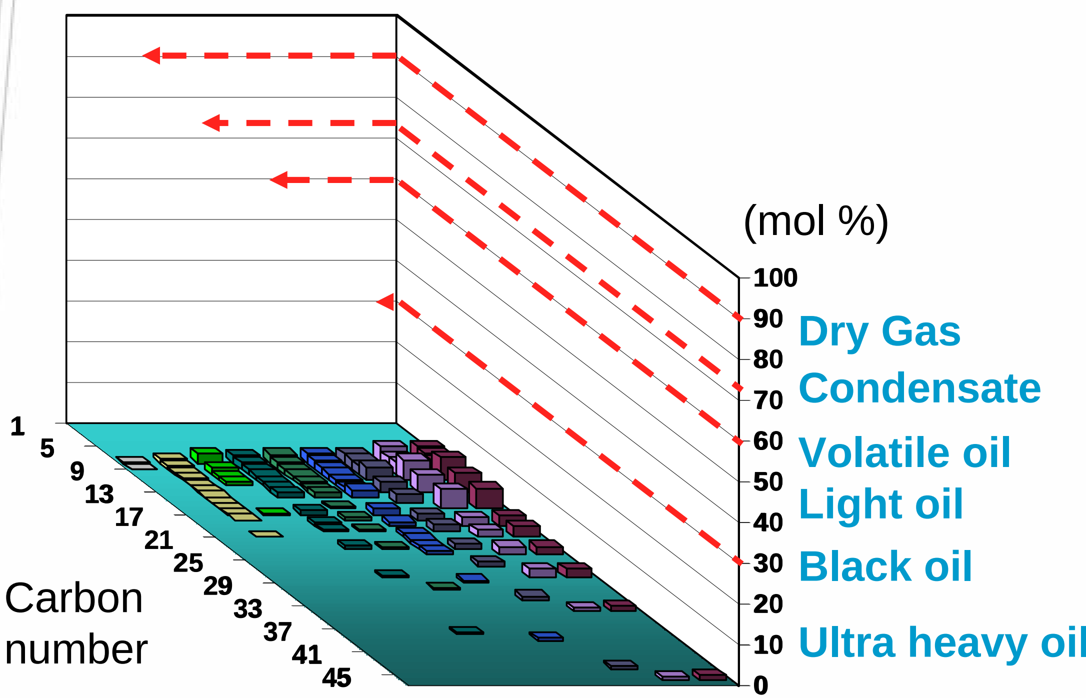
fluids



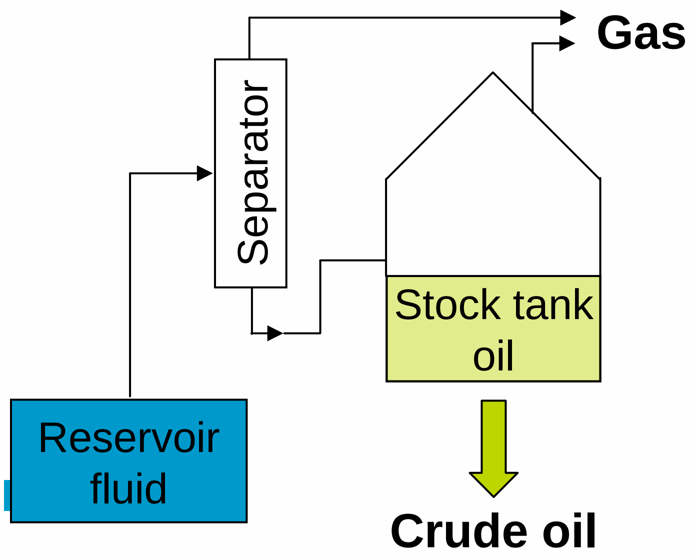
Subsurface reservoir oil vs surface (dead) crude oil : the fluid factor

Dead oil at surface conditions

Classical petroleum reservoir fluids



Multicomponent mixture consisting primarily of methane (>30-90 mol%)

