دانشگاه سمنان

Enhanced Oil Recovery

Lecturer:

Dr Lotfollahi

Oil recovery techniques

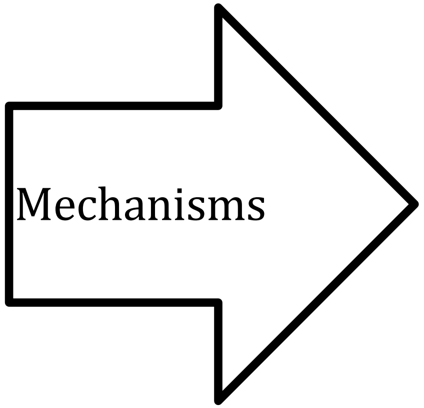
Oil recovery operations traditionally have been subdivided into three stages:

- **Primary Stage**
- **Secondary Stage**
- **Tertiary Stage**

Tertiary Stage oil recovery

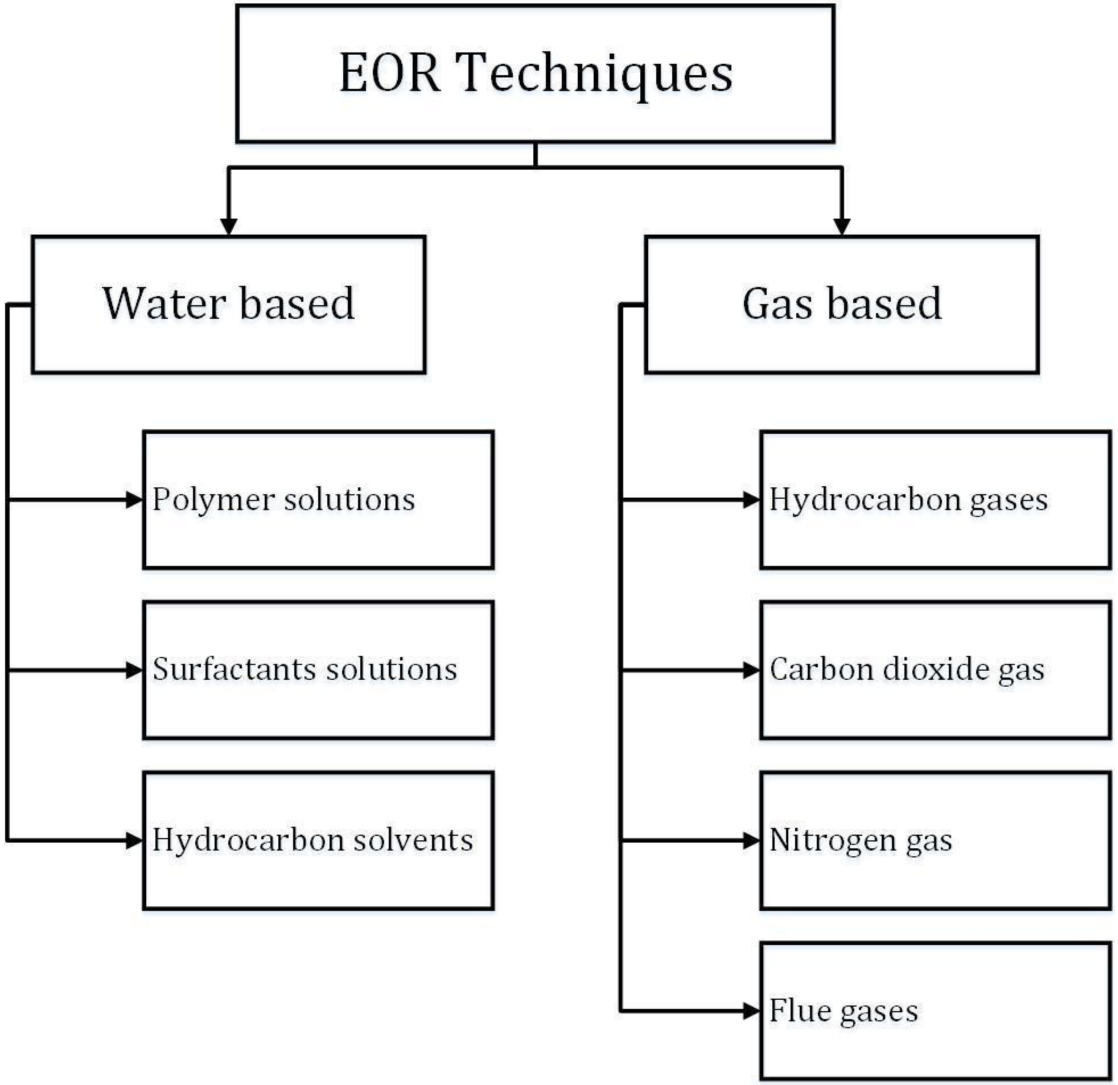
The third stage of production is that obtained after whatever secondary process was used. In tertiary processes generally make use of:

- **Miscible gases Injection**
- **Chemicals**
- **Thermal energy**



- ✓ Oil swelling
- ✓ Oil viscosity reduction
- ✓ Favorable phase behavior
- ✓ IFT reduction

EOR techniques:


EOR Techniques

Water based

- Polymer solutions
- Surfactants solutions
- Hydrocarbon solvents

Gas based

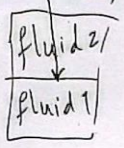
- Hydrocarbon gases
- Carbon dioxide gas
- Nitrogen gas
- Flue gases

EOR techniques

In EOR processes, the injected fluids interact with the reservoir rock and oil system to create conditions favorable for oil recovery. These interactions result into the following **mechanisms**:

- **Lowering IFT**
- **Oil swelling via diffusion and dispersion**
- **Oil viscosity reduction**
- **Wettability modification**
- **Mobility ratio modification**
- **Favorable phase behavior**

surface Tension referes to The forces on the interface of fluid_Air



IFT refers To the Force between Two Fluids (water-oil) or a gas-fluid interface. (light hc - oil)

{gas-water
gas-oil
CO_2-oil

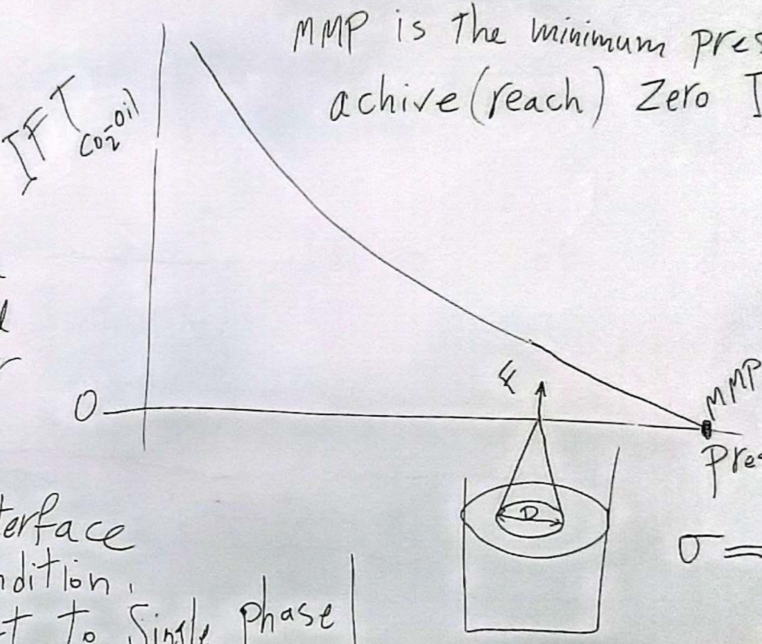
IFT ⟶ 0 ⟹ we dont have interface

≡ miscible Condition.

Two phases Convert to Single phase

3) MMP: Minimum Miscibility pressure.

MMP is the minimum pressure to achive (reach) Zero IFT



x1000

cgs → cm, gr, sec

$\left[\frac{dyne}{cm}\right]$

$$\sigma = \frac{F}{\pi D}\left[\frac{N}{m}\right]$$

یا $\frac{mN}{m}$

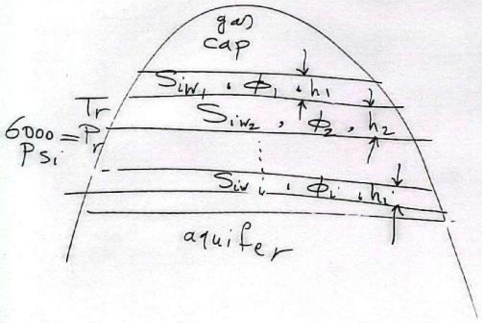
4) water saturation, fraction.

$$S_{iw} = \frac{\text{The volume of water in porous}}{\text{Total pore volume.}}$$

$$\left\{\begin{array}{l} T = 68\,^\circ F \\ P = 1\,bar \\ \quad = 14.7\,psi \end{array}\right.$$

empty.

$$1 - S_{iw} = S_{io} = \frac{\text{The volume of oil in porous media}}{\text{Total pore volume}}$$



n = No of Layers.

$$N = \frac{7758\,A}{B_{oi}} \sum_{i=1}^{n} \underset{\to ft}{h_i} \phi_i \left(1 - S_{wi}\right)$$

A : $\boxed{\text{acres}}$, 43,560 ft^2

5) B_{oi} : formation volum

factor : $\frac{rb}{stb}$

compressibility of petroleu

$B_{oi} = 0.9$

$$\frac{1}{0.9} \simeq 1.1$$

on the surface.

EOR methods include:

- **Water flooding**
- **Thermal methods**: steam stimulation, steam flooding, hot water drive, and in-situ combustion
- **Chemical methods**: polymer,surfactant,caustic,and miscellar /polymer flooding.
- **Miscible methods**: hydrocarbon gas,CO2,and nitrogen (flue gas and partial miscible/immiscible gas injection may also be considered)

EOR Methods

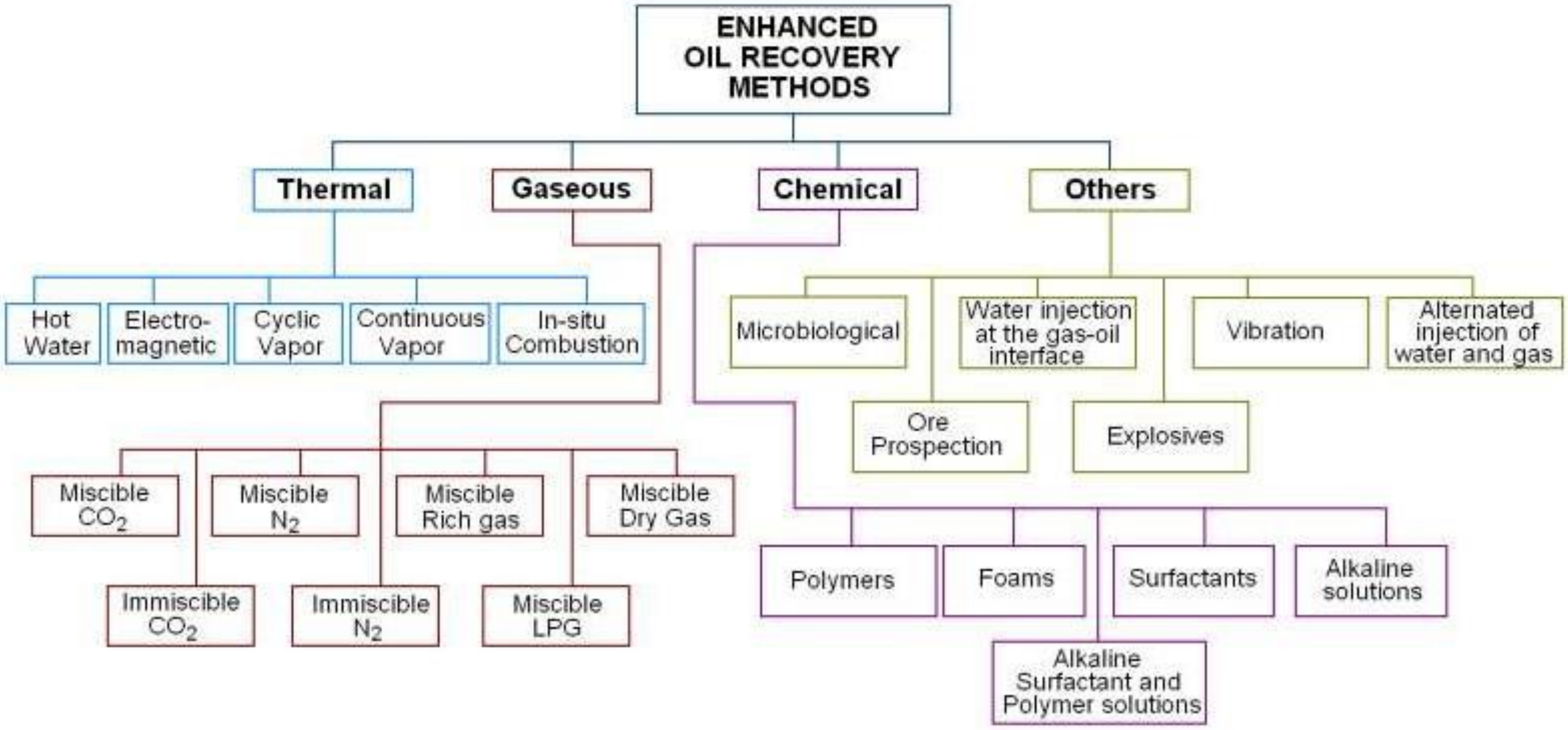
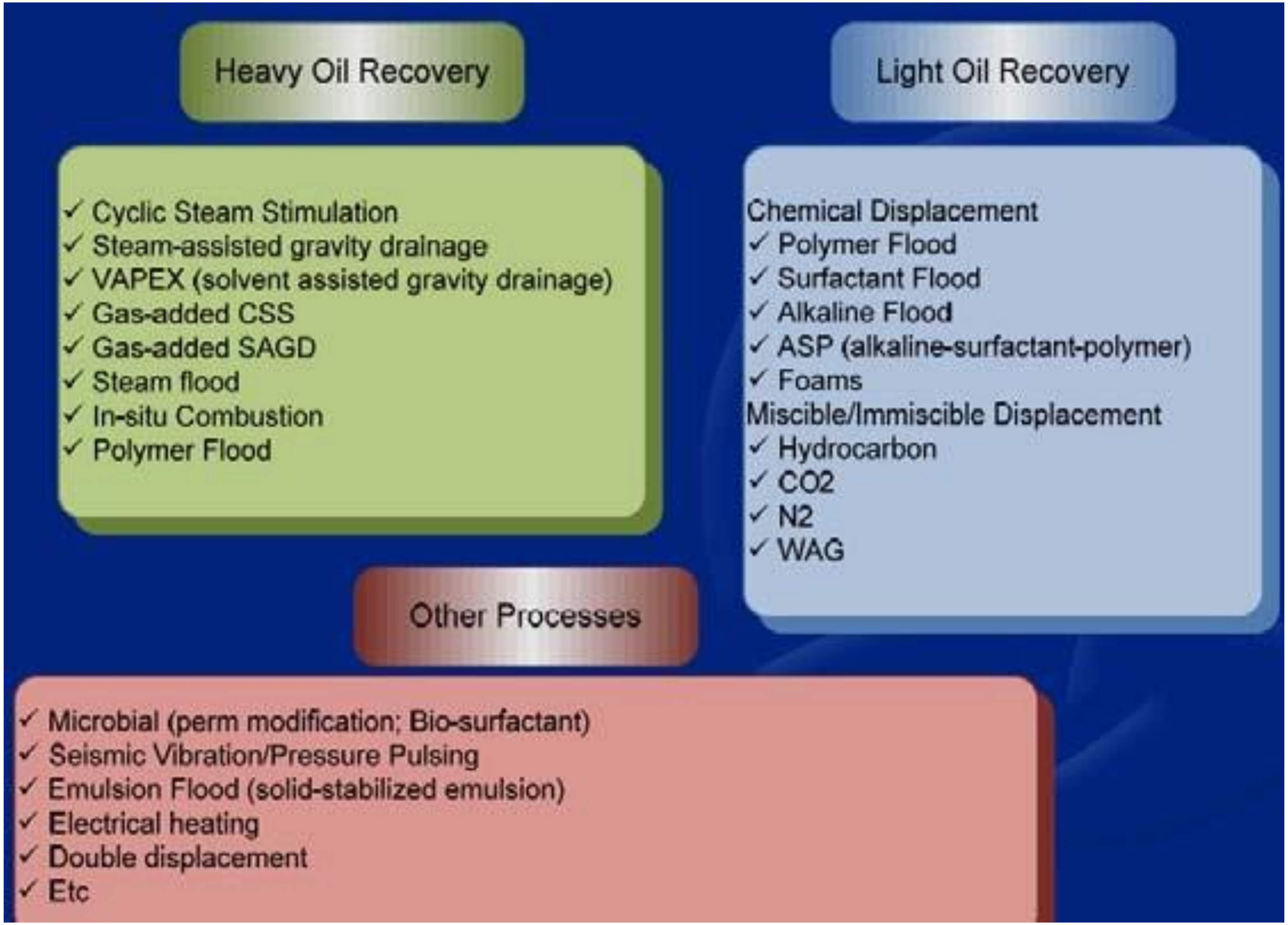


Figure 1. Some enhanced oil recovery methods (LPG = liquefied petroleum gas).