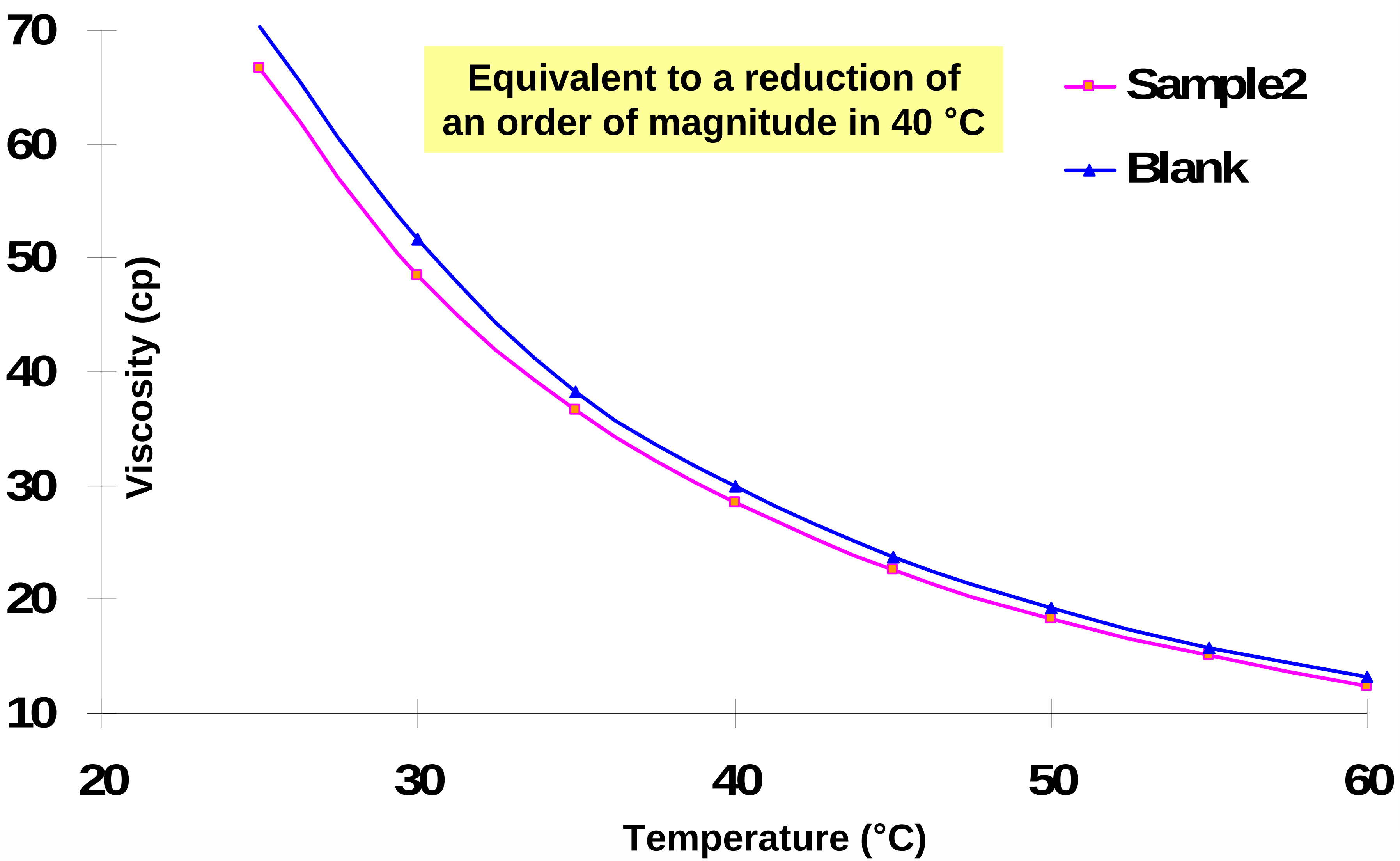


+ inorganic gas

CO_2, H_2S, N_2, SO_2, H_2…

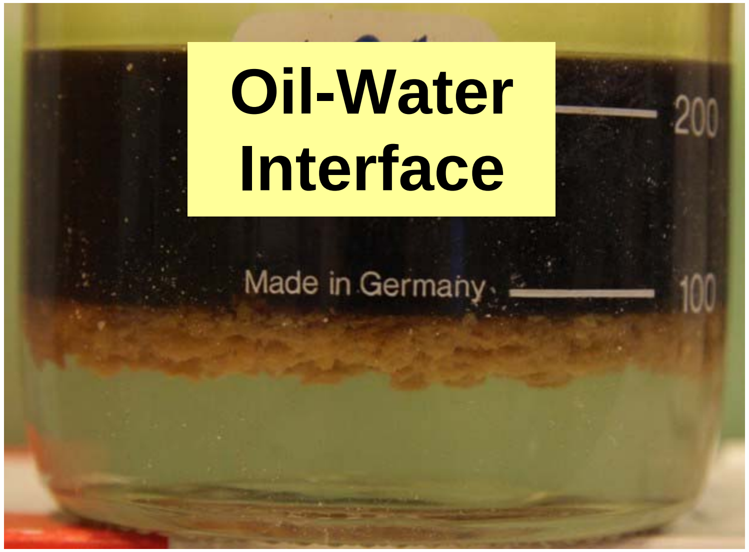
$$^{o}\mathbf{API} = \left(141.5 \times \frac{\text{Density of water at } 15^{o}\text{C}}{\text{Density of crude}} \right) - 131.5$$

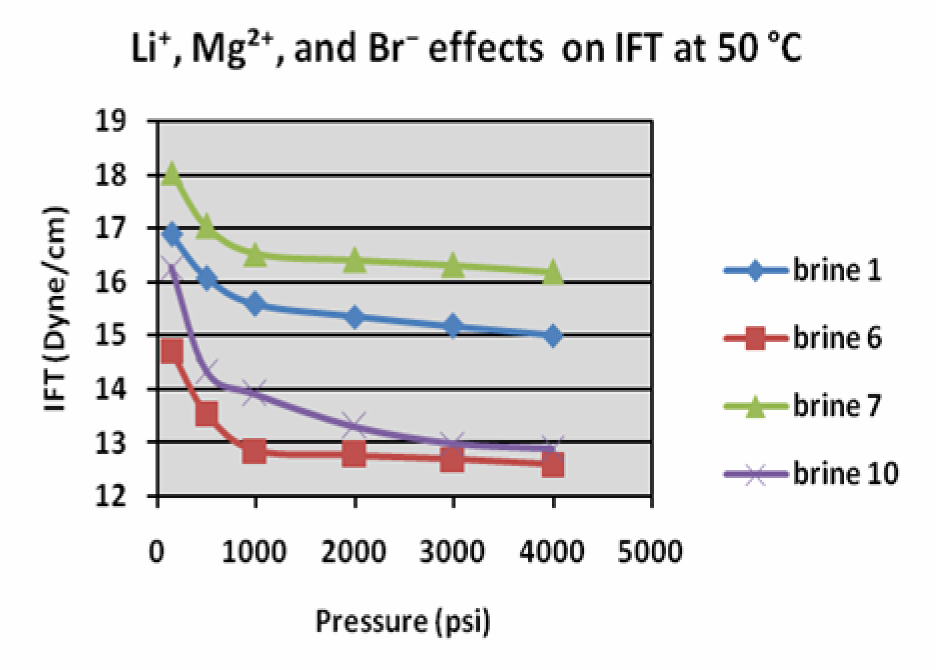
Viscosity is dependent of temperatures



Factors affecting interfacial tension: fluid-fluid interaction

- Oil compositions
- Formation water compositions
- Densities
- Pressure and temperature
- Emulsion





Oil-water

10.2 dynes/cm

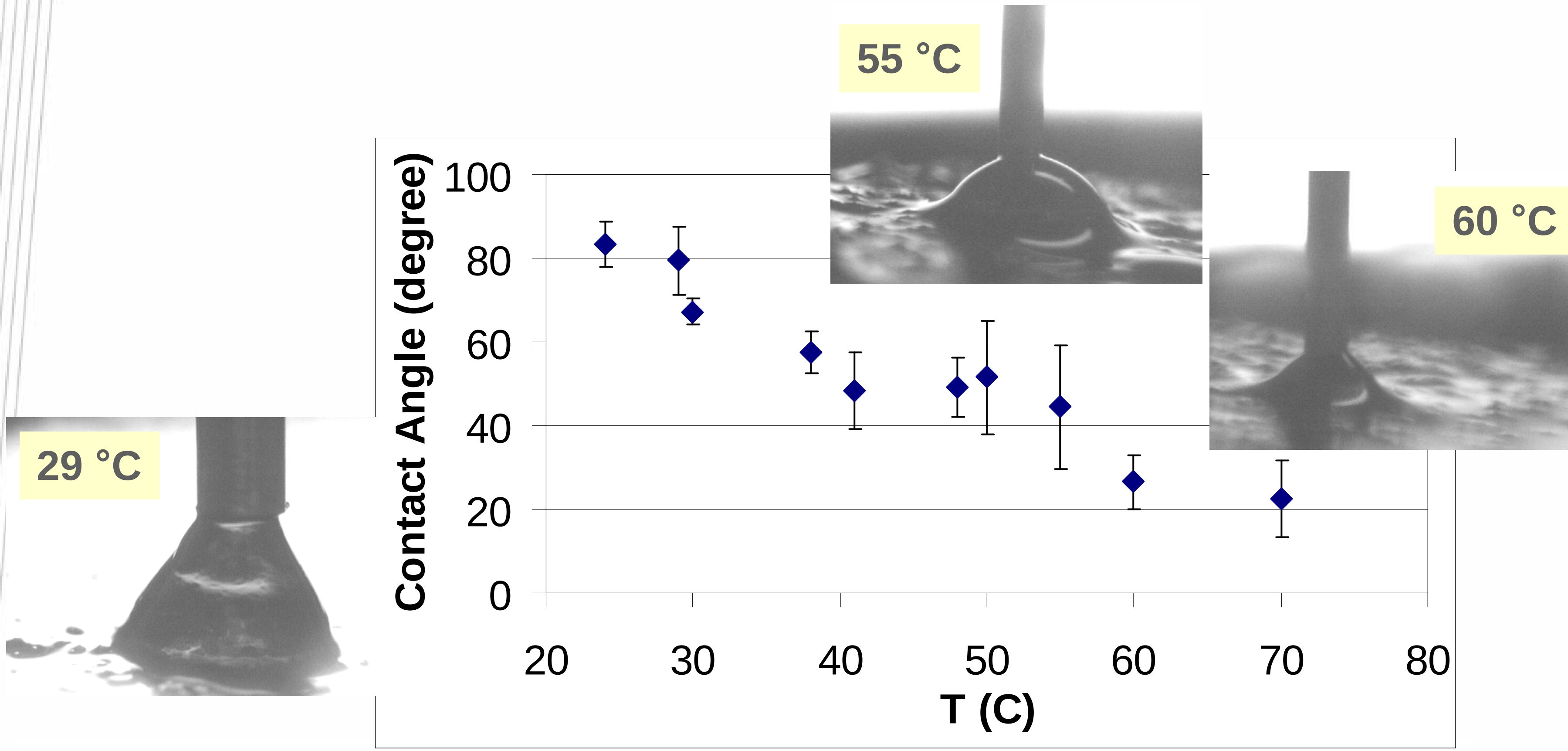
Oil-water+40 ppm biosurfactant

4.1 dynes/cm

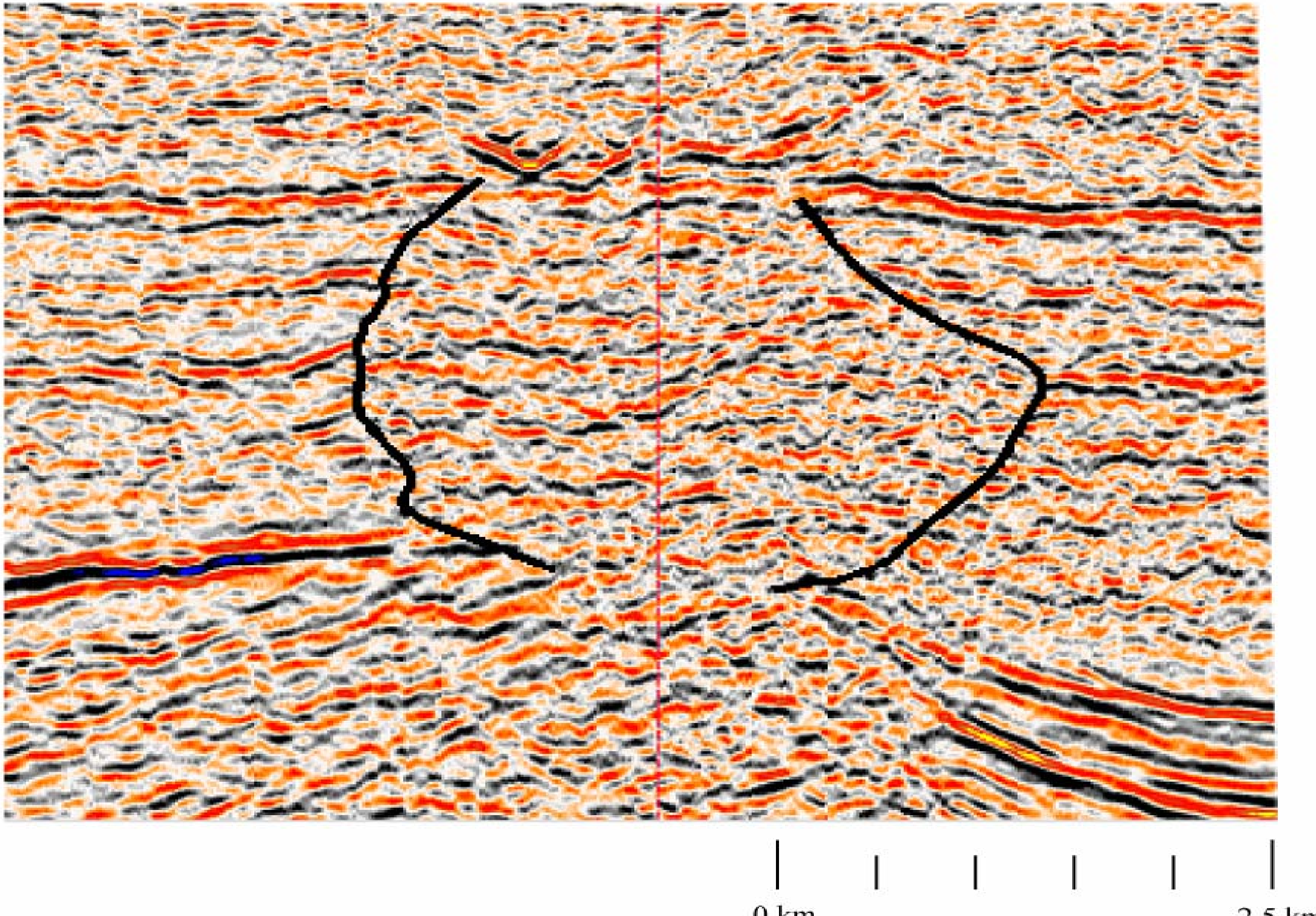
Factors affecting wettability : Fluid-rock interaction

$$Pc = 2\sigma COS\Theta / R$$

- Mineral types
- Fluid compositions
- Temperature

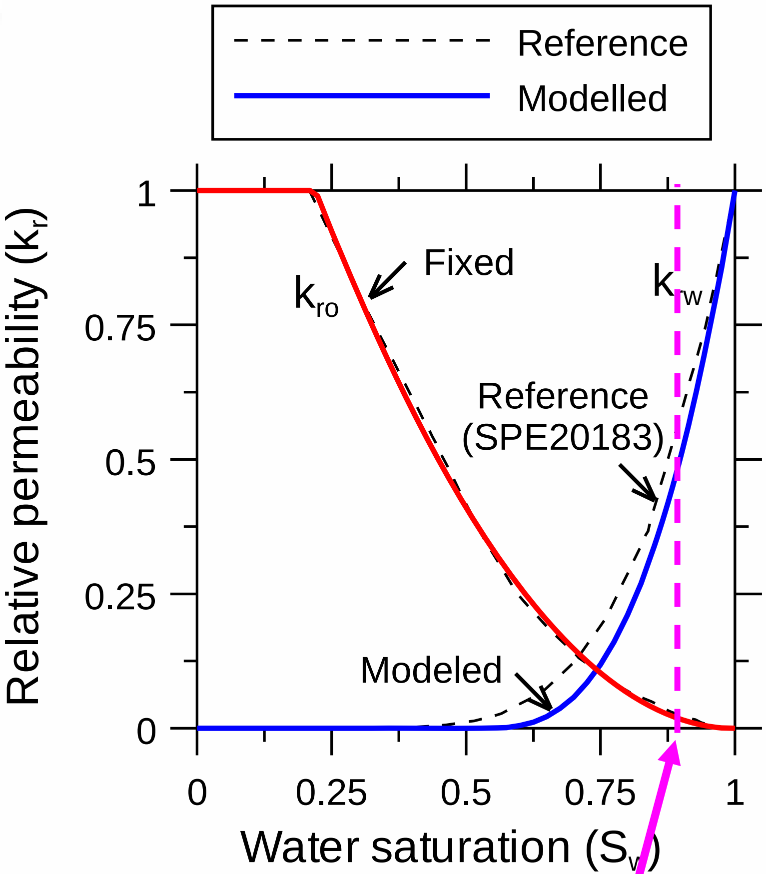


Preferential water leakage through seal: Fluid-rock interaction

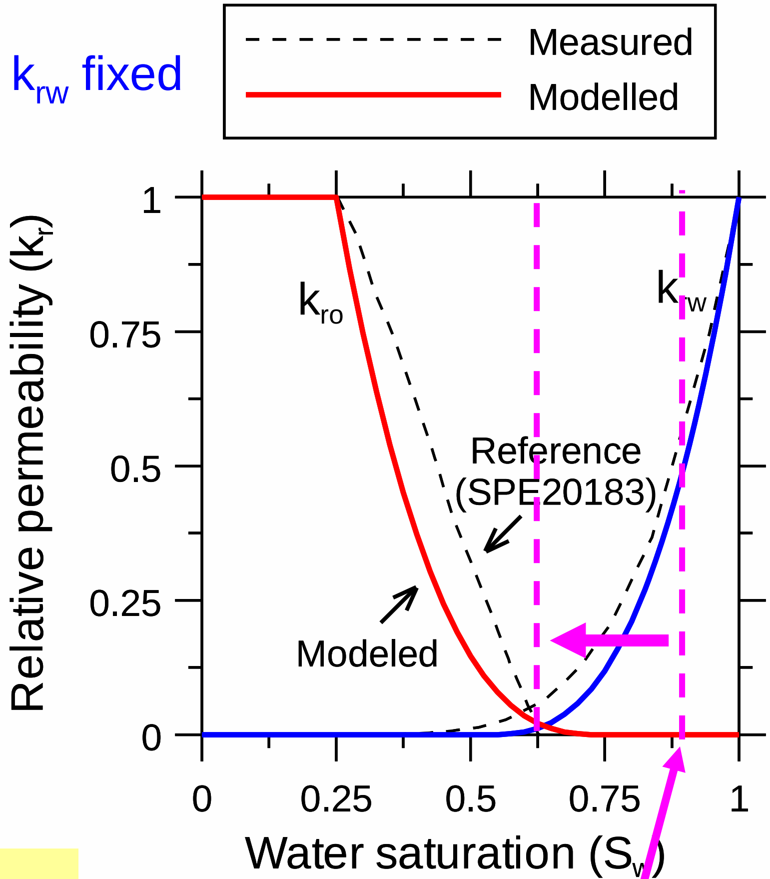


(Ref: Teige et al., 2009)