Heavy Oil Recovery

- ✓ Cyclic Steam Stimulation
- ✓ Steam-assisted gravity drainage
- ✓ VAPEX (solvent assisted gravity drainage)
- ✓ Gas-added CSS
- ✓ Gas-added SAGD
- ✓ Steam flood
- ✓ In-situ Combustion
- ✓ Polymer Flood

Light Oil Recovery

Chemical Displacement

- ✓ Polymer Flood
- ✓ Surfactant Flood
- ✓ Alkaline Flood
- ✓ ASP (alkaline-surfactant-polymer)
- ✓ Foams

Miscible/Immiscible Displacement

- ✓ Hydrocarbon
- ✓ CO2
- ✓ N2
- ✓ WAG

Other Processes

- ✓ Microbial (perm modification; Bio-surfactant)
- ✓ Seismic Vibration/Pressure Pulsing
- ✓ Emulsion Flood (solid-stabilized emulsion)
- ✓ Electrical heating
- ✓ Double displacement
- ✓ Etc

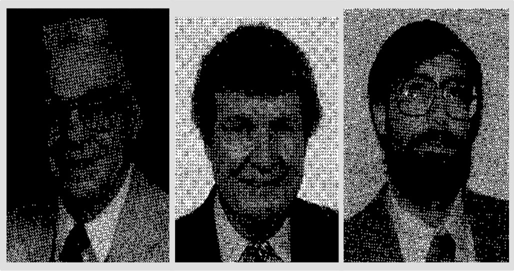
Screening Criteria Revisited- Part 1: Introduction to Screening Criteria and Enhanced Recovery Field Projects

J.J. Taber, SPE, **F.D. Martin,** SPE, and **R.S. Seright,** SPE,

New Mexico Petroleum Recovery Research Center

SPE Reservoir Engineering, August 1997 189-198

Taber Martin Seright



Summary

all Screening criteria have been proposed for enhanced oil recovery (EOR) methods. Data from EOR projects around the world have been examined and the optimum characteristics for successful projects have been noted. Steam flooding is still the dominant EOR method. All chemical flooding has been declining, but polymers and gels are being used successfully for sweep improvement and water shutoff. Only C02 flooding activity has increased continuously.

. 2—Oil gravity range of oil that is most effective for EOR methods. Relative production (BID) is shown by size of type.

	Oil properties			**Reservoir characteristic**					
EOR method	**Gravity** (API)	**Viscosity** (cp)	**composition**	**Oil saturation**	**Formation type**	**Net thickness** (ft)	**Average Permeability** (md)	**Depth** (ft)	**Temparature** (f)
Gas Injection Method (miscible)									
Nitrogen And Flue Gas	>23-41	<0.4-0.2	High % of C1 to C7	>40-75	Sandstone Or Carbonate	Thin unless dipping	NC	>6000	NC
Hydrocarbon	>23-41	<3-0.5	High % of C2 to C7	>30-80	Sandstone Or Carbonate	Thin unless dipping	NC	>4000	NC
CO2	>22-36	<10-1.5	High % of C5 to C12	>20-55	Sandstone Or Carbonate	Wide range	NC	>2500	NC
Immiscible Gases	>12	<600	- NC	>35-70		Good vertical K	NC	>1800	NC
(Enhanced) waterflooding									
Polymer, Alkaline Flooding	>20-35	<35-13	Light Some organic Acids for Alkalina	>35-53	Sandstone Preferred	NC	>10-450	>9000 To 3250	>200-80
Polymer flooding	>15	<150 >10	NC	>50-80	Sandstone Preferred	NC	>10-800	<9000	>200-140
Thermal/Mechanical									
Combustion	>10-16	<5000 to 1200	Some asphaltic Components	>50-72	High porosity sand/sandston	>10	>50	>11500 To 3500	>100-135
Steam	>8-13	<200000 to 4700	NC	>40-56	High porosity sand/sandston	>20	>200-2540	>4500 to 1500	NC
Surface mining	>7-11	Zero Cold flow	NC	>	Tar sand	>10	NC	NC	NC

CO$_2$-miscible
non-U.S.

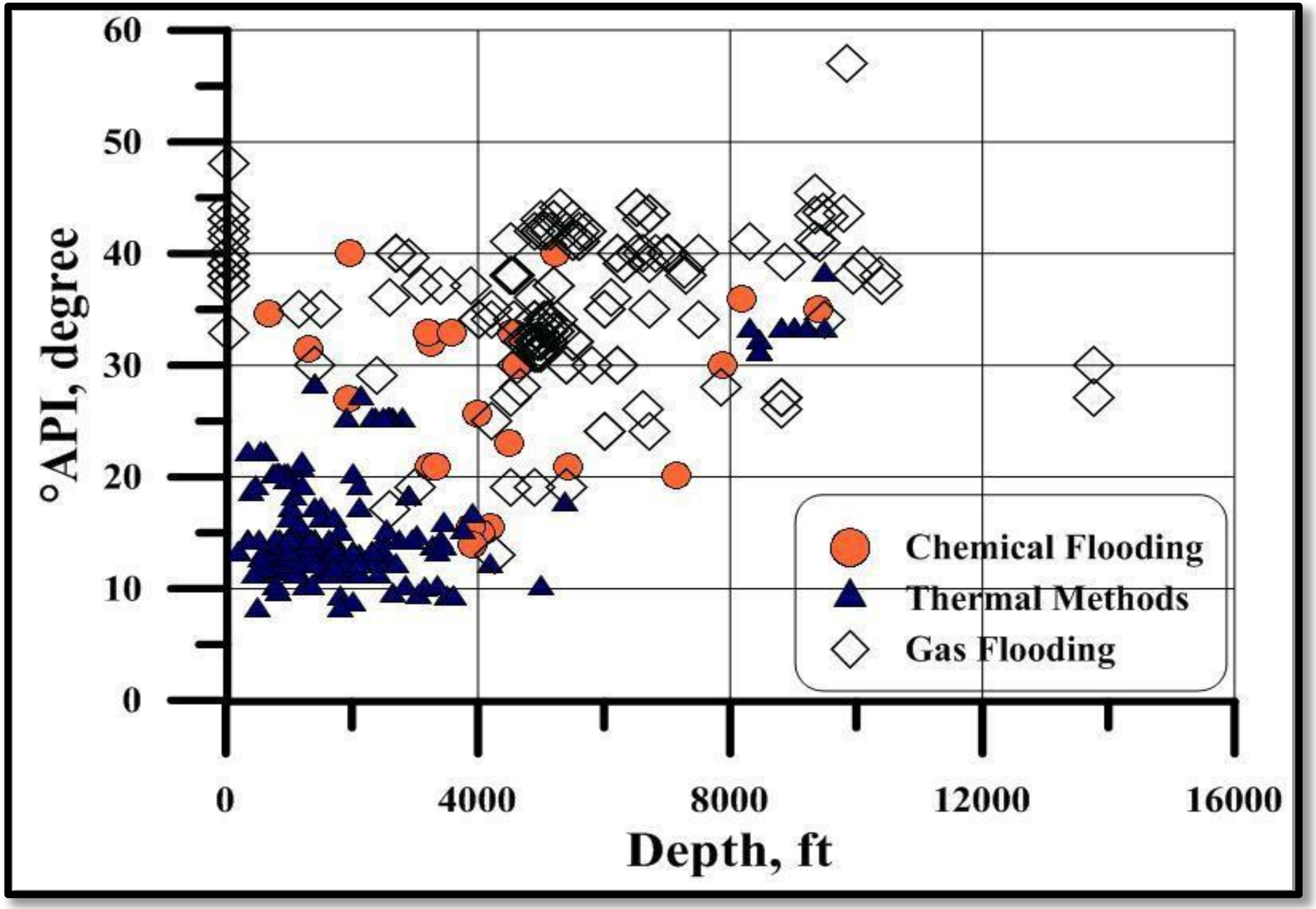


Figure 1-1- the study of enhanced oil recovery project, by considering depth and API (Halliburton)

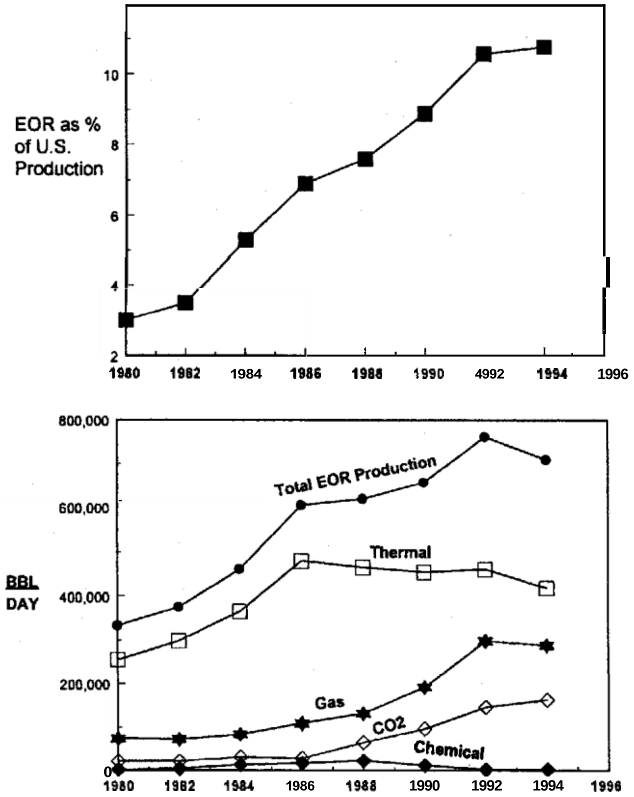


Fig. 1-EOR production in the U.S. (data from Ref. 25).

TABLE 1—CURRENT AND PAST EOR METHODS	
Method	Table Number (in Ref. 16)
Gas (and Hydrocarbon Solvent) Methods	
"Inert" gas injection	
Nitrogen injection	1
Flue-gas injection	1
Hydrocarbon-gas (and liquid) injection	2
High-pressure gas drive	
Enriched-gas drive	
Miscible solvent (LPG or propane) flooding	
CO_2 flooding	3
Improved Waterflooding Methods	
Alcohol-miscible solvent flooding	
Micellar/polymer (surfactant) flooding	4
Low IFT waterflooding	
Alkaline flooding	4
ASP flooding	4
Polymer flooding	5
Gels for water shutoff	
Microbial injection	
Thermal Methods	
In-situ combustion	6
Standard forward combustion	
Wet combustion	
02-enriched combustion	
Reverse combustion	
Steam and hot-water injection	7
Hot-water flooding	
Steam stimulation	
Steamflooding	

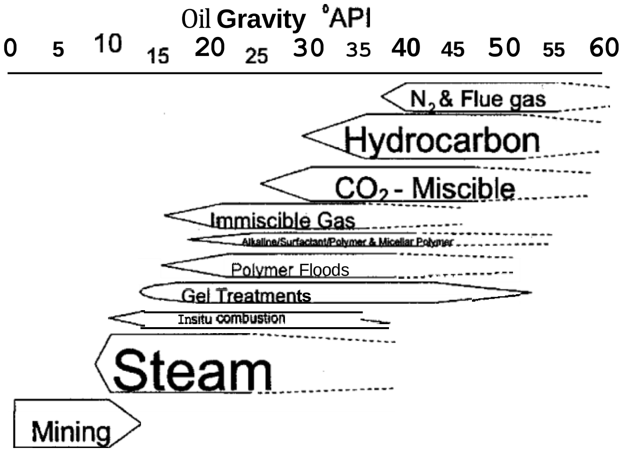


Fig. 2—Oil gravity range of oil that is most effective for EOR methods. Relative production (BID) is shown by size of type.

TABLE 2-CLASSIFICATION OF CURRENT ENHANCED RECOVERY METHODS*
Solvent extraction and/or "miscible-type" processes
Nitrogen and flue gas
Hydrocarbon-miscible methods
CO_2 flooding
"Solvent" extraction of mined, oil-bearing ore
IFT reduction processes
Micellar/polymer flooding (sometimes included in miscible-type flooding above)
ASP flooding
Viscosity reduction (of oil) or viscosity increase (of driving fluid) processes plus pressure
Steamflooding
Fireflooding
Polymer flooding
Enhanced gravity drainage by gas or steam injection
'Classified by the main mechanism of oil displacement (excluding gel treatments).

TABLE 3-SUMMARY OF SCREENING CRITERIA FOR EOR METHODS

		Oil Properties			Reservoir Characteristics					
Detail Table in Ref. 16	EOR Method	Gravity (°API)	Viscosity (cp)	Composition	Oil Saturation (% PV)	Formation Type	Net Thickness (ft)	Average Permeability (md)	Depth (ft)	Temperature (°F)
Gas InjectionMethods(Miscible)										
1	Nitrogenand flue gas	>35↗48↗	<0.4↘0.2↘	High percent of C_1 to c7	>40↗75↗	Sandstone or carbonate	Thin unless dipping	NC	>6,000	NC
2	Hydrocarbon	>23↗41↗	<3↘0.5↘	High percent of C_2 to C_7	>30↗80↗	Sandstone or carbonate	Thin unless dipping	NC	>4,000	NC
3	CO_2	>22↗36↗ [a]	<10↘1.5↘	High percent Of C_5 to C_{12}	>20↗55↗	Sandstone or carbonate	Wide range	NC	>2,500[a]	NC
1–3	Immiscible gases	> 12	< 600	NC	>35↗70↗	NC	NC if dipping and/or good vertical permeability	NC	> 1,800	NC
		(E hanced) Wate flooding								
4	Micellar/ Polymer, ASP, and Alkaline Flooding	>20↗35↗	<35↘13↘	Light, intermediate, some organic acids for alkalinefloods	>35↗53↗	Sandstone preferred	NC	>10↗450↗	>9,000↘3,250	>200↘80
5	Polymer Flooding	>15	<150, >10	NC	>50↗80↗	Sandstone Dreferred	NC	>10↗800↗ [b]	<9,000	>200↘140
Thermal/Mechanical										
6	Combustion	>10↗16→? 1 —	<5,000 ↓ 1,200	Some asphaltic components	>50↗72↗	High-porosity sand/ sandstone	>10	>50[c]	<11,500↘3,500	>100↗135
7	Steam	> 8 to 13.5→?	<200,000 ↓ 4,700	NC	>40↗66↗	High-porosity sand/ sandstone	>20	>200↗2,540↗[d]	<4,500↘1,500	NC
—	Surface mining	7 to 11	Zero coldflow	NC	>8 wt% sand	Mineable tar sand	>10[e]	NC	>3 1 overburden to sand ratio	NC

NC=not critical.

Underlinedvalues represent the approximatemean or average for current field projects.

[a] See Table 3 of Ref. 16.

[b] > 3md from some carbonatereservoirs if the intent is to sweep only the fracture system.

Transmissibility > 20 md-Wcp

[d] Transmissibility > 50 md-Wcp

[e] See depth.

meth-

CO2-miscible

non-U.S.

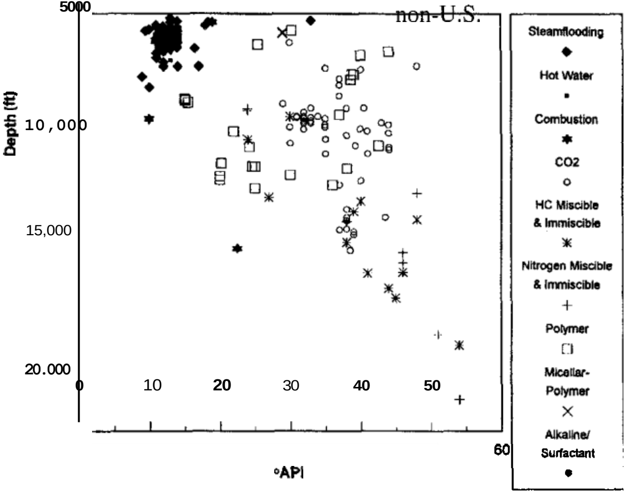


Fig. 3—Depth and oil gravity of producing EOR projects in the U.S. (data from Ref. 25).

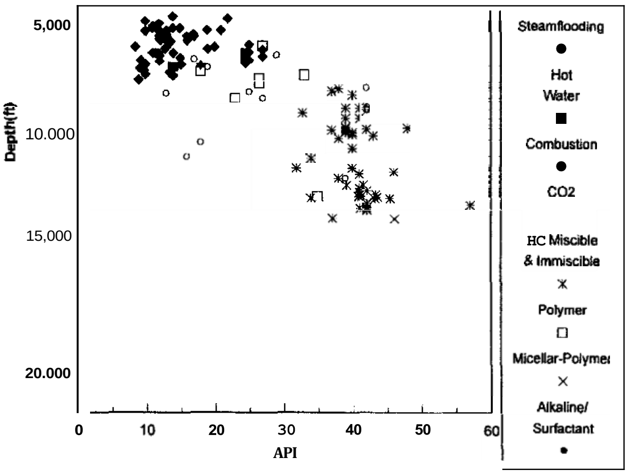


Fig. 4—Depth and oil gravity of producing EOR projects outside the U.S. (data from Ref. 25).

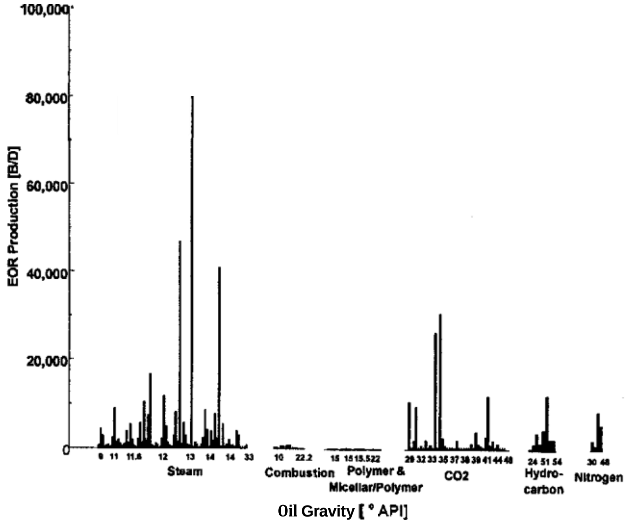


Fig. 5EOR productionvs. oil gravity in the U.S. (data from Ref. 24).