Relative permeability on oil migration and accumulation: Multiphase flow



k_{rw} fixed



So=10%

Schowalter (1979); England (1988)

So=10%

Laboratory investigation on secondary oil migration

- **Lenormand et al. (1988)**
- **Dembicki & Anderson (1989)**
- **Catalan et al. (1992)**
- **Thomas and Clouse (1995)**
- **Tokunaga et al. (2000)**
- **Luo et al. (2003)**

Investigate the effects of
Viscosity
IFT
Wettability

Water and oils used in the experiments

Oil	Density (g/cm3)	Viscosity (cp)	Interfacial Tension (dynes/cm)
Shell 15	0.85	23.7 (20°C)	
Decane	0.73	0.92 (20°C)	52 (decane/water)@24°C 23.5 (oil/air)
Dodecane	0.75	1.34 (25°C)	50.6 (oil/brine) 20.24 (dodecane/brine)

Brine used: 1.124g/cm^3

Glass bead grainsizes used (μm): Permeability effect

90-150* (Θ=135°)

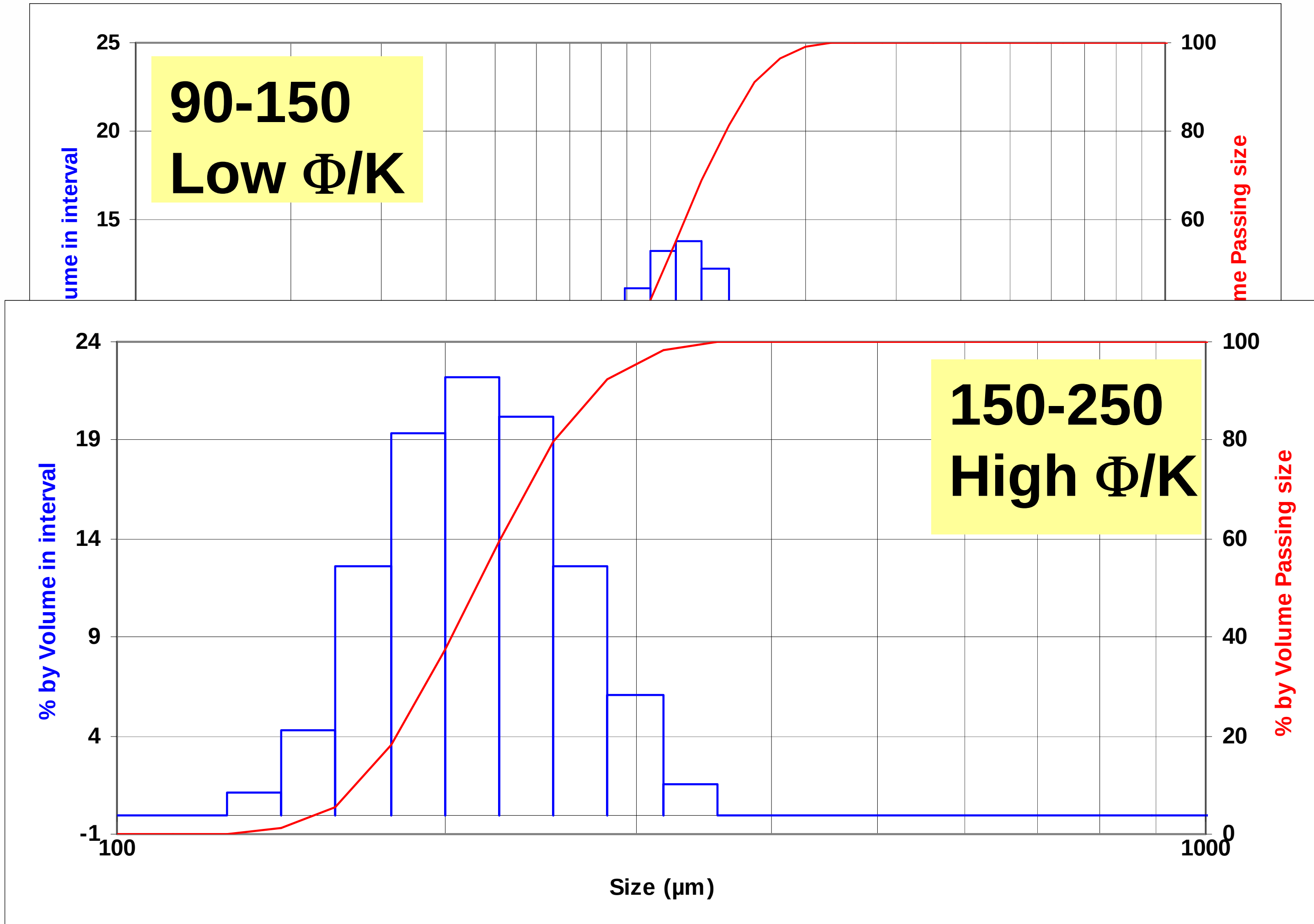
150-250

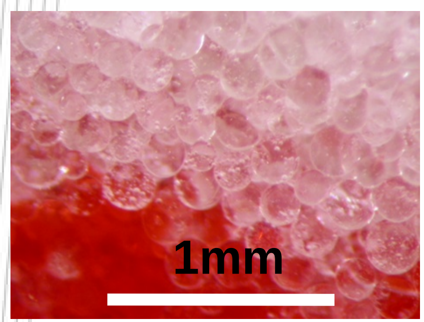
250-425

425-600

600-850

(Θ=45°)