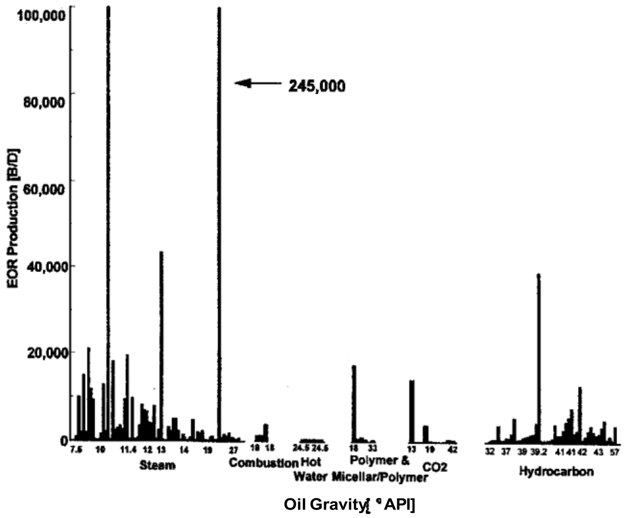


Fig. 6-EOR production vs. oil gravity outside the U.S. (data from Ref. 25).

floods, > ↗48↗ means that the process should
35 35°API work with oils

ed. They are considered together because the pressures required (MMP) for good displacement are similar,[26] and it appears that they

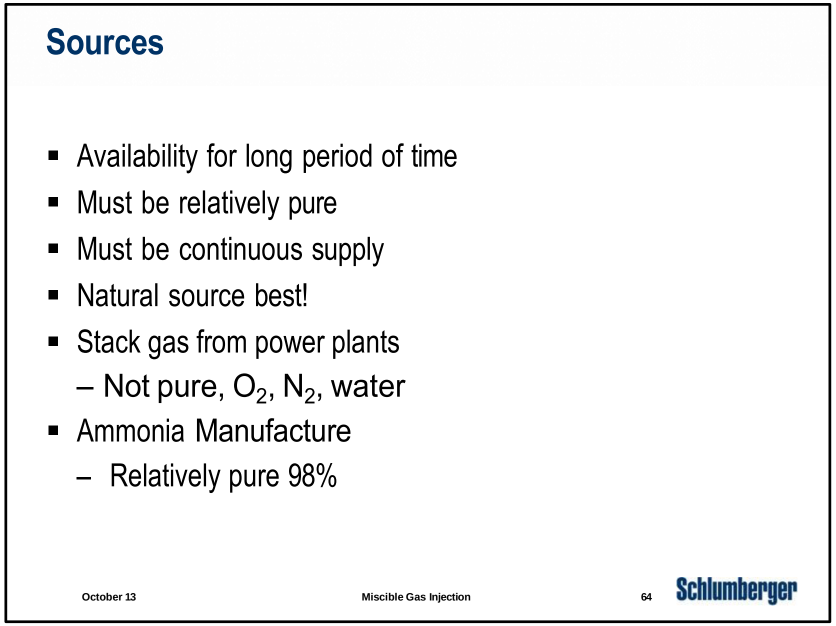
EOR processes:

Regardless of the mechanisms involving in EOR processes, they classified into five categories:

- **Mobility control processes**
- **Chemical processes**
- **Miscible processes**
- **Thermal processes**

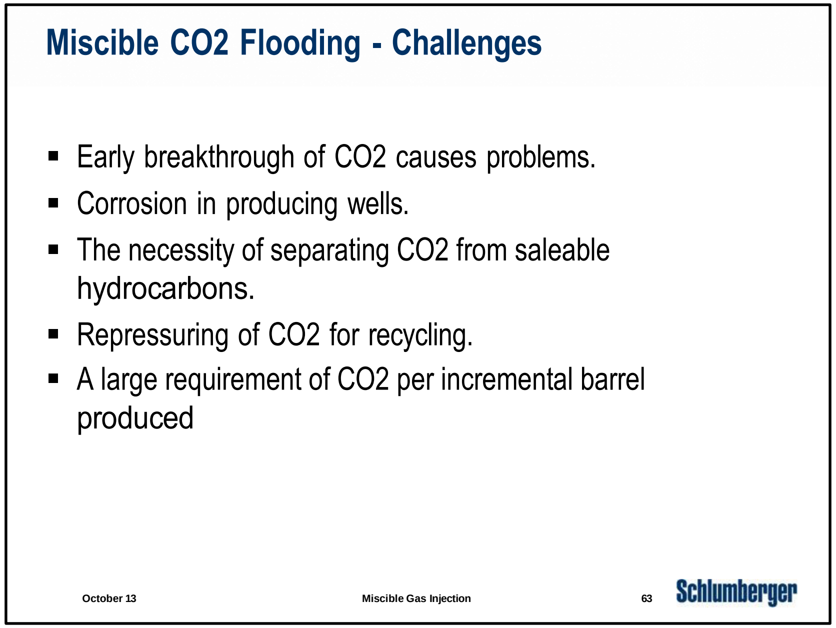
Other processes

Only C02 flooding activity has increased continuously.



Sources

- Availability for long period of time
- Must be relatively pure
- Must be continuous supply
- Natural source best!
- Stack gas from power plants
  - Not pure, O_2, N_2, water
- Ammonia Manufacture
  - Relatively pure 98%



Miscible CO2 Flooding - Challenges

- Early breakthrough of CO2 causes problems.
- Corrosion in producing wells.
- The necessity of separating CO2 from saleable hydrocarbons.
- Repressuring of CO2 for recycling.
- A large requirement of CO2 per incremental barrel produced

Screening Reservoirs for CO_2 Miscible EOR

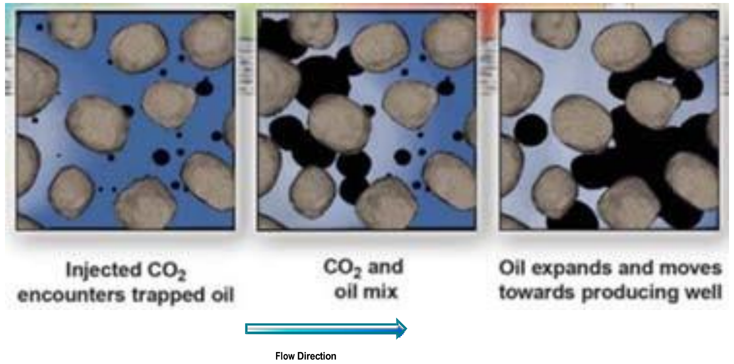
- Oil Properties
  - API Gravity: > 25, Ideal 36
  - Viscosity : < 10 cp, Ideal < 1.5 cp
  - Composition: High percentage of C_5 and C_{12}
- Reservoir Properties
  - Depth: >2500 ft
  - Pressure: > 1500 psi (P_{res}>MMP ; P_{inj} < P_{frac})
  - Temperature: Low enough for miscibility
  - Gas Cap: Small to none.
  - Heterogeneity: Low
  - Oil Saturation: >20%, Ideal >55%
  - Permeability: > 1 mD
  - Formation Type: Carbonate or sandstone
- Site
  - Large volumes of CO_2 are available

Conditions for CO_2 Flooding

- Stock tank oil gravity: 15º to 45º API
- Reservoir temperature: 80 – 300 ºF
- Reservoir Pressure: 1,000 - > 4,000 psia

- Sandstone & Carbonate reservoirs
- Thickness <10’ to 100s’

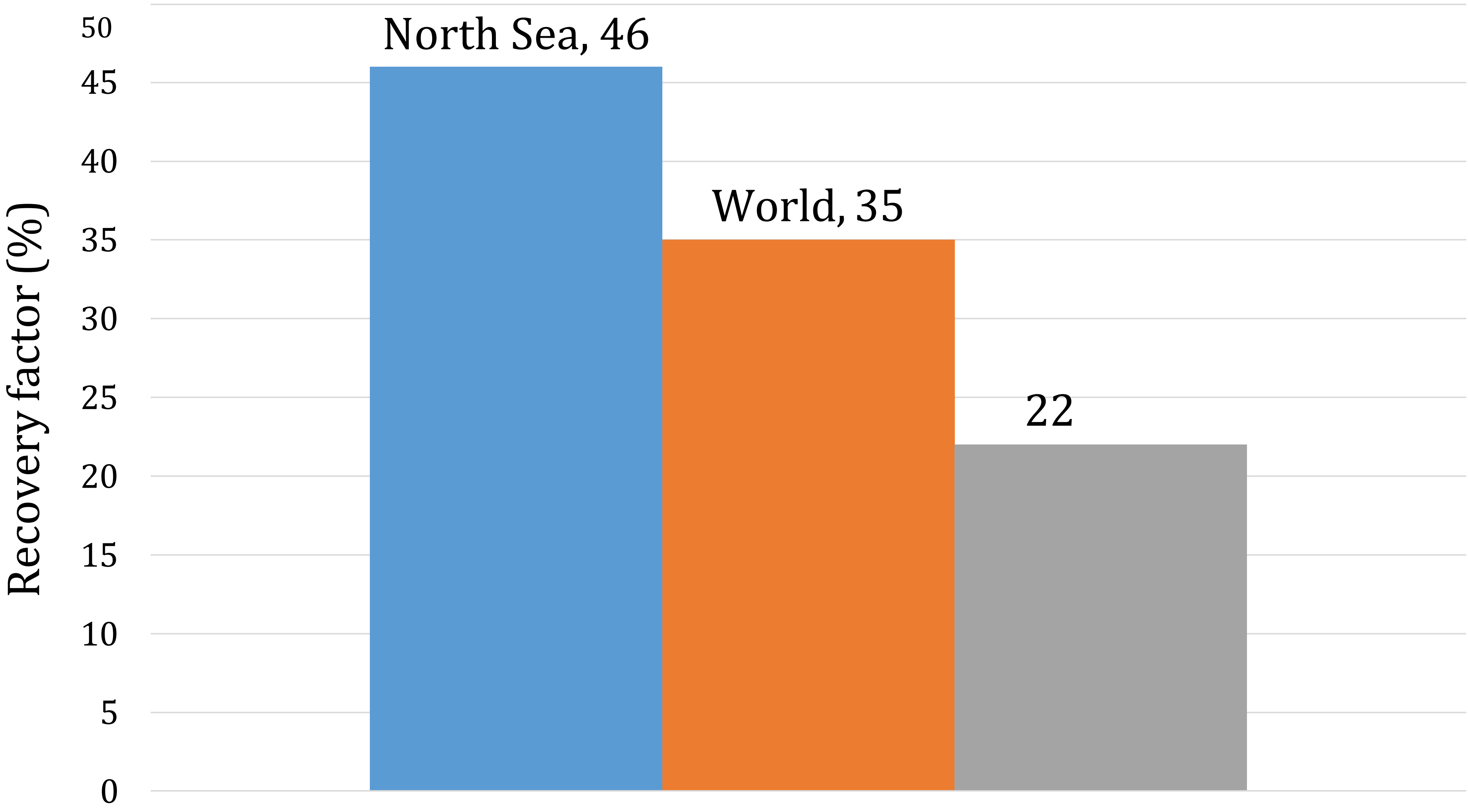
Mechanisms for CO_2



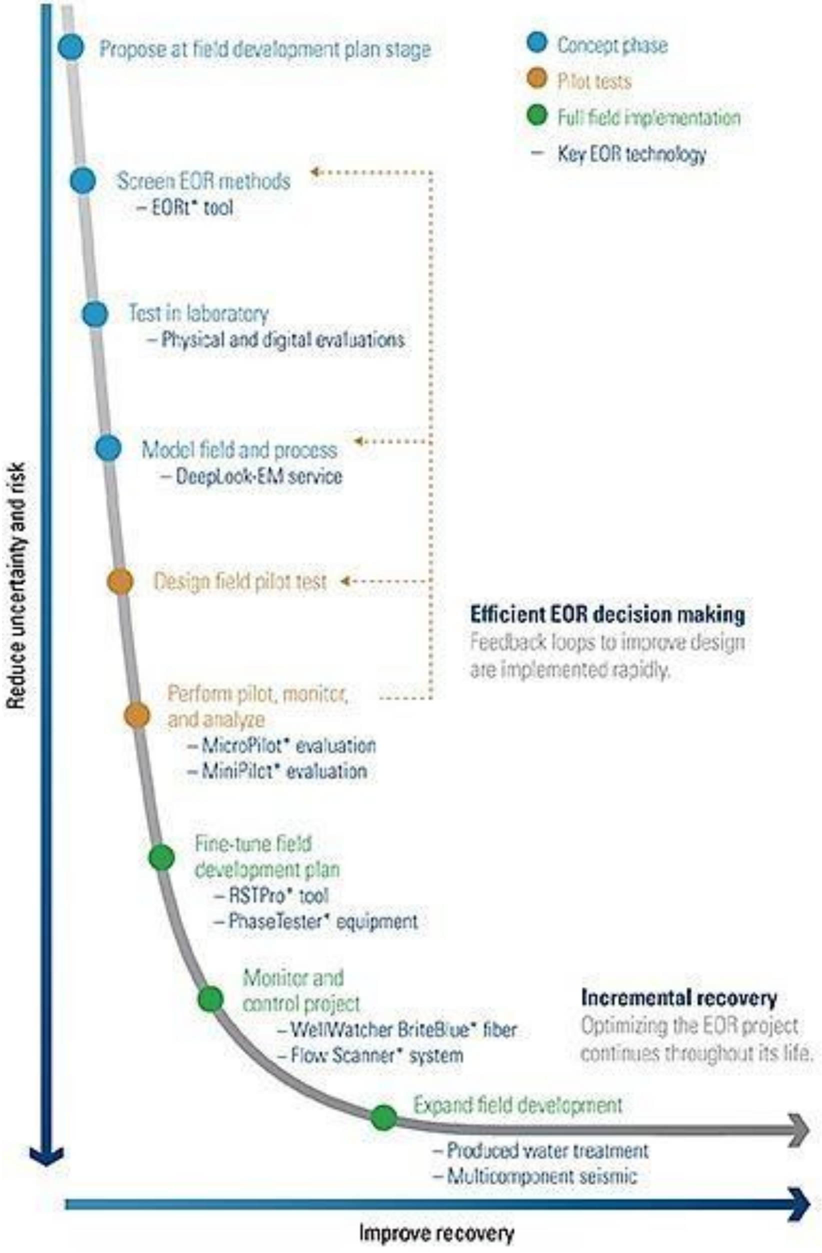
Recovery Mechanisms for CO_2 Flooding

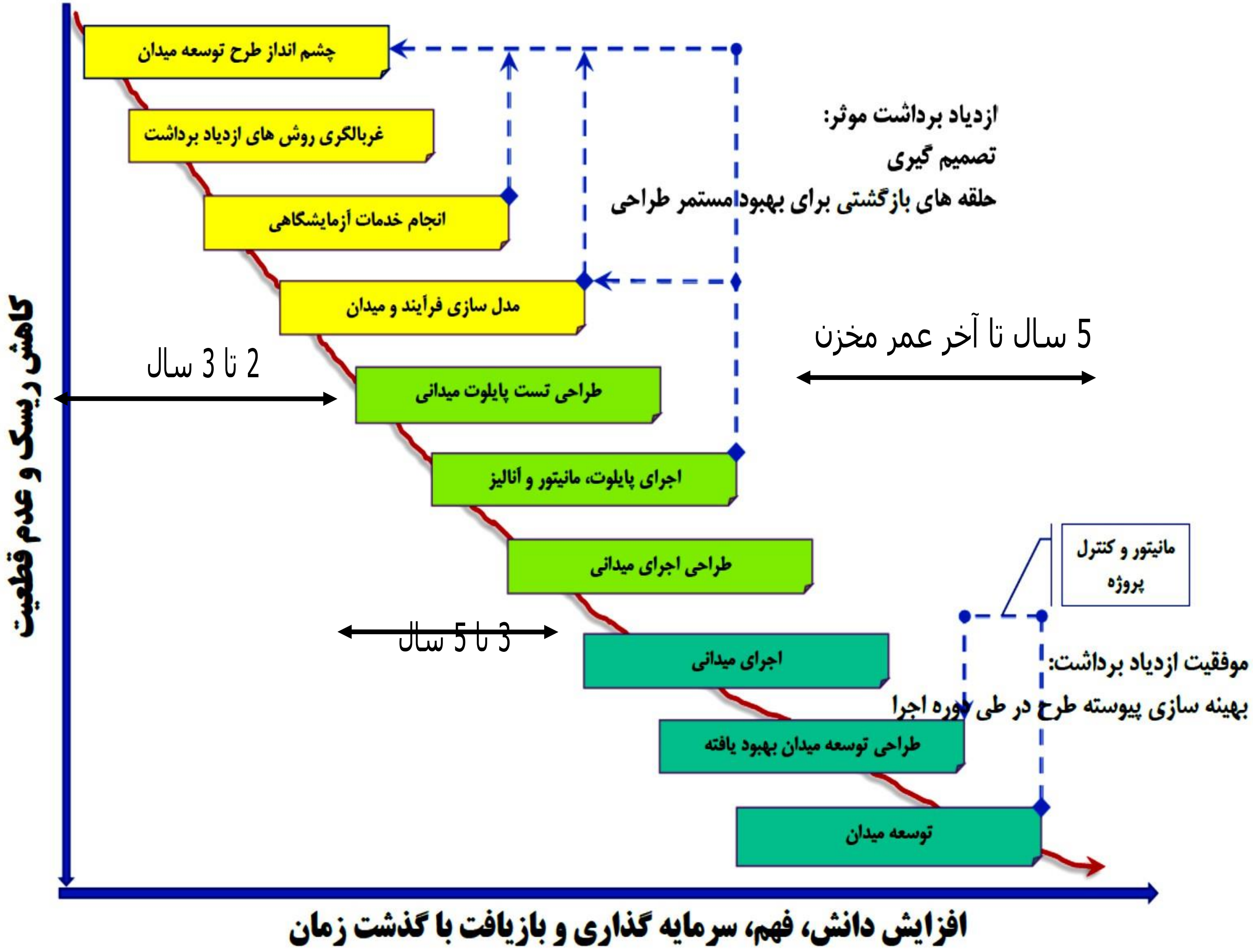
- Swelling of crude oil
- Reduction of crude oil viscosity
- Vaporization of intermediate and heavy hydrocarbons ($C_5 – C_{30}$)
- Multi-contact miscibility
- Interfacial tension lowering (miscibility)
- Internal solution gas drive.

Average Recovery Factor



EOR Road Map


Propose at field development plan stage
Screen EOR methods
– EORt* tool
Test in laboratory
– Physical and digital evaluations
Model field and process
– DeepLook-EM service
Design field pilot test
Perform pilot, monitor, and analyze
– MicroPilot* evaluation
– MiniPilot* evaluation
Fine-tune field development plan
– RSTPro* tool
– PhaseTester* equipment
Monitor and control project
– WellWatcher BriteBlue* fiber
– Flow Scanner* system
Expand field development
– Produced water treatment
– Multicomponent seismic
● Concept phase
● Pilot tests
● Full field implementation
– Key EOR technology
Efficient EOR decision making
Feedback loops to improve design are implemented rapidly.
Incremental recovery
Optimizing the EOR project continues throughout its life.
Reduce uncertainty and risk
Improve recovery


چشم انداز طرح توسعه میدان
غربالگری روش های ازدیاد برداشت
انجام خدمات آزمایشگاهی
مدل سازی فرآیند و میدان
طراحی تست پایلوت میدانی
اجرای پایلوت، مانیتور و آنالیز
طراحی اجرای میدانی
اجرای میدانی
طراحی توسعه میدان بهبود یافته
توسعه میدان
ازدیاد برداشت موثر:
تصمیم گیری
حلقه های بازگشتی برای بهبود مستمر طراحی
5 سال تا آخر عمر مخزن
2 تا 3 سال
3 تا 5 سال
مانیتور و کنترل پروژه
موفقیت ازدیاد برداشت:
بهینه سازی پیوسته طرح در طی دوره اجرا
کاهش ریسک و عدم قطعیت
افزایش دانش، فهم، سرمایه گذاری و بازیافت با گذشت زمان

Screening Criteria:

- ✓ Please read 2 Taber's papers

EOR processes:

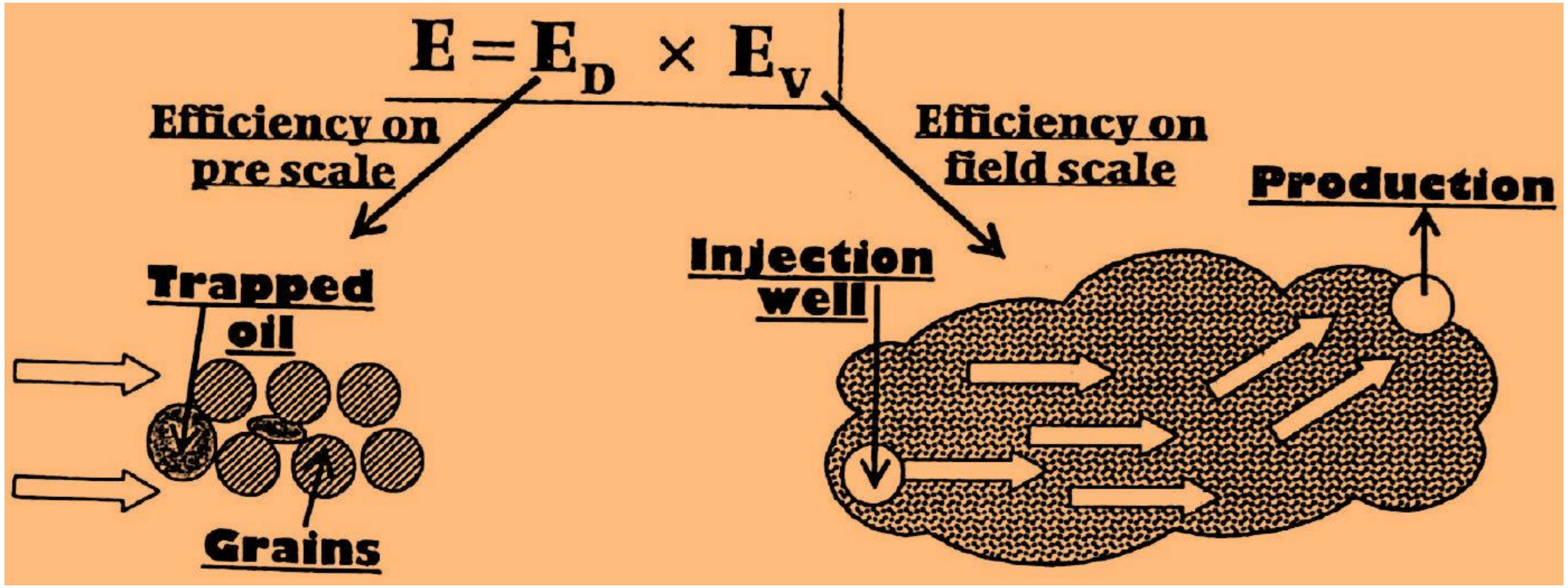
Regardless of the mechanisms involving in EOR processes, they classified into five categories:

- **Mobility control processes**
- **Chemical processes**
- **Miscible processes**
- **Thermal processes**
- **Other processes**

Idealized Characteristics of an EOR Process

Efficiency of a displacement process

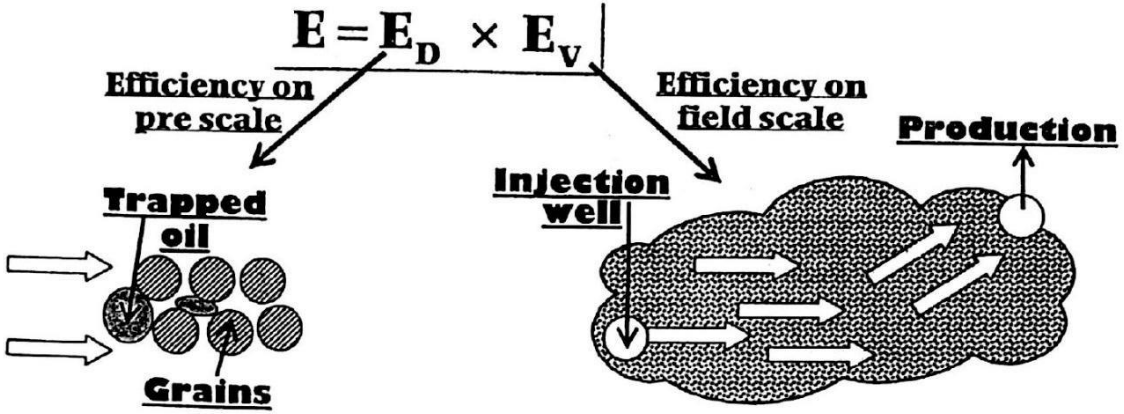
The overall displacement efficiency of any oil recovery displacement process can be considered conveniently as the product of microscopic and macroscopic displacement efficiencies:



$$E = E_D \times E_V$$

Idealized Characteristics of an EOR Process

Efficiency of a displacement process



$$E = overall\ displacement\ Eff. = \frac{oil\ recovery\ by\ the\ process}{oil\ in\ place\ at\ start\ of\ process}$$

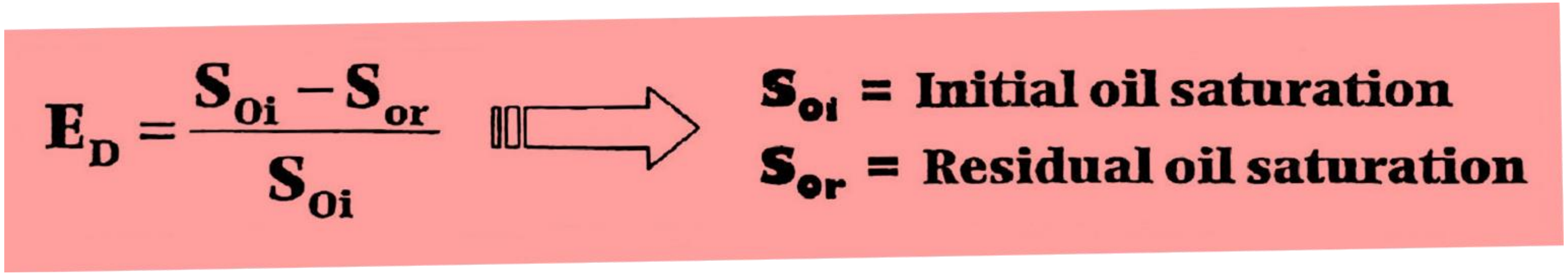
$E_D = Microscopic\ displacement\ efficiency, expressed\ as\ fraction$

$E_V = Macroscopic\ or\ volumetric\ displacement\ efficiency, expressed\ as\ fraction$

Idealized Characteristics of an EOR Process

Microscopic displacement, E_D

Microscopic displacement relates to the displacement or mobilization of oil at the pore scale. That is a measure of the effectiveness of the displacing fluid in moving (mobilizing) the oil at those places in the rock where the displacing fluid contacts the oil. It is reflected in the magnitude of the residual oil saturation in the regions contacted by the displacing fluid. It is generally defined as:



$$E_D = \frac{S_{Oi} - S_{or}}{S_{Oi}} \Longrightarrow$$

S_{oi} = Initial oil saturation

S_{or} = Residual oil saturation

Idealized Characteristics of an EOR Process

Microscopic displacement, E_D

Example:

In a typical water flooding which initial oil saturation is 0.6 and residual oil saturation in the swept regions is 0.3. the microscopic displacement efficiency is:

$$E_D = \frac{0.6-0.3}{0.6} = 0.5$$

Idealized Characteristics of an EOR Process

Macroscopic or volumetric displacement, E_V

It is a measure of how effectively the displacing fluid sweeps out the volume of a reservoir, both areally and vertically, as well as how effectively the displacing fluid moves the displaced oil toward production wells.

Both areal and vertical sweeps must be considered. It is often useful to further subdivide EV into the product of areal and vertical displacement:

$$E_V = E_S \times E_I$$

E_S= Areal swept efficiency

E_I= Vertical swept efficiency

Idealized Characteristics of an EOR Process

Areal displacement Efficiency, E_S

The area of sweeps by displacement fluids increases with time, but it never becomes equal to the area of the reservoir, even long after the initial breakthrough of the front at the production well.

Always remains certain “dead zones” not swept by the displacing fluid. For this reason, the areal sweep efficiency is defined as:

$$E_S = \frac{\text{Swept area, W}}{\text{Reservoir area}}$$

Idealized Characteristics of an EOR Process

If vertical heterogeneity is negligible:

$$\mathbf{E_v = E_s \times h \cdot \phi \cdot S}$$

h= Reservoir thickness

Ø= Porosity

S = gas or oil saturation

In the case of constant thickness, porosity and saturation, we have

$$\mathbf{E_v = E_s}$$

Idealized Characteristics of an EOR Process

If vertical heterogeneity is not negligible:

When there are vertical heterogeneities within the volume swept, some zones will not be invaded by the displacing fluid. This can be accounted for by using an invasion efficiency, E_I, of less than unity. E_I is also known as the vertical sweep efficiency.

$$\mathbf{E_V = E_S \times E_I}$$

For water flooding, typical E_V is 0.7 and therefore, the overall efficiency becomes:

$$\mathbf{E = E_V \times E_D = 0.7 \times 0.5 = 0.35!}$$

Idealized EOR process

Therefore an idealized EOR process would be one in which the displacing fluid remove all oil from the pores contacted by the fluid. Hence:

$$S_{or} \rightarrow 0 \Longrightarrow E_D \rightarrow 1$$

And in which the displacing fluid contacts the total reservoir volume and displaces oil to the production well

$$W \rightarrow \text{Reservoir area} \Longrightarrow E_V \rightarrow 1$$

Parameters affecting microscopic displacement efficiency, E_D

- **Miscibility between the fluids**
- **Reduction of IFT between the fluids**
- **Oil volume expansion (swelling) as a result of diffusion and dispersion between phases**
- **Oil viscosity reduction**
- **Favorable mobility ratio between the displaced and displacing fluid**

Parameters affecting macroscopic (volumetric) displacement efficiency, E_V

The Ratios of Sweeping aerial/ Reservoir areal and vertical Sweeping / Reservoir height

- **Maintenance of favorable density difference between the displacing and displaced fluids**
  - ✓ Large density differences can result in gravity segregation which result in underriding or overriding of the fluid being displaced. The net effect is to bypass fluid at the top or bottom of reservoir and so reducing E_V
- **Reservoir geology and in particular geologic heterogeneity is an important factor in consideration of macroscopic displacement efficiency**
- **The influence of reservoir characteristics**
  - ✓ Average depth
  - ✓ Structure, in particular the dip of the bed
  - ✓ Degree of homogeneity
  - ✓ Petrophysical properties including, permeability, capillary pressure, wettability, thermal conductivity, etc.

Microscopic displacement of fluids in a reservoir

As discussed before, microscopic displacement efficiency depends on the magnitude of the residual oil saturation.

On the other hand, the residual oil saturation itself depends on:

- **Phase trapping**
- **Phase mobilizing**

Oil trapping and mobilizing are also governed by:

- ✓ **Capillary forces:** results of surface and interfacial forces
- ✓ **Viscous forces**

Capillary forces

Fluid distribution in porous media are affected by:

- **Forces at fluid/fluid interfaces**: surface tension and IFT
- **Forces at fluid/solid interfaces**: wettability

Surface and interfacial tensions:

The net surface forces between two immiscible phases is quantified in terms of surface tension. Surface tension is related to the energy required to create new surface area or:

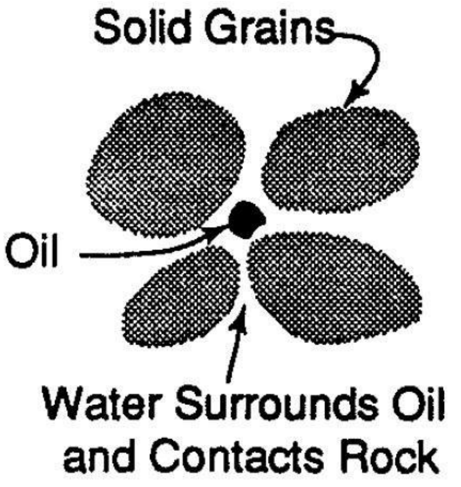
$$\sigma = \frac{W}{A} = \frac{N \cdot m}{m^2} \qquad \frac{N}{m}$$

Capillary forces

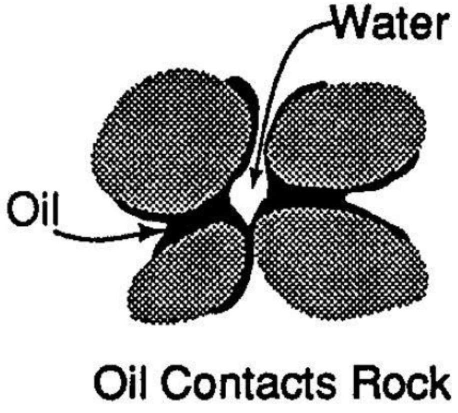
Wettability

Wettability is the tendency of one fluid to spread on or adhere to a solid in the presence of a second fluid.

Rock wettability affects the nature of fluid saturations and the general relative permeability characteristics of fluid/rock system



Water-Wet System

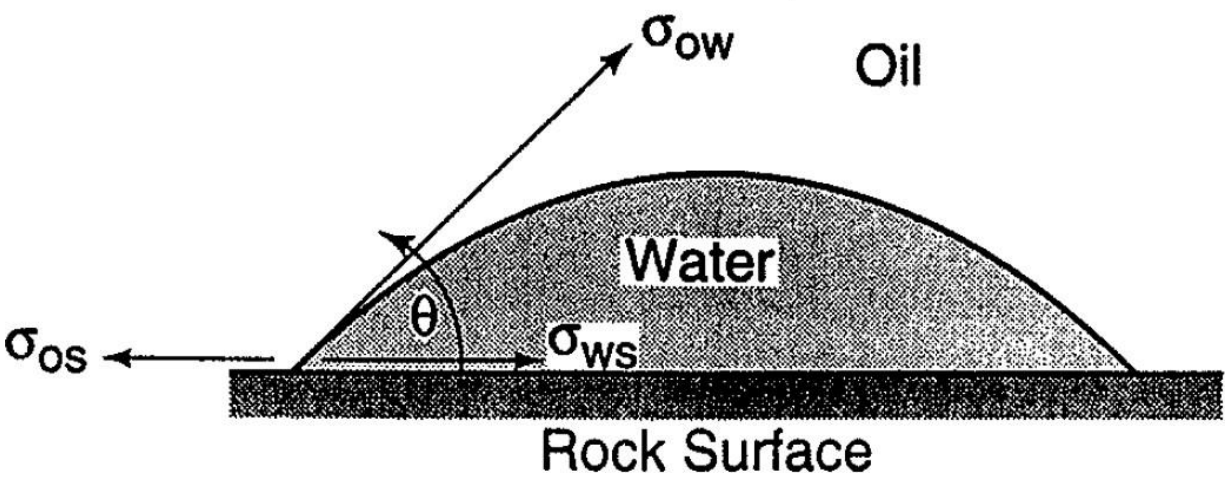


Oil -Wet System

Capillary forces

Wettability

Wettability can be quantified by examining the interfacial forces which exist when oil and water are in contact with solid rock by Young's equation



$$\sigma_{os} - \sigma_{ws} = \sigma_{ow} \cos \theta$$

Capillary forces

Wettability

While σ_{ow} can be measured, σ_{os} and σ_{ws} have never been measured yet directly. Experimental methods have not developed yet to make these determinations. Therefore, contact angle is used to measure wettability.