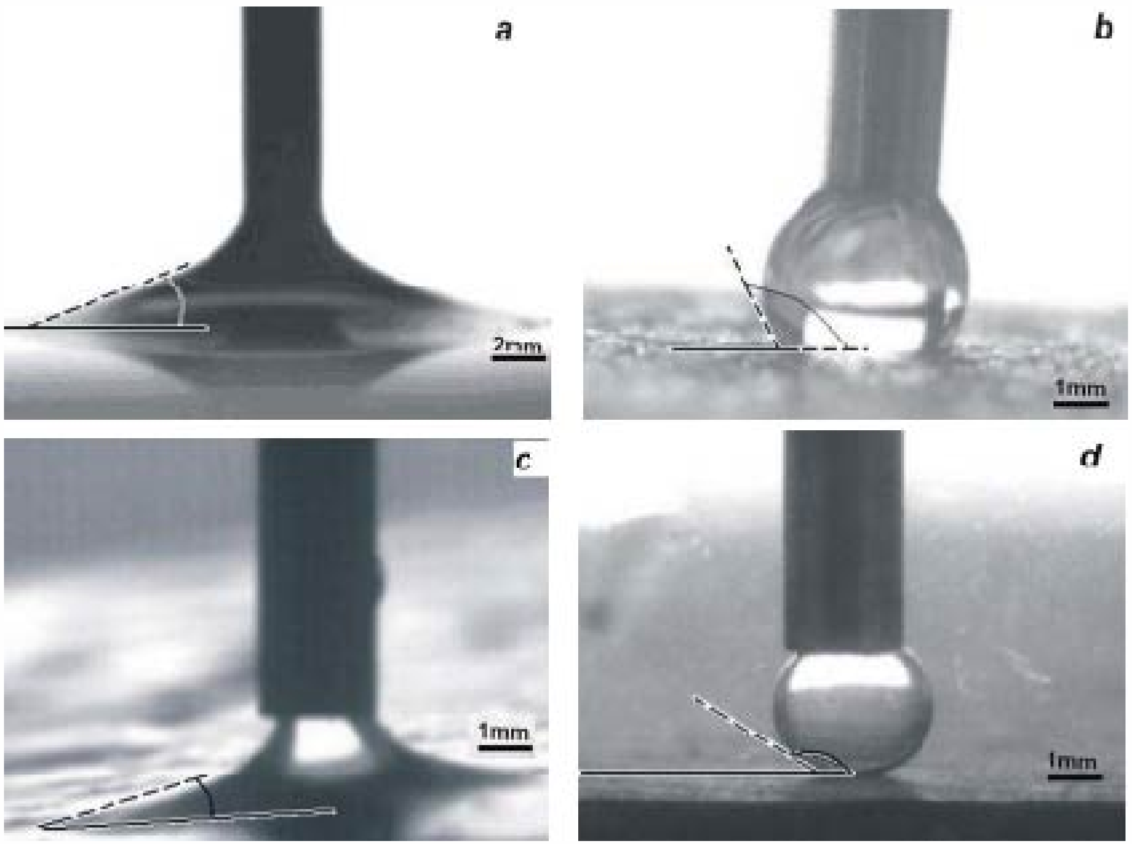




Wettability of glass beads used in the experiments

90-150
Oil wet

150-250
Water wet



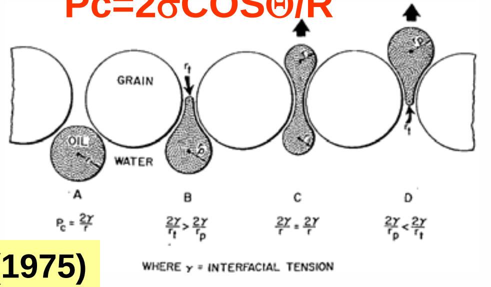
Predicted vs measured oil column heights: Wettability effect

$$h_{\min} = \frac{2\sigma(\frac{1}{r_t} - \frac{1}{R_b})}{g\Delta\rho}$$

$$R_b = (\frac{1}{2})(0.414D)$$

$$r_t = (\frac{1}{2})(0.154D)$$

Pc=2σCOSΘ/R



from Berg (1975)

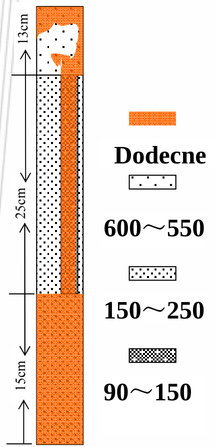
	Glass beads (μm)	Theoretical Minimum Height (cm)	Minimum height measured (cm)
1	90~150*	134.7～224.4	<0.5
2	150~250	80.8～134.7	37.8
3	250~425	47.5～80.8	
4	425~600	33.7～47.5	13.5

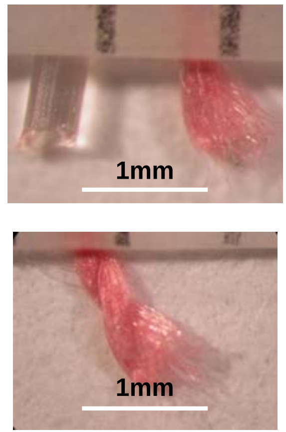
Presenter's notes: And then we found Berg has brought forward a equation to predict minimum height for migration in closet packing and rhoromber . here σ is interfacial tension between two immiscible fluid. D is glass beads diameter, Rb maximum pore throat, rt minimum pore throat. $\Delta\rho$ *is density difference. G is gravity acceleration.*

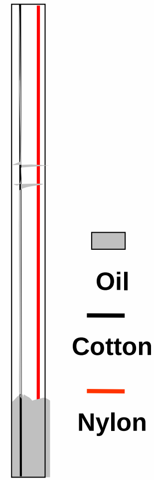
Here, *the minimum height calculated by this methods provide some beneficial guide.*

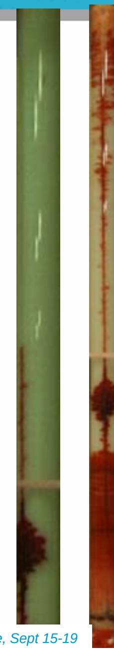
But in fact, in our experiments, the measured minimum height is much lower than theoretic value. So there is must something ignored in this equation. That is the wettability.

Wettability strongly affects oil migration and accumulation





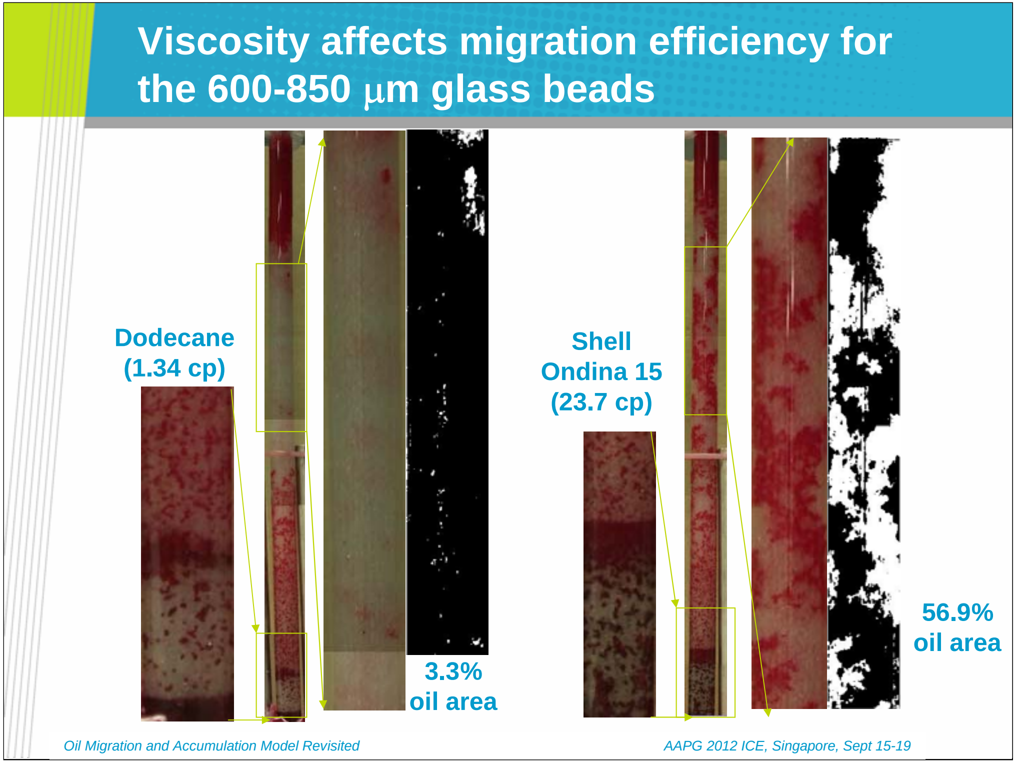




Experiment 33

Experiment 10

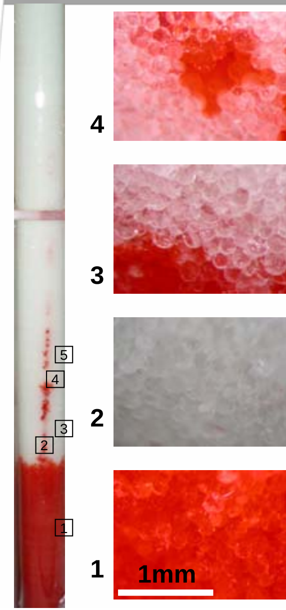
Presenter's notes: When we employ oil wet media, there is total different story. Oil is quite easy to migrate along them to the top of glass tube. The glass beads with grain size of 90-150 micron are oil-wet, whose contact angle is 130~140. The cotton bread are cluster of fibers, which are oil wet and porous media, as contrast, nylon is water wet and non porous media. in experiment 10, we deploy nylon and cotton bread parallel to the glass tube. oil only go up along the cotton bread.