- ✓ **$\theta < 90$ the rock is considered water wet**
- ✓ **$\theta > 90$ the rock is considered oil wet**

$\theta = 0$, strong water-wet $\theta = 180$, strong Oil-wet $\theta = 90$, intermediate or mixed wet

Capillary forces

Capillary pressure

IFT (σ) and wettability (θ) are related to capillary pressure. Because the interfaces are in tension, a pressure difference exists across the interface. This pressure is called capillary pressure.

Force balance: $2\pi r.\cos\theta.\ \sigma=\pi r^2.\ (\rho_w - \rho_o).h.g$

$$P_c = P_o - P_w = (\rho_o - \rho_w)hg = \frac{2\sigma_{ow}\cos\theta}{r}$$

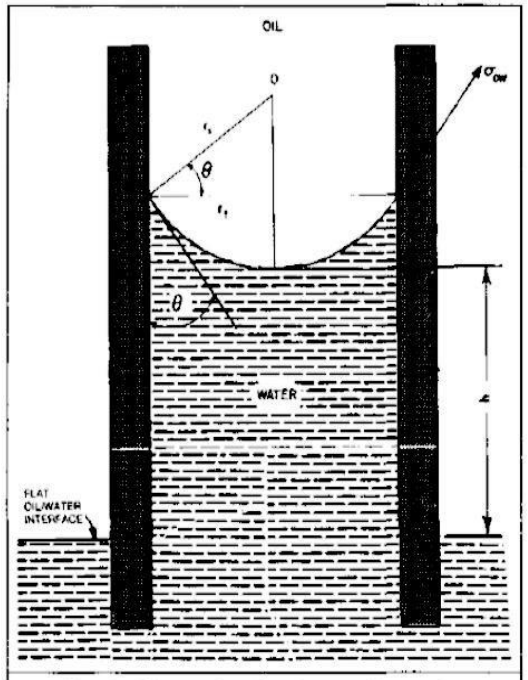


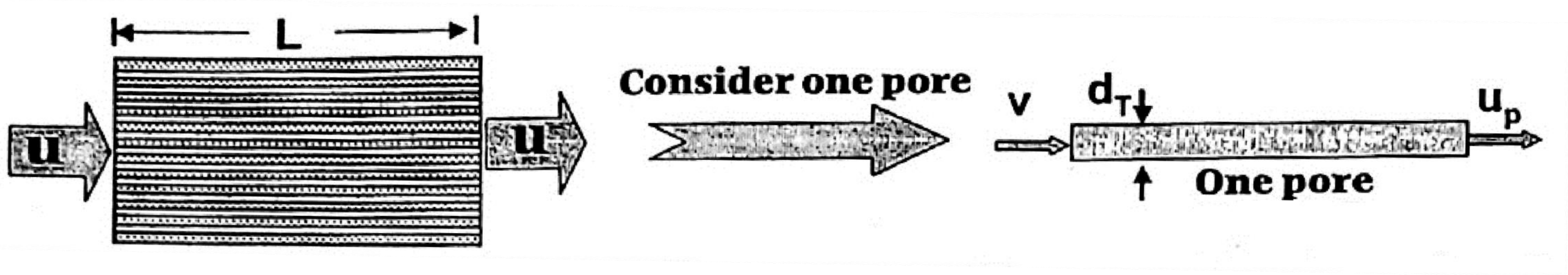
Fig. 1—Oil/water interface in a capillary tube.

Capillary forces

Viscous forces

Viscous forces in a porous medium are reflected in the magnitude of the pressure drop that occurs as a result of flow of fluid through the medium(pores).

The pressure drop in a single pore is given by Poiseuille’s law in capillary pore model



Capillary forces

Viscous forces

The viscous forces in a single pore is given by the Poiseuille's law:

$$\Delta P = -\frac{8\mu L}{r^2} \cdot v$$

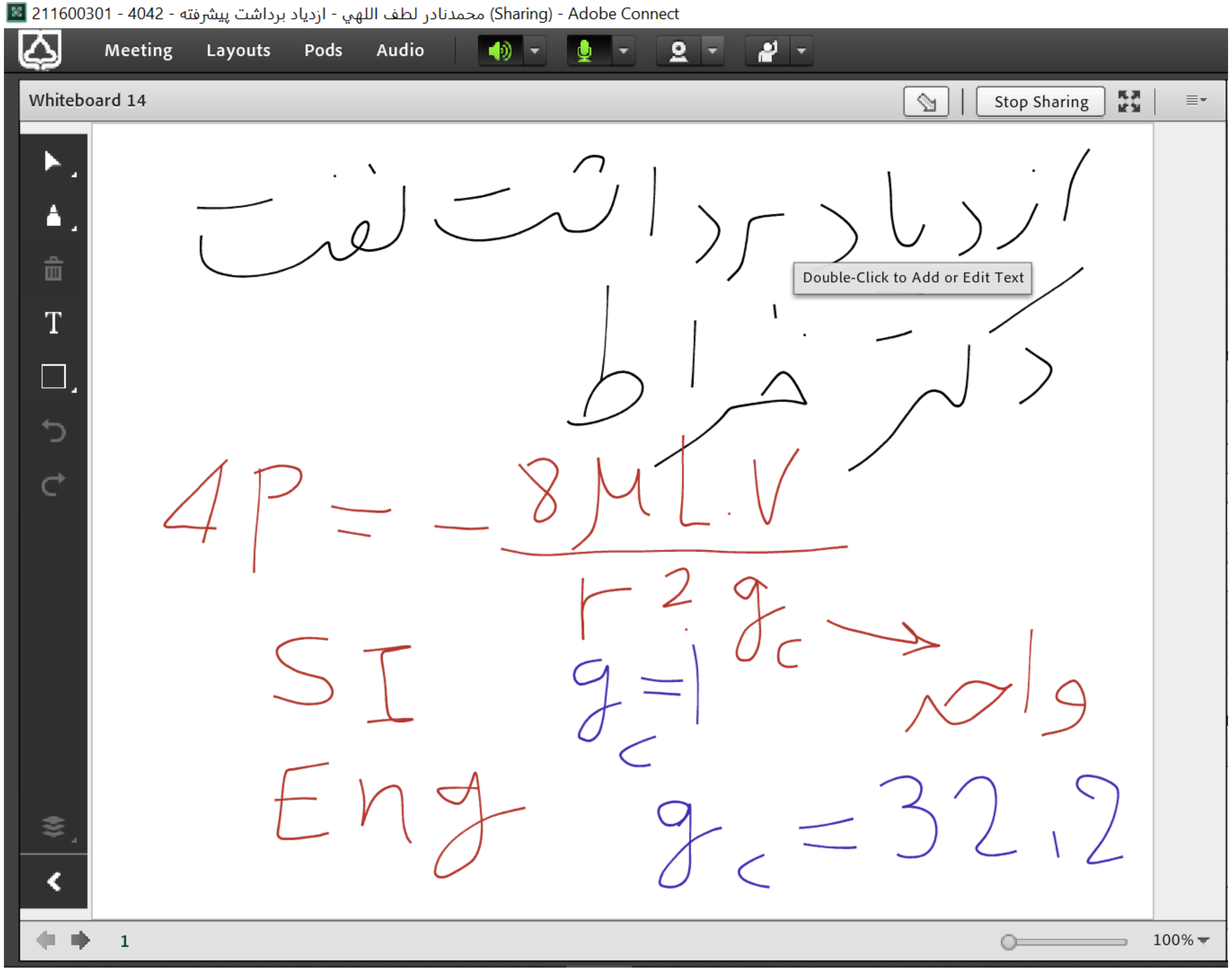
Therefore, in the absence of gravity, the net forces which try to displace oil from the pore is equal to:

$$\Delta P = -\frac{8\mu L}{r^2} \cdot v + \frac{2\sigma \cos\theta}{r}$$

$\Delta p/\rho g=f.L/D.v2/2g$

$F=64/Re=64\mu/\rho vD$

$\Delta p/\rho g=64\mu/\rho vD.L/D.v2/2g= 8\ \mu L/r^2.(v)/\ \rho g$



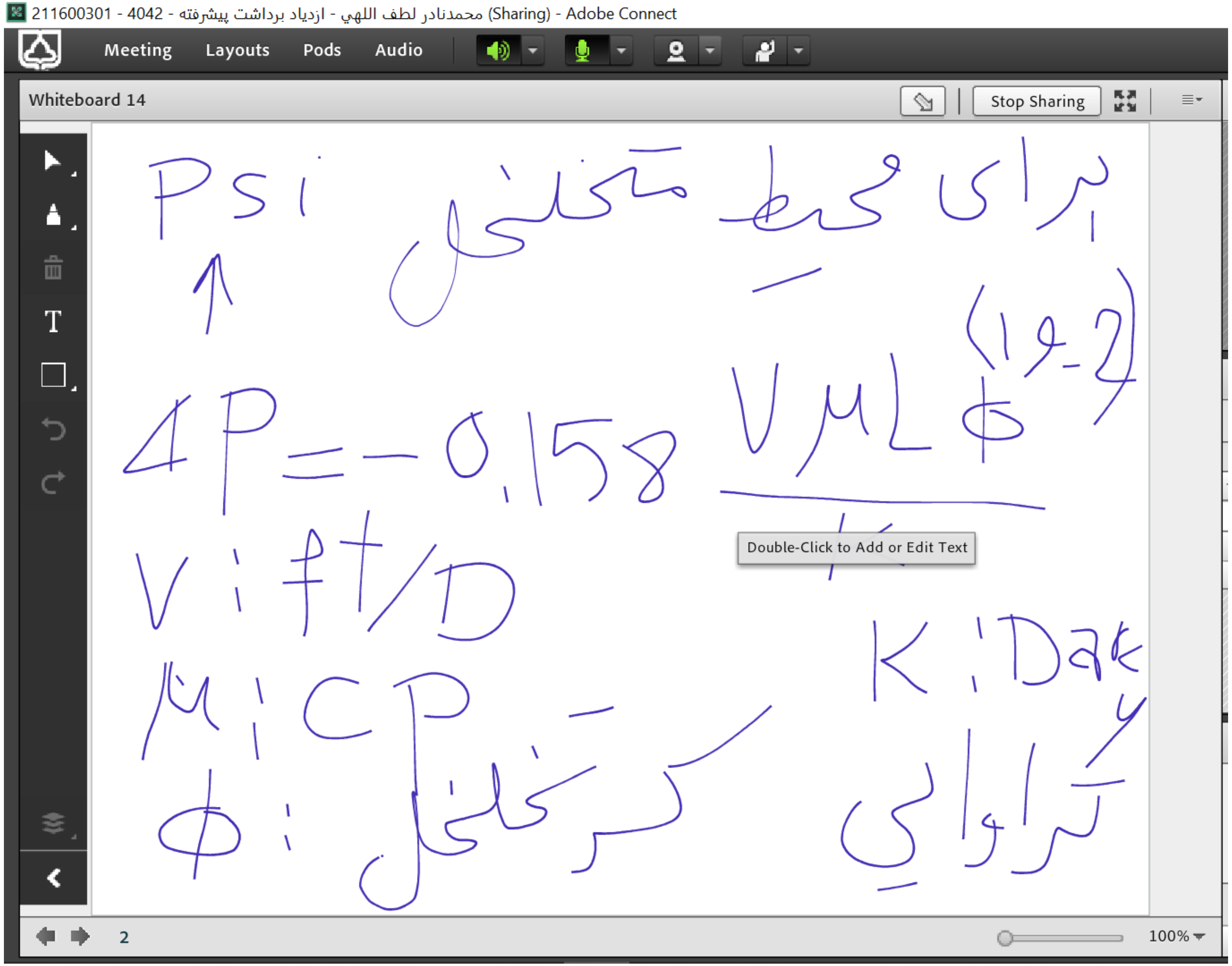
ازدیاد برداشت نفت

دکتر خراط

$$\Delta P = \frac{8 \mu L V}{r^2 g_c}$$

SI $g_c = 1$ → واحد

Eng $g_c = 32.2$



برای محیط متخلخل

Psi ↑

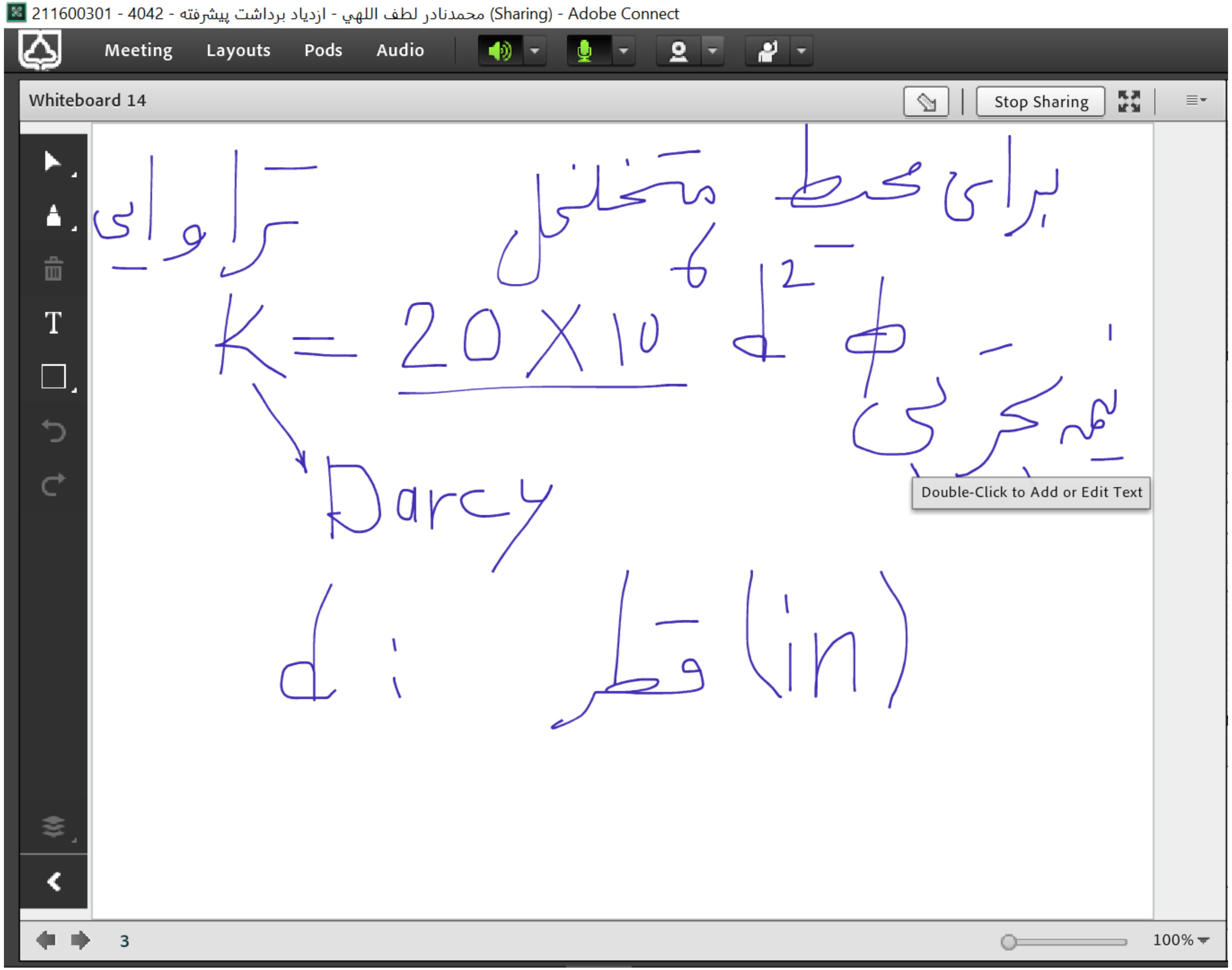
$$\Delta P = -0.158 \frac{V \mu L \phi^{(19-2)}}{k}$$