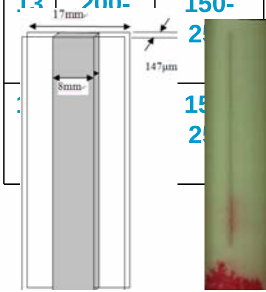
Presenter's notes: Same glass beads(600-850 microns), same volume of oil injected(15cm height oil column), with different viscosity(1.34, 23.7cp).

The bigger the viscosity of oil, The more the residual oil in pathway, less the hydrocarbon migration efficiency is. Most hydrocarbon are assumed to migrate in light oil with lower viscosity in underground. The heavy oil reservoir are mostly produced by post-accumulation physical-chemical process.

Viscosity affects oil migration rates



	Slit width （μm）	Glass beads （μm）	Filling Mode	Oil	Rate (mm/min）
12	200-210	150-250	slurry	Dodecane	2.5
13	200-	150-25	slurry	Shell Ondina 15	0.65
1		15 25			4.72



EXPERIMENT 26
Migration rate:
12～20 mm/min

Presenter's notes: Fracture, of course, will consist of the high way for oil migration. Under the fractures made same way, in same glass beads and same filling, different oil has different migration rate: decane and dodecane has same migrate rate, which is one order higher than shell 15

While the migration rate can be higher in smooth fractures made by two glace slices sticked together. So we think the roughness degree of fracture surface actually can effect migration rate a lot.

Summary of OMP and coreflooding experiments

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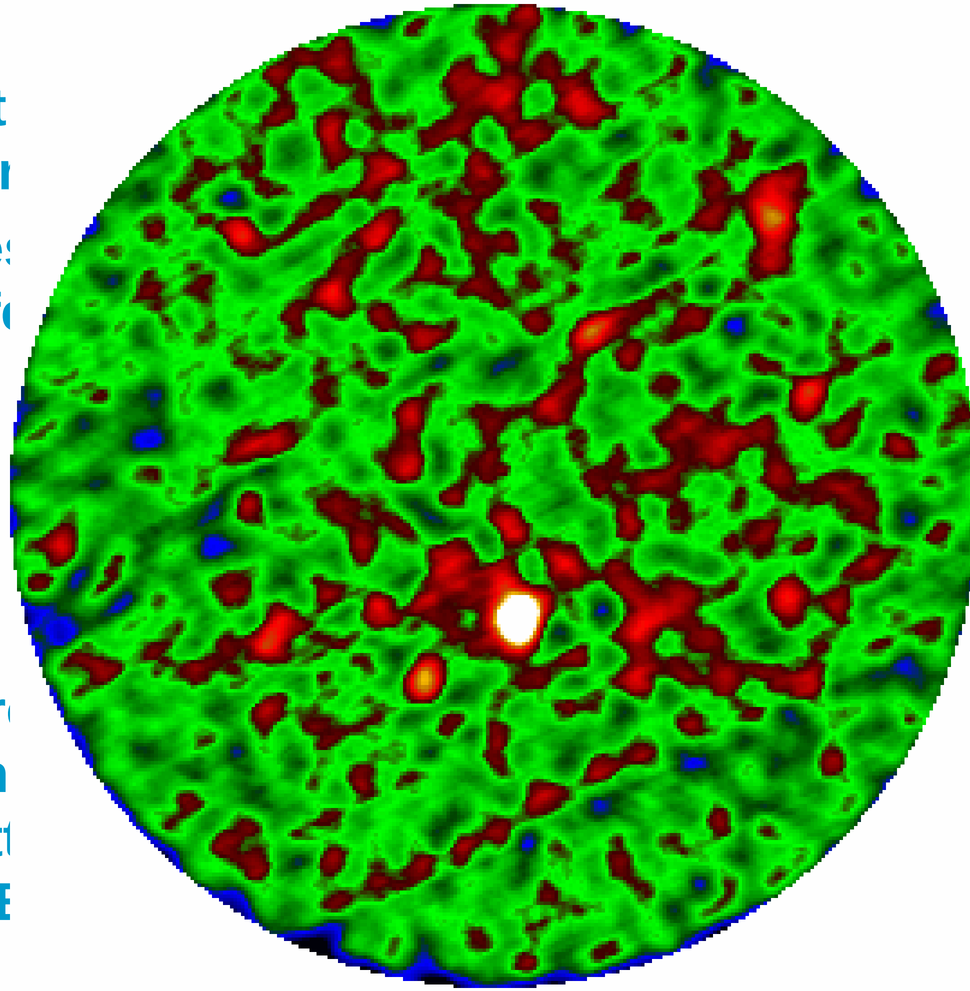
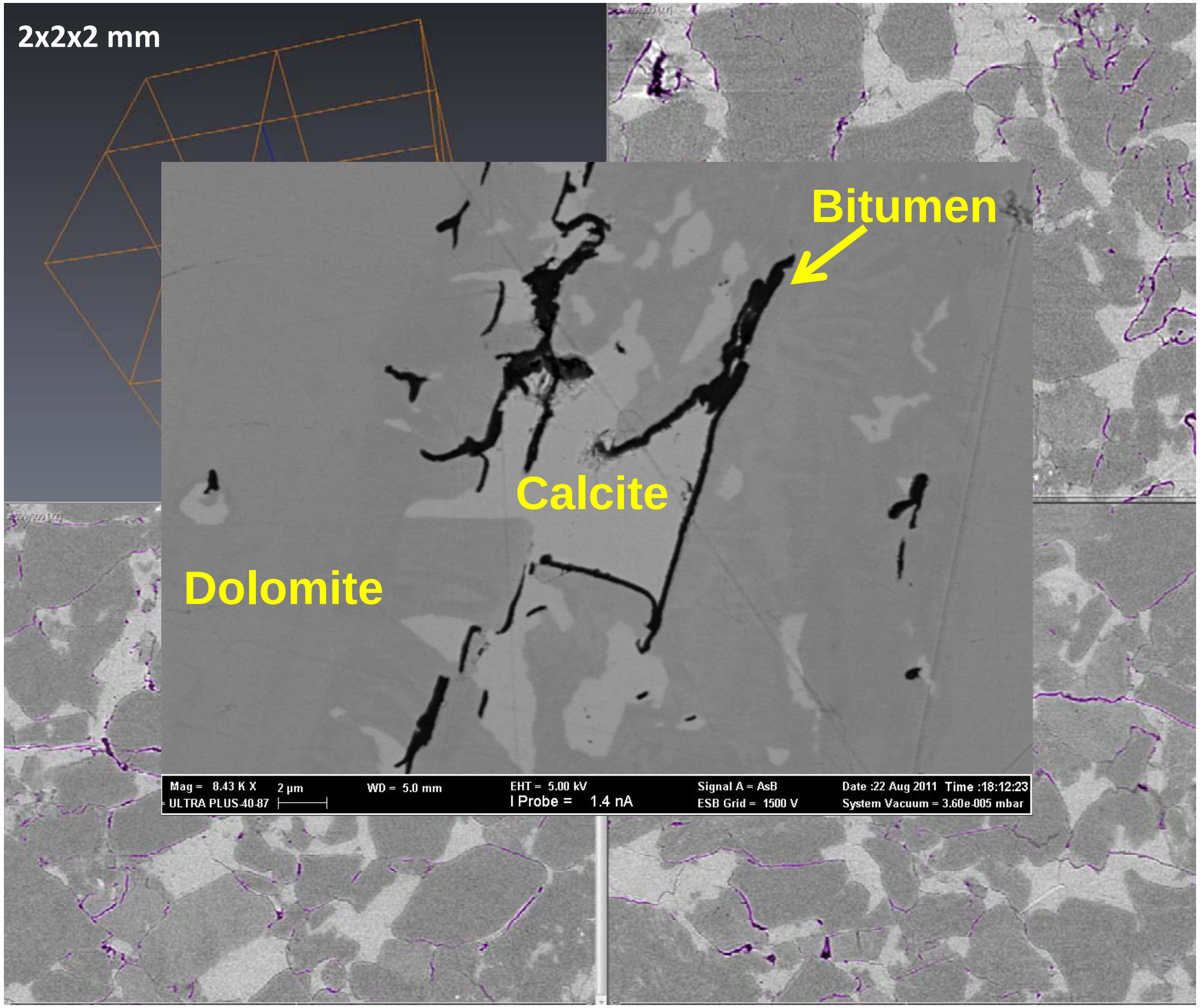


- Cor ... r PT
  con ... sity,
  wet ... eat effects
  on E ... ons

Pc=2σCOSΘ/R; **Nc=vμ/σ**

Tight oil and gas accumulations

Tight oil and gas reservoirs in northern Tarim Basin



Gas condensate

Cretaceous

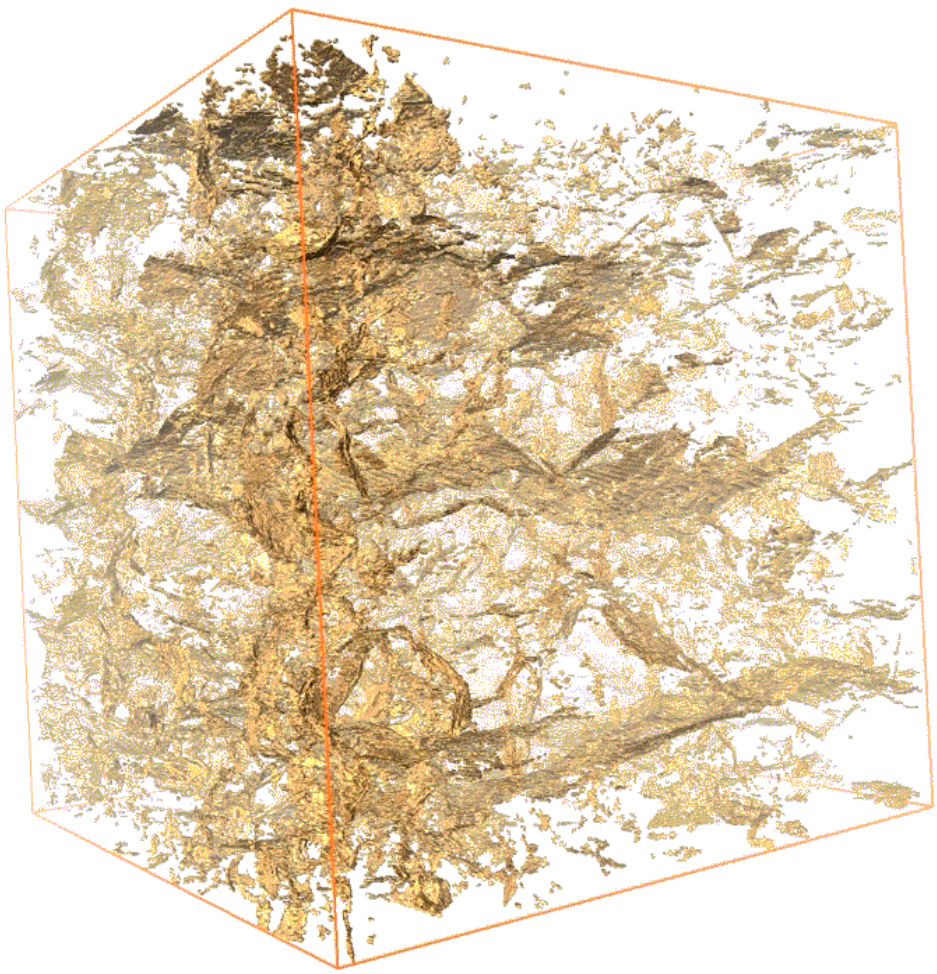
>6000 m

Φ<5%

K<1 mD

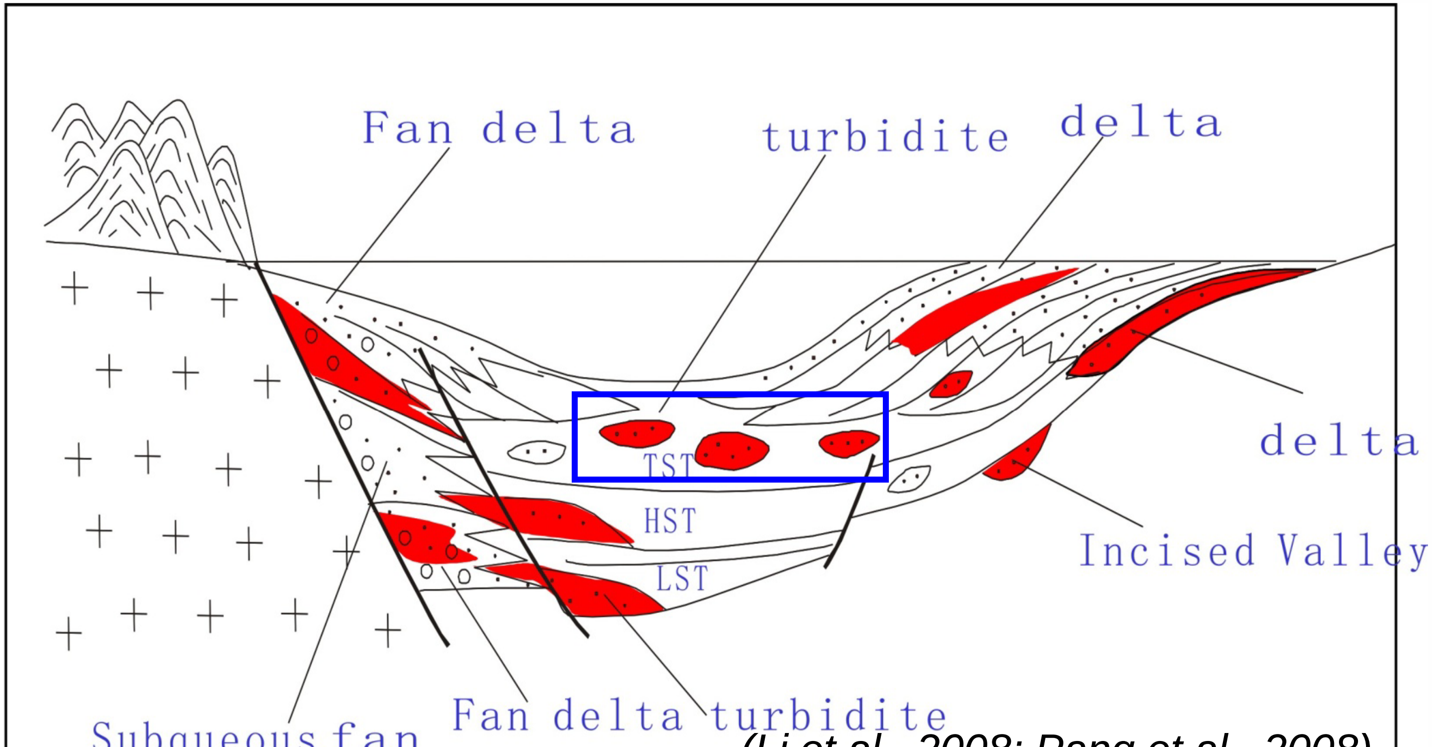
Pores filled with bitumen from an early hydrocarbon charge prior to reservoir cementation act as later HC transport conduits