V : ft/D

μ : cp

φ : تخلخل

K : Dak ↙ تراوایی

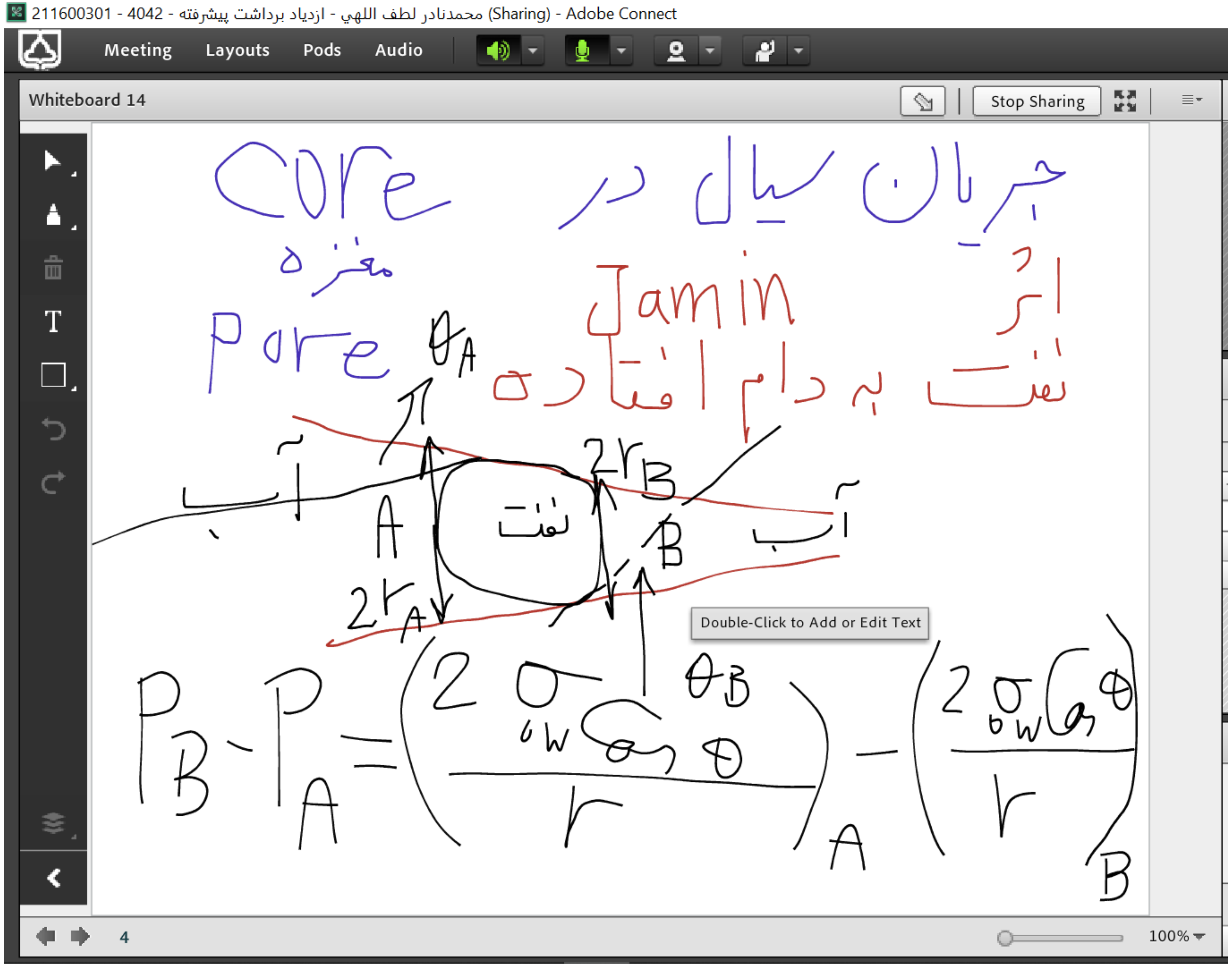


تراوایی برای محیط متخلخل

$K = \underline{20 \times 10^{6}} d^{2} \phi$ [illegible]

K → Darcy

d : قطر (in)



جریان سیال در Core

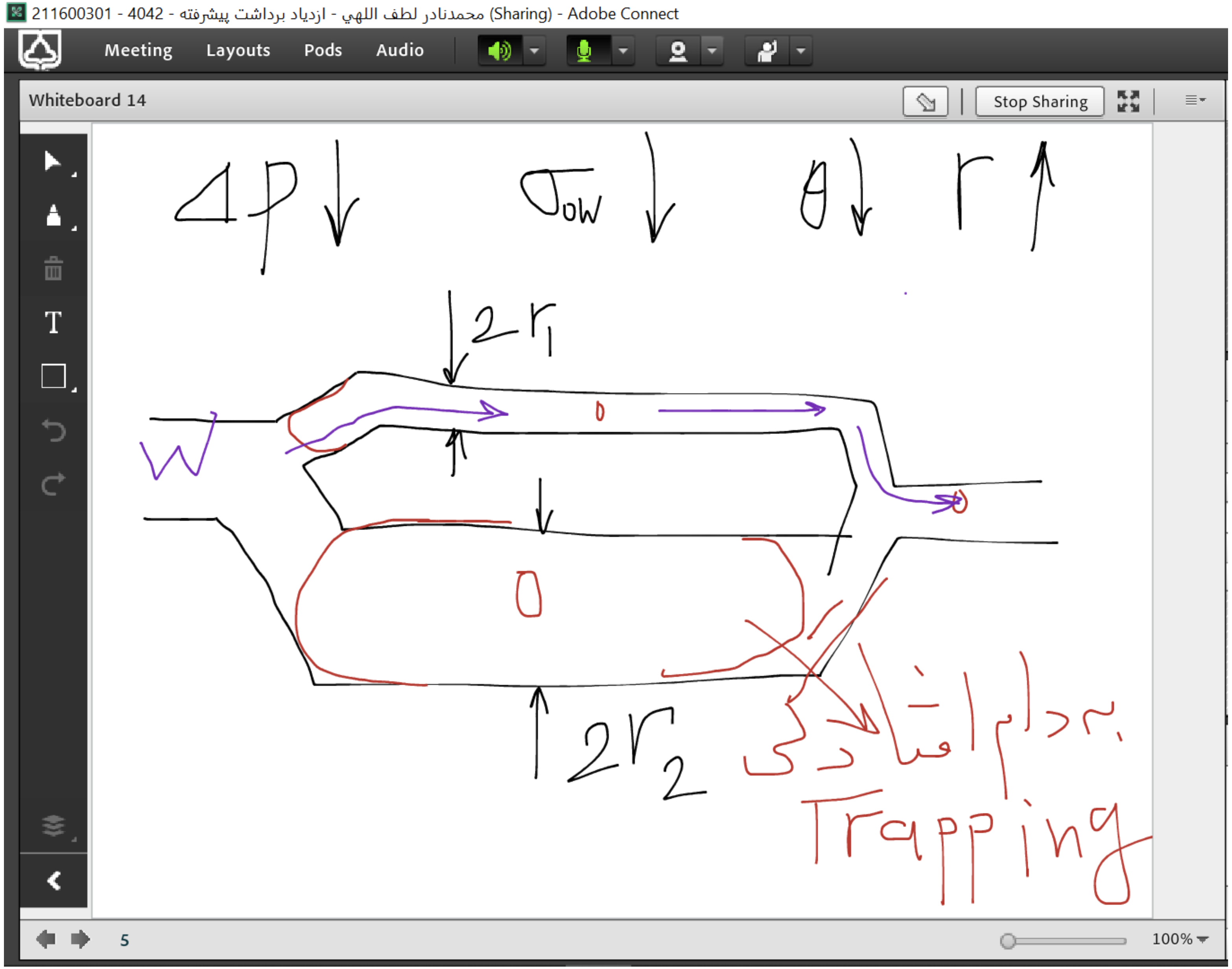
مغزه

Pore

اثر Jamin

نفت به دام افتاده

$$P_B - P_A = \left(\frac{2\sigma_{ow}\cos\theta}{r}\right)_A - \left(\frac{2\sigma_{ow}\cos\theta}{r}\right)_B$$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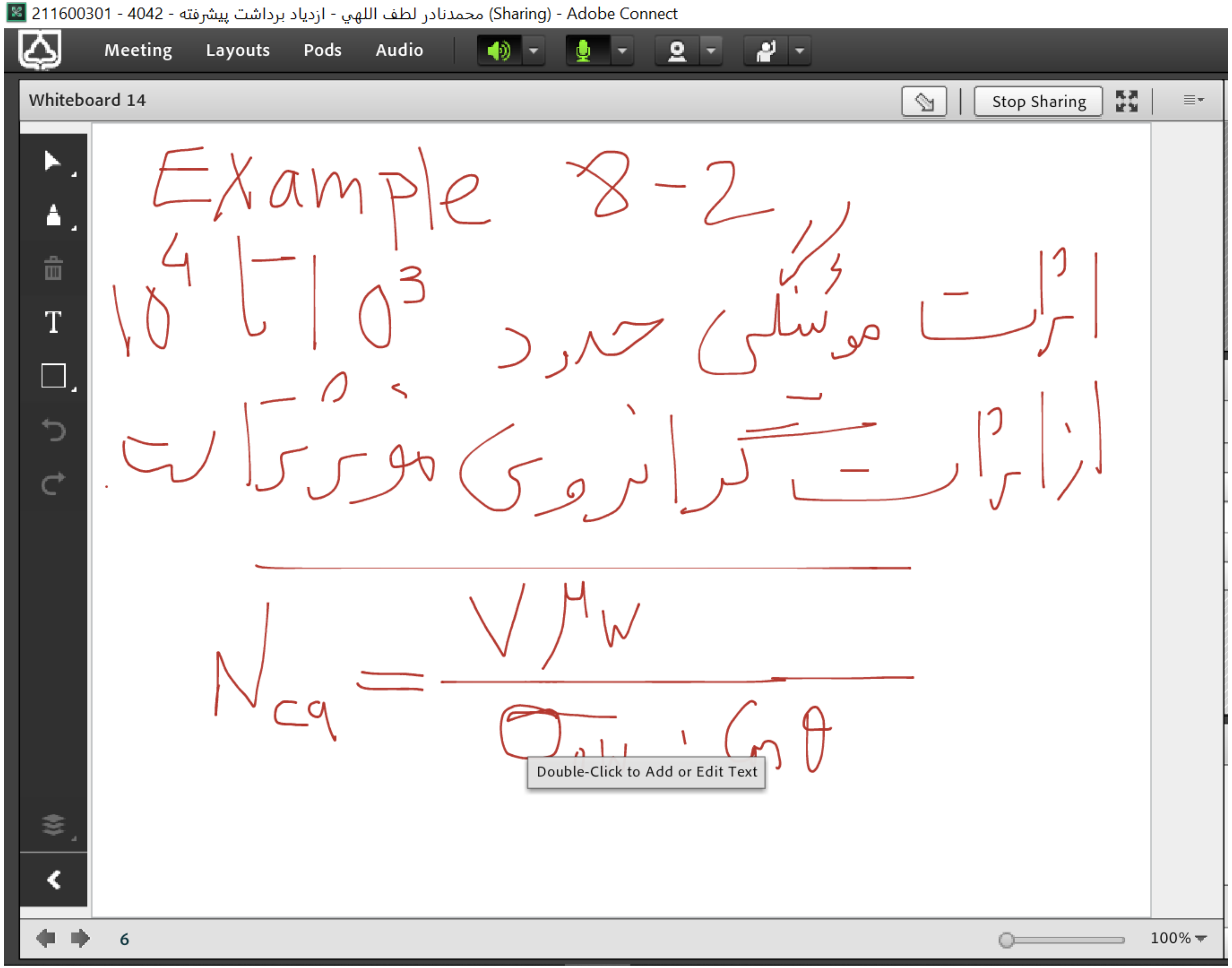
Meeting
Layouts
Pods
Audio
Whiteboard 14
Stop Sharing
5
100%
ΔP ↓
σow ↓
θ ↓
r ↑
2r1
W
o
o
o
2r2
به دام افتادگی
Trapping



Example 8-2

اثرات موئینگی حدود 10^3 تا 10^4

از اثرات گرانروی مؤثرتر است

$$N_{ca} = \frac{V \mu_w}{\sigma_{ow} \cos\theta}$$

Capillary number

$Nca=8\ \mu L/r^2.(v)./2.\cos\theta.\ \sigma\ /r$

The importance of viscous and capillary forces in any displacement process can easily been shown by the defining a dimensionless capillary number

$$N_{Ca} = \frac{\text{Viscous forces}}{\text{Capillary forces}} = \frac{8L\mu v}{2\sigma r\cos\theta} \approx \frac{\mu_w v}{\sigma\cos\theta}$$

Other forms of capillary number that can be seen in the literature are:

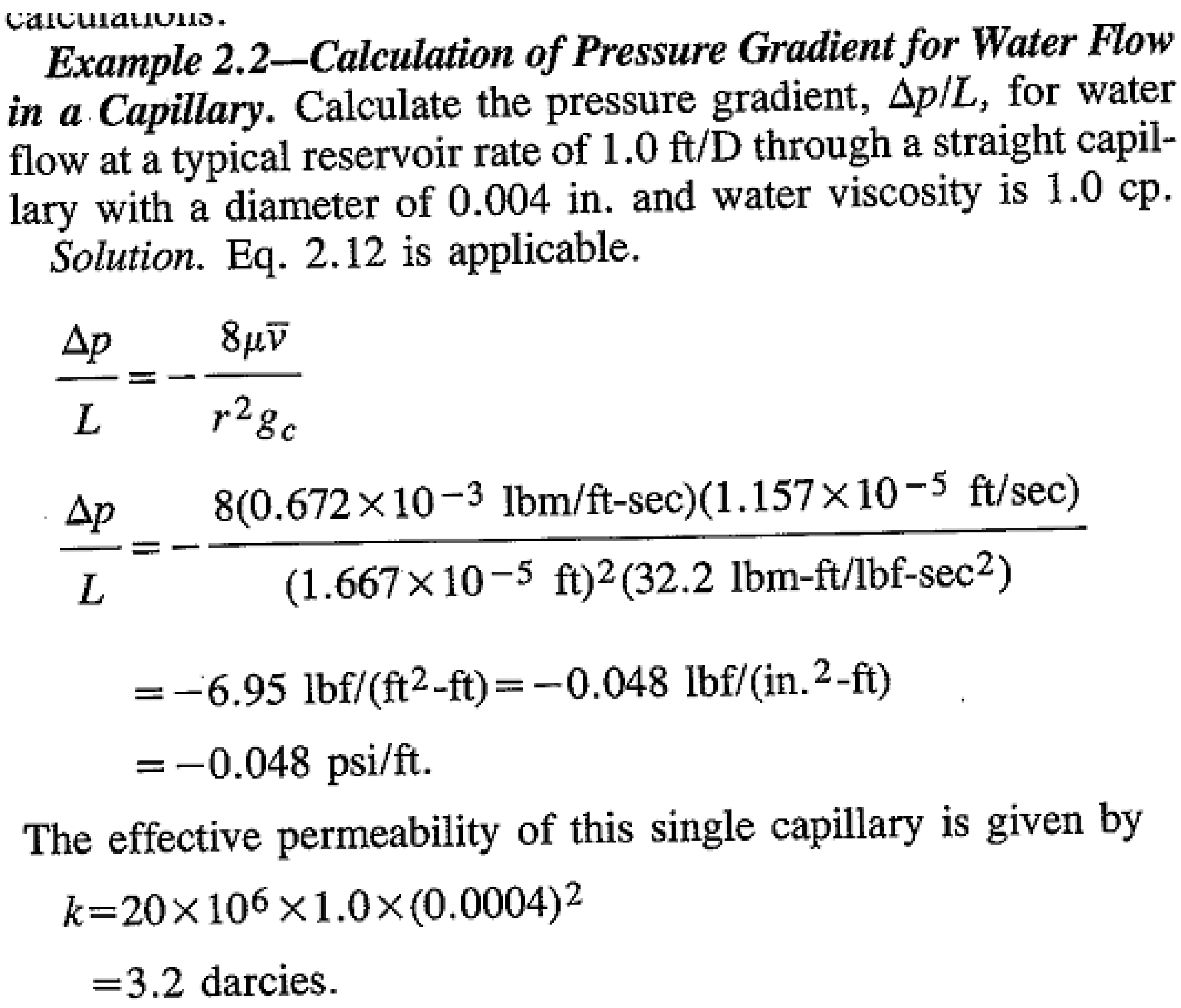
Capillary forces

Capillary number

The definition shows that as capillary number increases, the residual oil saturation decreases and, therefore, microscopic displacement efficiency increases.

Capillary number can be increased by:

- ☐ **Increasing water viscosity**
- ☐ **Decreasing interfacial tension between water and oil**
- ☐ **Increasing water injection rate**



calculations.

Example 2.2—Calculation of Pressure Gradient for Water Flow in a Capillary. Calculate the pressure gradient, $\Delta p/L$, for water flow at a typical reservoir rate of 1.0 ft/D through a straight capillary with a diameter of 0.004 in. and water viscosity is 1.0 cp.