Bitumen network in tight sandstone reservoir



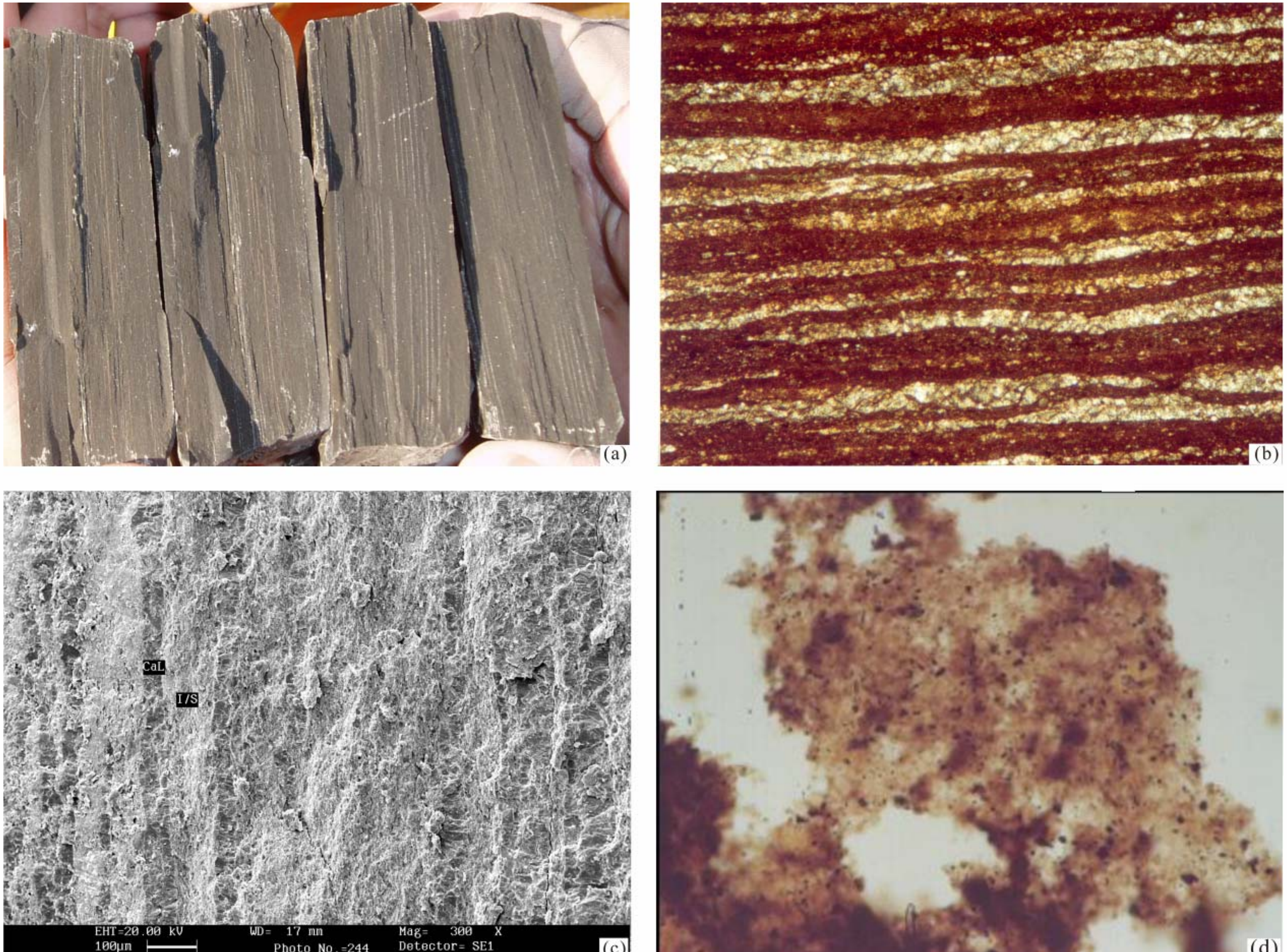
Lenticular basin floor turbidte subtle traps: Jiyang Basin, Eastern China

- **Oil generated from Es4 migrated 100s of metres through an immature source rock (Es3) to reach the 4-way closure traps**
- **Wettability may have played an important role in the postulated oil migration through organic network**

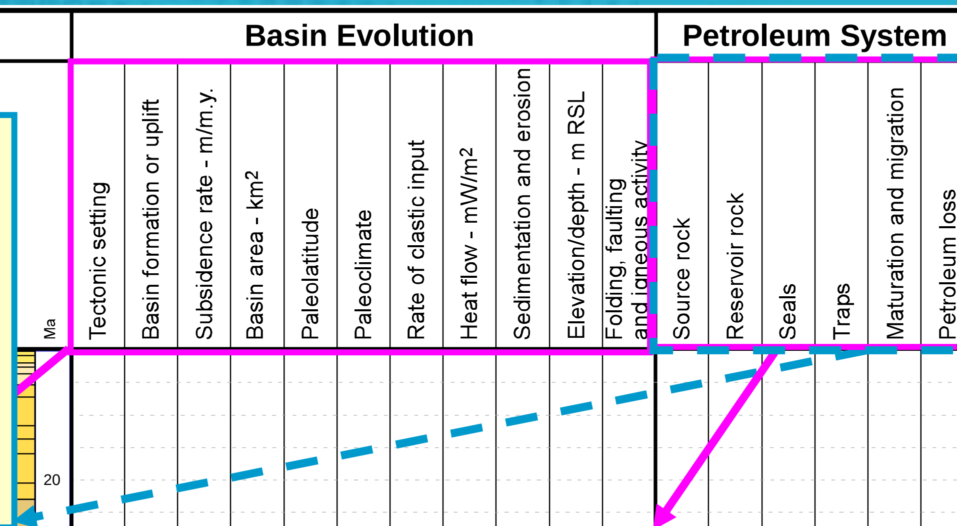


(Li et al., 2008; Pang et al., 2008)

Source rock heterogeneity at various scales: Kerogen network as oil migration conduits



An holistic approach to petroleum system analysis *(modified from USGS chart)*



Oil Migration and Accumulation

- Reservoir Heterogeneity
- Petrophysics & Geomechanics
- Fluid properties
- Fluid-fluid, -rock interaction
- PVT factors

Basin Evolution										
Tectonic setting	Basin formation or uplift	Subsidence rate - m/m.y.	Basin area - km^2	Paleolatitude	Paleoclimate	Rate of clastic input	Heat flow - mW/m^2	Sedimentation and erosion	Elevation/depth - m RSL	Folding, faulting and igneous activity

Petroleum System					
Source rock	Reservoir rock	Seals	Traps	Maturation and migration	Petroleum loss

Summary

- **The traditional permeability-control model is inadequate**
- **Hydrocarbon migration and accumulation is a dynamic process from source kitchen to reservoirs as compositions and PVT conditions are changing**
  - P/T conditions
  - Variations of formation fluid properties (density and viscosity)
  - Compositions of formation fluids (e.g. formation water, hydrocarbon fractionation, GOR)
  - Fluid-fluid interaction: IFT
  - Fluid-rock interaction: Wettability
- **Hydrocarbon migration and accumulation model should consider all the above parameters**

$$Pc=2\sigma COS\Theta/R; \quad Nc=v\mu/\sigma$$

Acknowledgements

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Thank you

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