Solution. Eq. 2.12 is applicable.

$$\frac{\Delta p}{L} = -\frac{8\mu\bar{v}}{r^2 g_c}$$

$$\frac{\Delta p}{L} = -\frac{8(0.672\times10^{-3}\ \text{lbm/ft-sec})(1.157\times10^{-5}\ \text{ft/sec})}{(1.667\times10^{-5}\ \text{ft})^2(32.2\ \text{lbm-ft/lbf-sec}^2)}$$

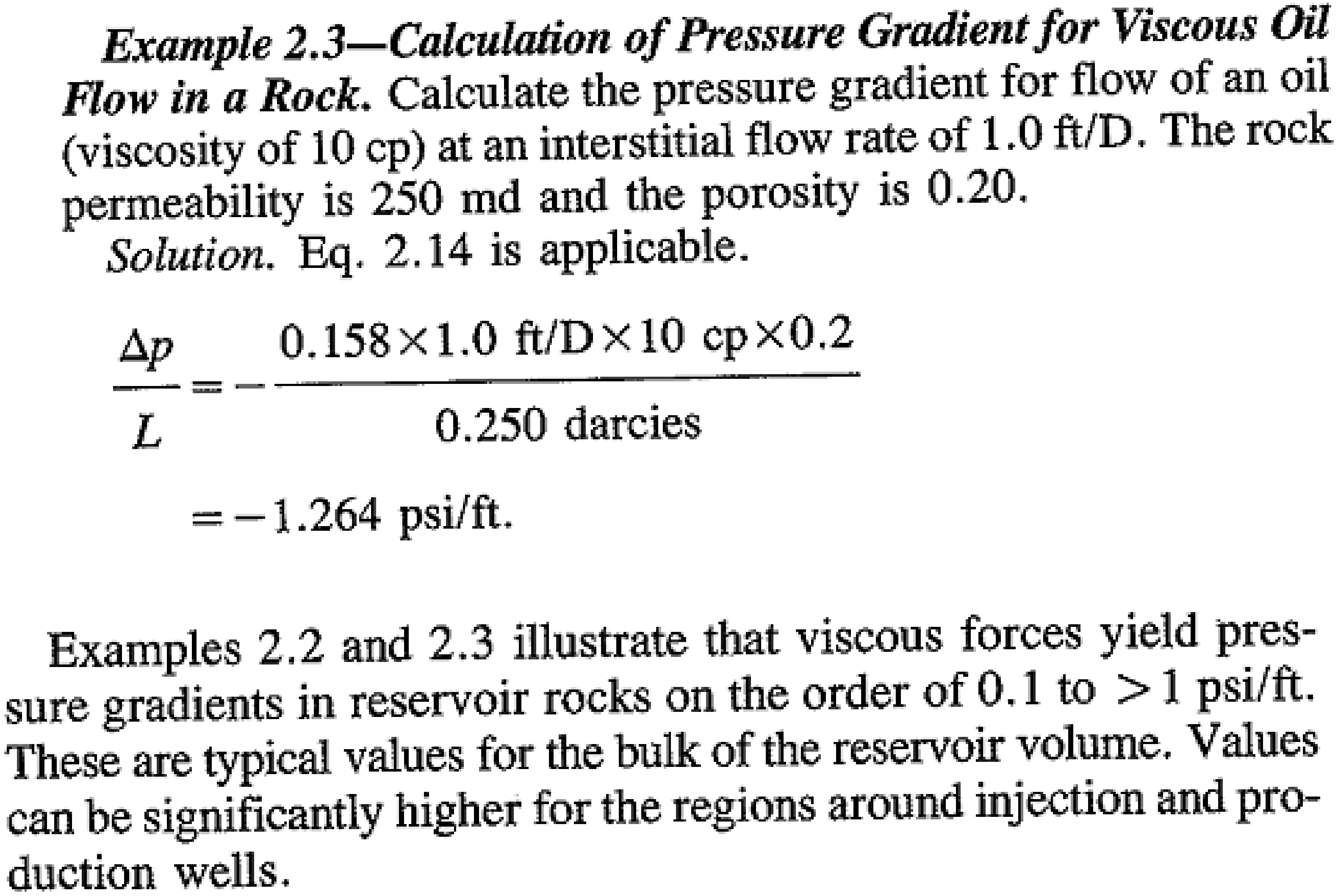
$$= -6.95\ \text{lbf/(ft}^2\text{-ft)} = -0.048\ \text{lbf/(in.}^2\text{-ft)}$$

$$= -0.048\ \text{psi/ft.}$$

The effective permeability of this single capillary is given by

$$k = 20\times10^6\times1.0\times(0.0004)^2$$

$$= 3.2\ \text{darcies.}$$



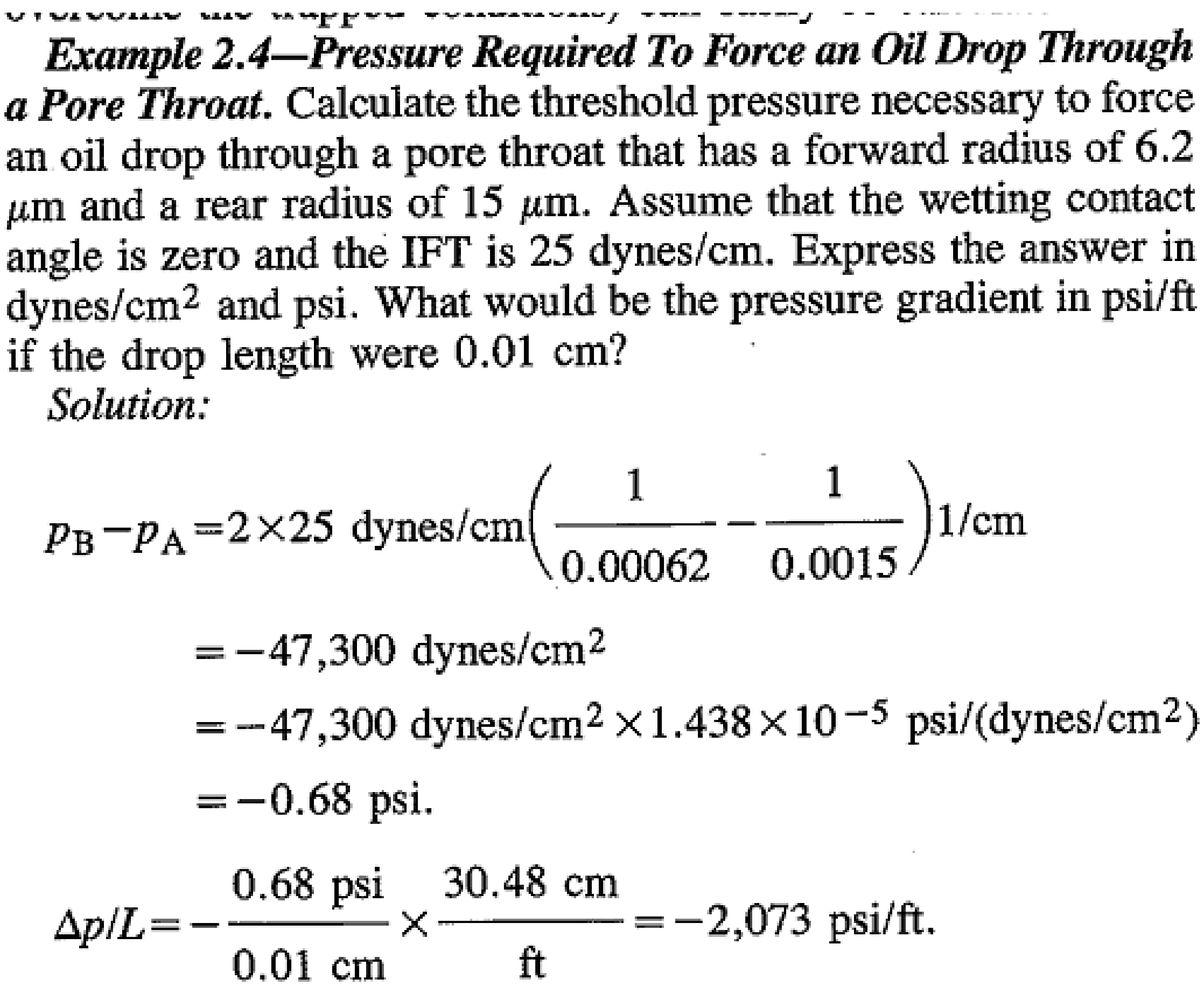
Example 2.3—Calculation of Pressure Gradient for Viscous Oil Flow in a Rock. Calculate the pressure gradient for flow of an oil (viscosity of 10 cp) at an interstitial flow rate of 1.0 ft/D. The rock permeability is 250 md and the porosity is 0.20.

Solution. Eq. 2.14 is applicable.

$$\frac{\Delta p}{L} = -\frac{0.158 \times 1.0 \text{ ft/D} \times 10 \text{ cp} \times 0.2}{0.250 \text{ darcies}}$$

$$= -1.264 \text{ psi/ft.}$$

Examples 2.2 and 2.3 illustrate that viscous forces yield pressure gradients in reservoir rocks on the order of 0.1 to >1 psi/ft. These are typical values for the bulk of the reservoir volume. Values can be significantly higher for the regions around injection and production wells.



Example 2.4—Pressure Required To Force an Oil Drop Through a Pore Throat. Calculate the threshold pressure necessary to force an oil drop through a pore throat that has a forward radius of 6.2 μm and a rear radius of 15 μm. Assume that the wetting contact angle is zero and the IFT is 25 dynes/cm. Express the answer in dynes/cm^2 and psi. What would be the pressure gradient in psi/ft if the drop length were 0.01 cm?

Solution:

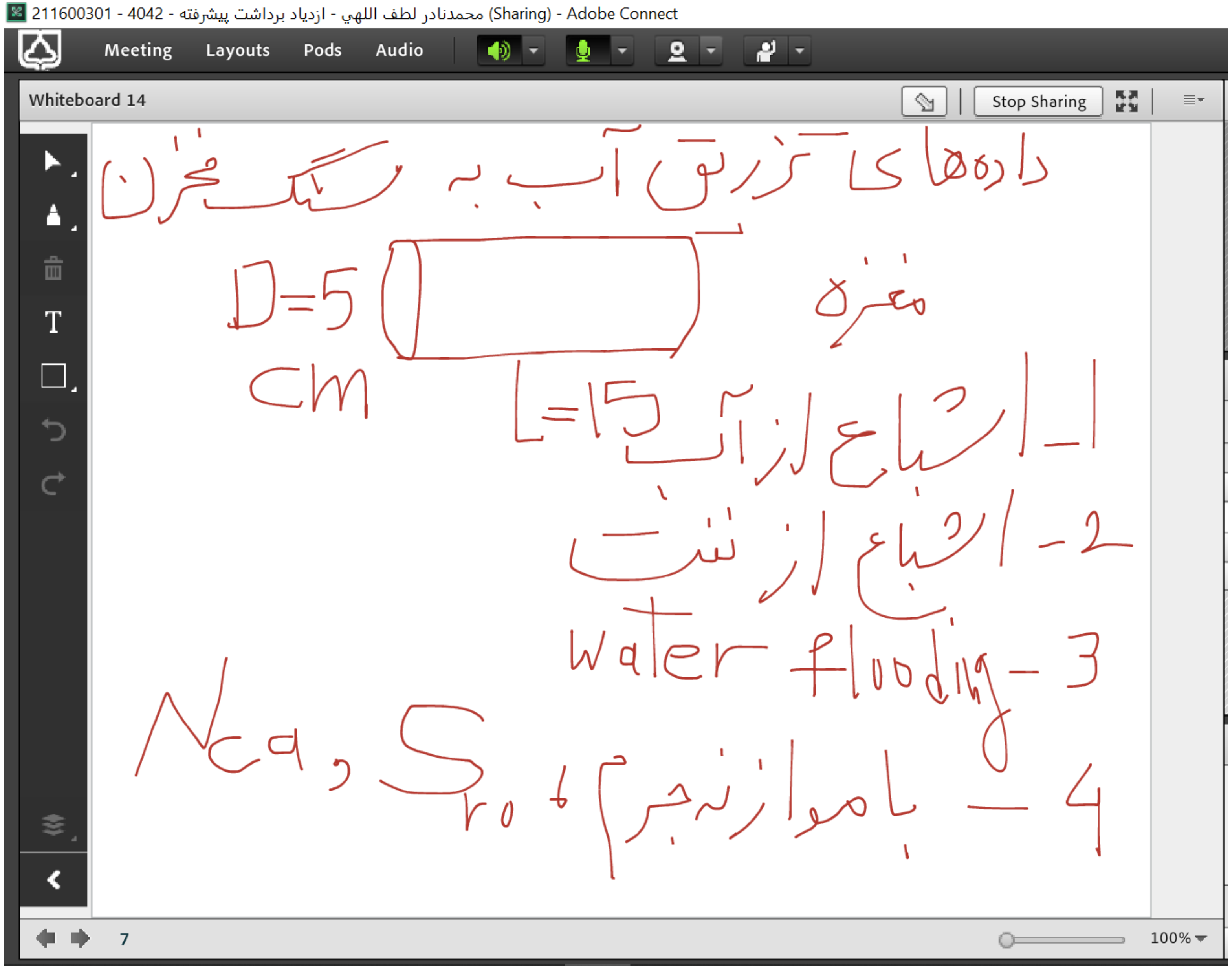
$$p_B - p_A = 2 \times 25 \text{ dynes/cm} \left(\frac{1}{0.00062} - \frac{1}{0.0015} \right) 1/\text{cm}$$

$$= -47{,}300 \text{ dynes/cm}^2$$

$$= -47{,}300 \text{ dynes/cm}^2 \times 1.438 \times 10^{-5} \text{ psi/(dynes/cm}^2)$$

$$= -0.68 \text{ psi.}$$

$$\Delta p / L = -\frac{0.68 \text{ psi}}{0.01 \text{ cm}} \times \frac{30.48 \text{ cm}}{\text{ft}} = -2{,}073 \text{ psi/ft.}$$



داده‌های تزریق آب به سنگ مخزن

مغزه

D=5 cm

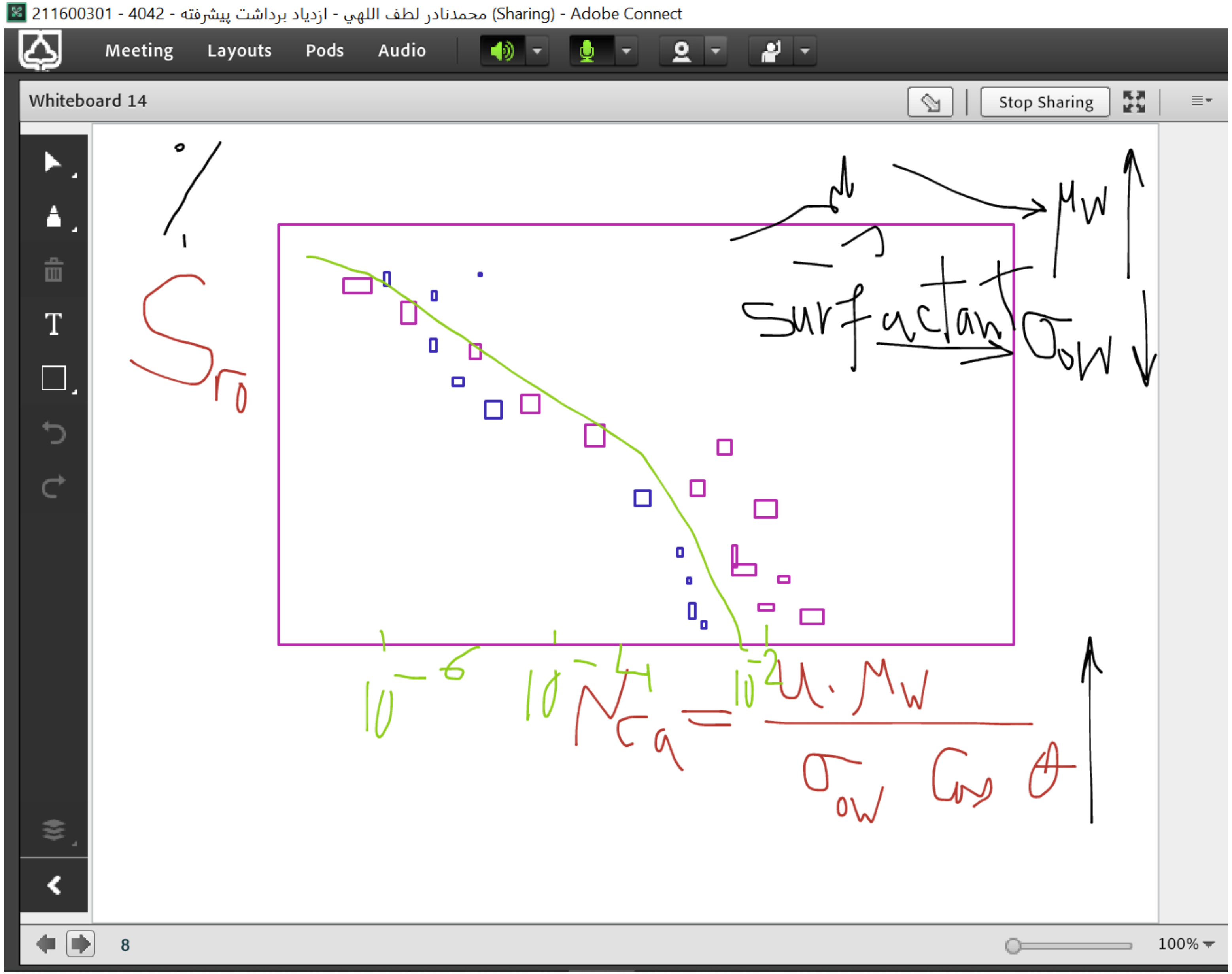
L=15

1- اشباع از آب

2- اشباع از نفت

3- water flooding

4- با موازنه جرم N_{ca} , S_{ro}



$$N_{ca} = \frac{u \cdot \mu_w}{\sigma_{ow} \cos\theta}$$

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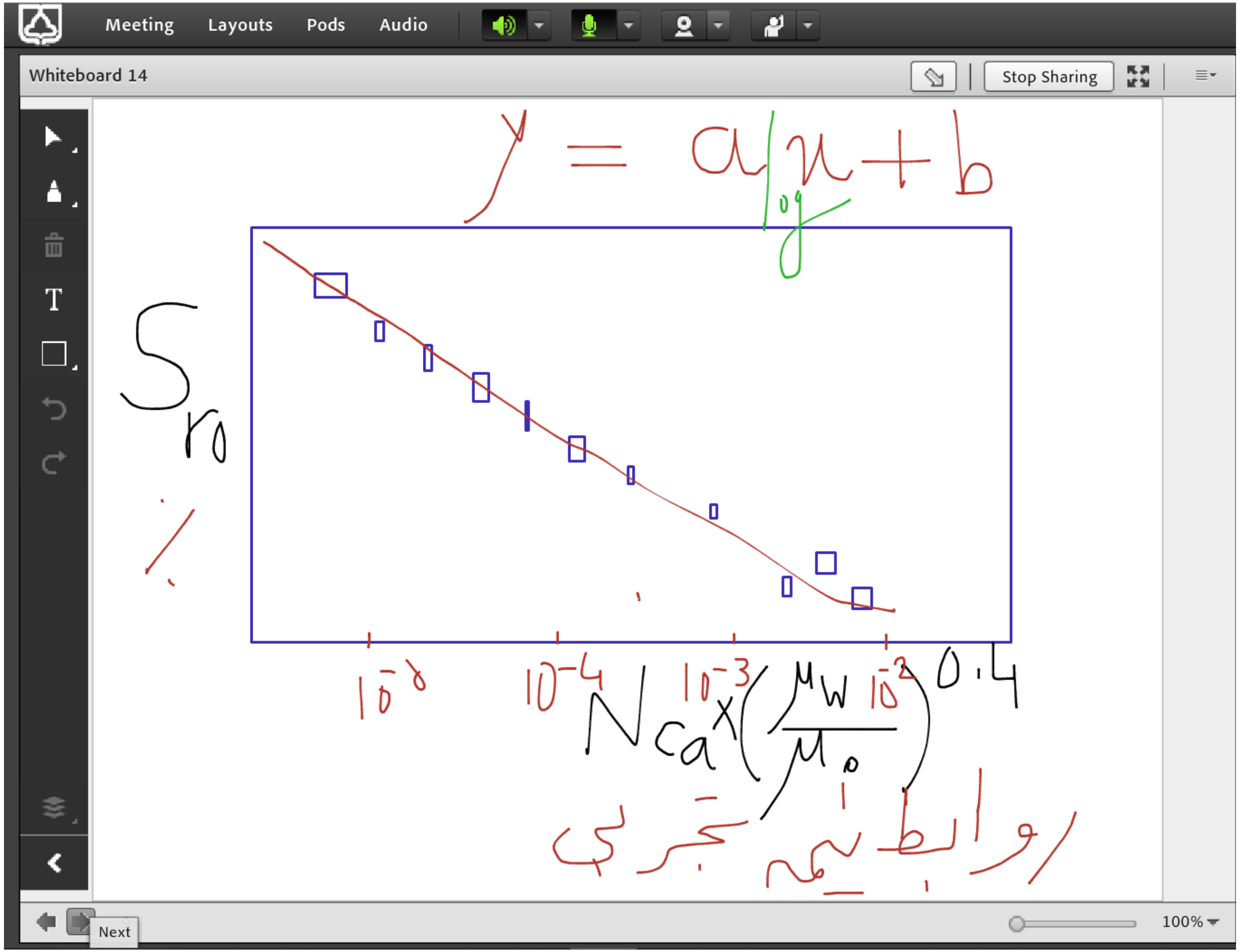
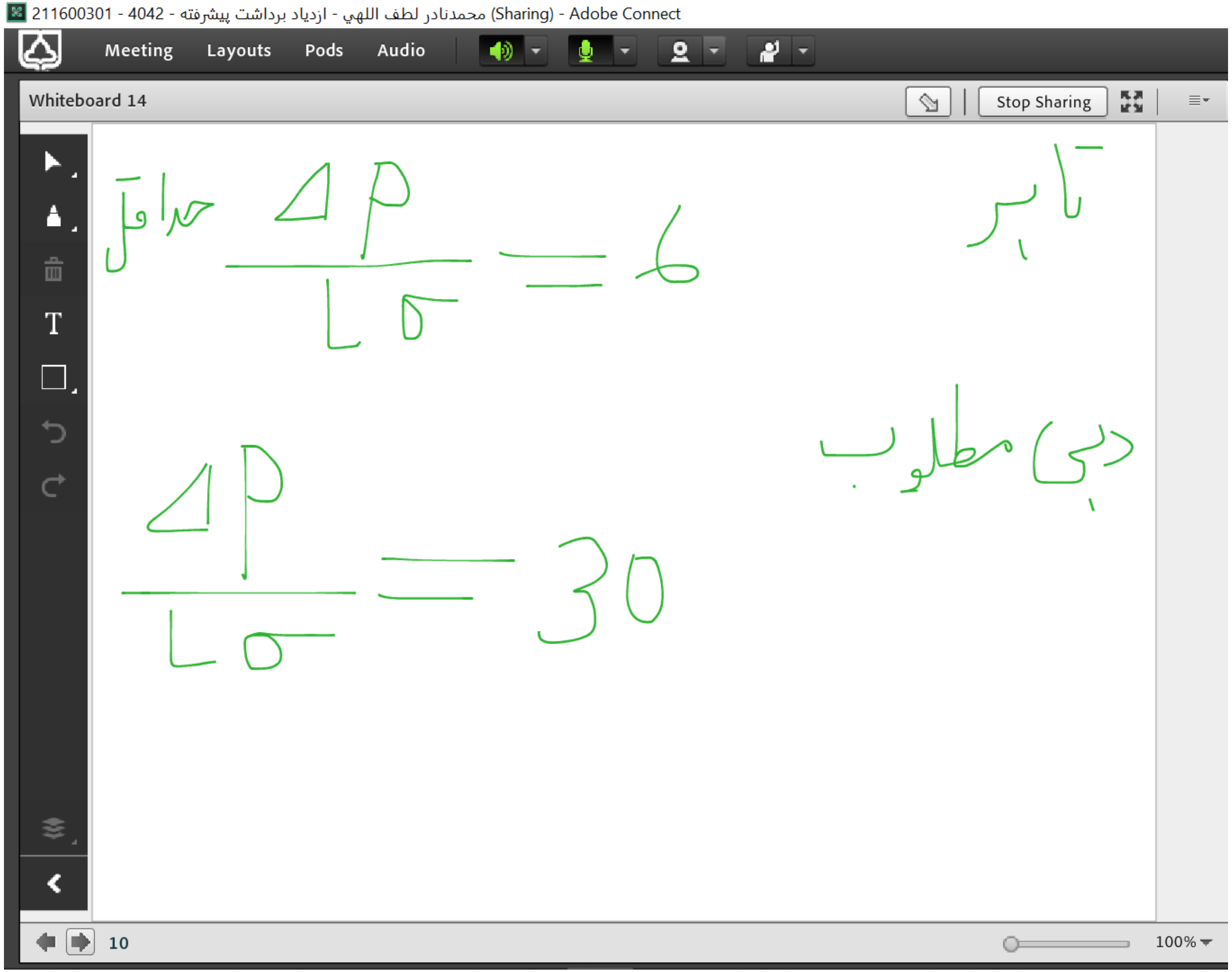


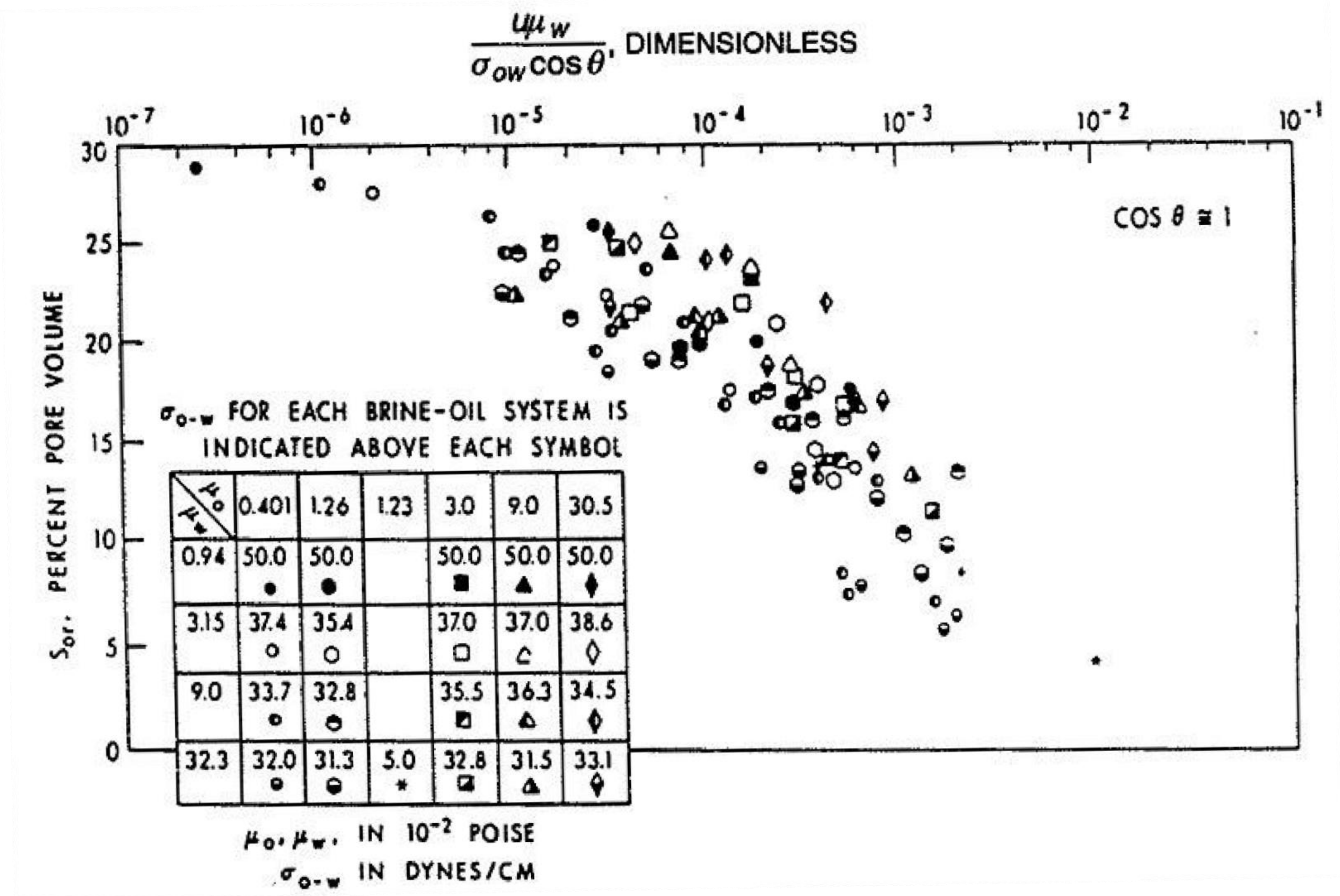


حداقل $\frac{\Delta P}{L\sigma} = 6$ تا بر

$\frac{\Delta P}{L\sigma} = 30$ دبی مطلوب

Capillary forces

Experimental observations



$\sigma_{o\text{-}w}$ FOR EACH BRINE-OIL SYSTEM IS INDICATED ABOVE EACH SYMBOL

μ_w \ μ_o	0.401	1.26	1.23	3.0	9.0	30.5
0.94	50.0 ●	50.0 ●		50.0 ■	50.0 ▲	50.0 ◆
3.15	37.4 ○	35.4 ○		37.0 □	37.0 △	38.6 ◇
9.0	33.7 ⊙	32.8 ⊖		35.5 ◪	36.3 △	34.5 ◈
32.3	32.0 ⊙	31.3 ⊖	5.0 *	32.8 ◪	31.5 ▲	33.1 ◈

μ_o, μ_w, IN 10^{-2} POISE
$\sigma_{o\text{-}w}$ IN DYNES/CM

The significant scattering in the data may be because of:

- **Ignoring the tortuosity**
- **Ignoring the pore radius**

Capillary forces

Capillary number

The general trend of all experimental data show that

- ❑ **When $N_{ca} < 10^{-6}$ the residual oil remains constant**
- ❑ **When $N_{ca} > 10^{-6}$ the residual oil decreases smoothly**
- ❑ **At values on the order $N_{ca} = 10^{-2}$, virtually all oil recovered**

Mobilization of trapped oil

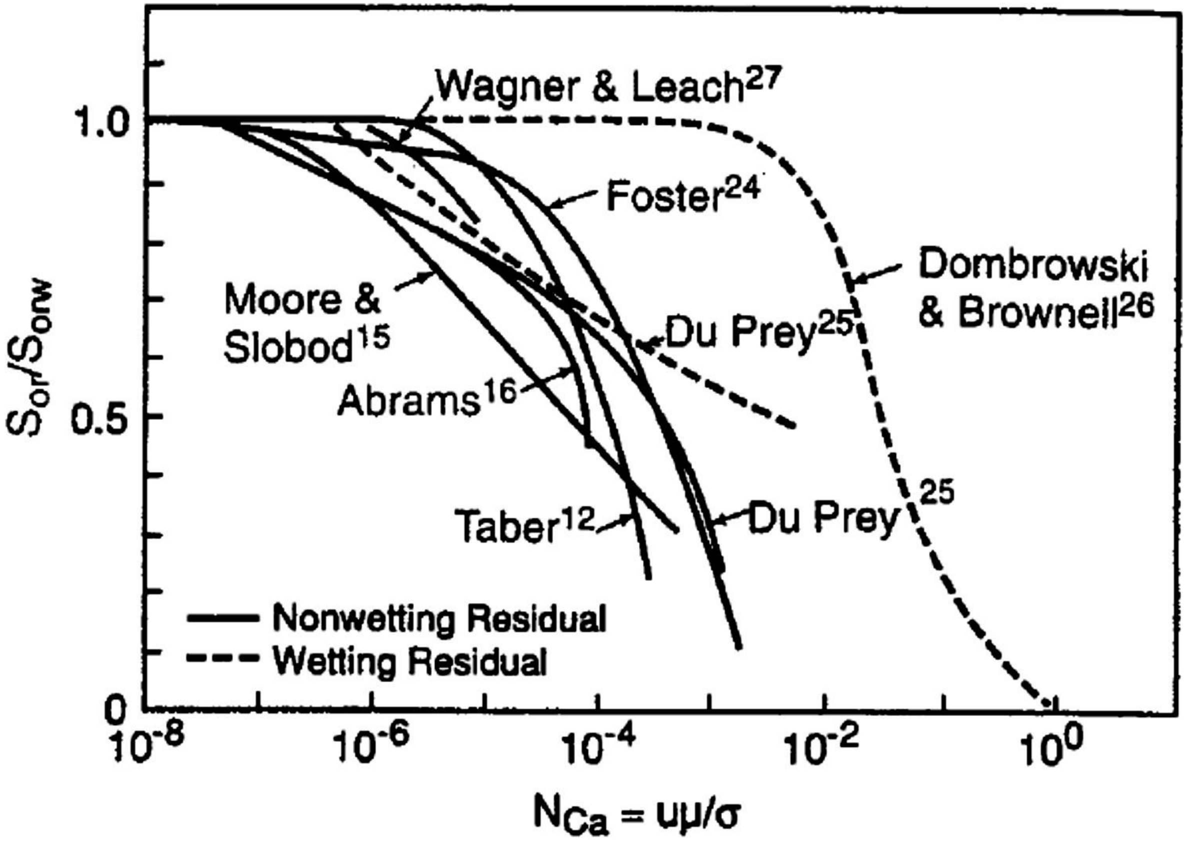
Theoretically the trapped oil can be mobilized in two different methods

1) **Alteration of viscous/capillary forces ratio (capillary number)**

2) **Alteration of phase behavior**

Alteration of viscous/capillary forces ratio (capillary number)

Extensive experiments were performed by varying N_{ca} in order to reduce the ratio and mobilize. Some of these works are summarized in this figure:

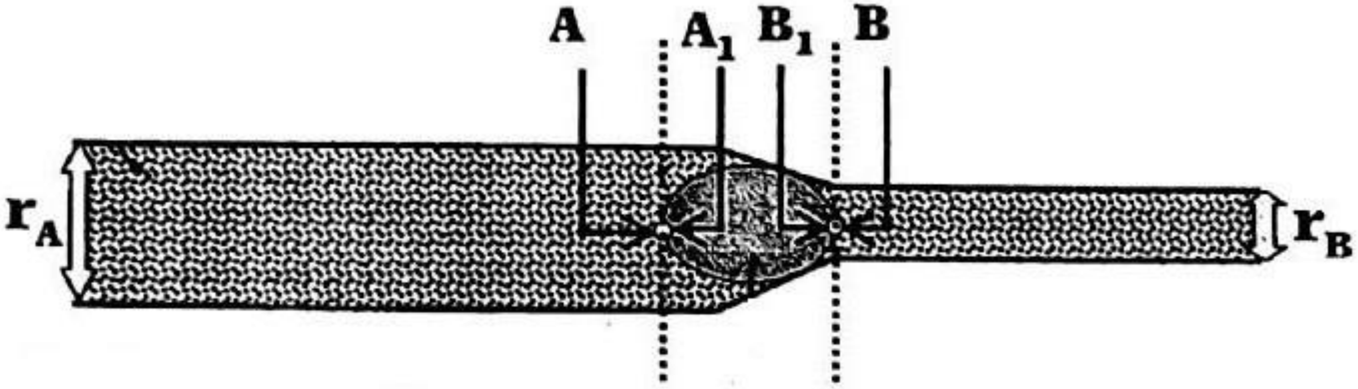


Phase trapping

Trapping in a single capillary – Jamin effect

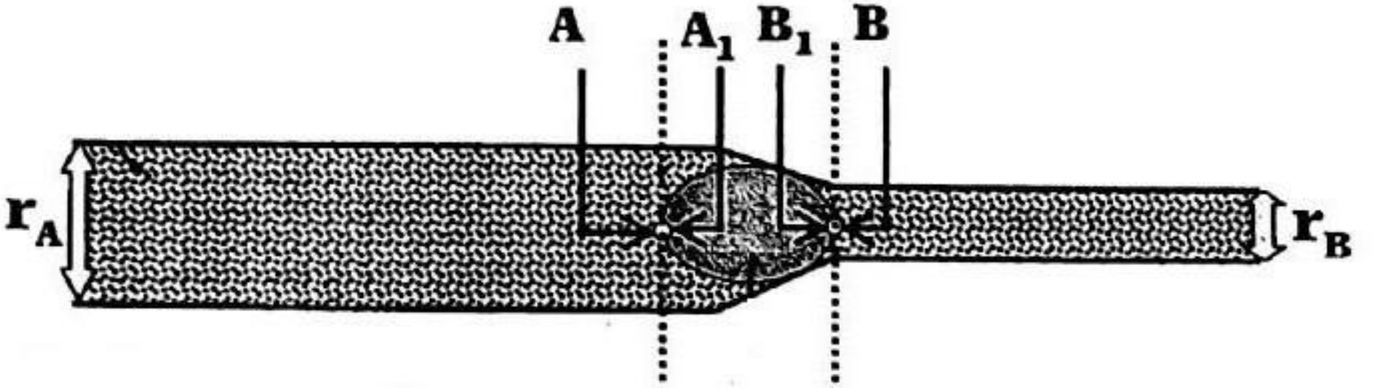
It has been recognized that some time the pressure required to force a nonwetting phase through a capillary system such as a porous rock can be quite high.

This phenomenon is called Jamin effect which is the result of the variation in pores radius



Phase trapping

Trapping in a single capillary – Jamin effect



$$P_{A1} = P_{B1}$$

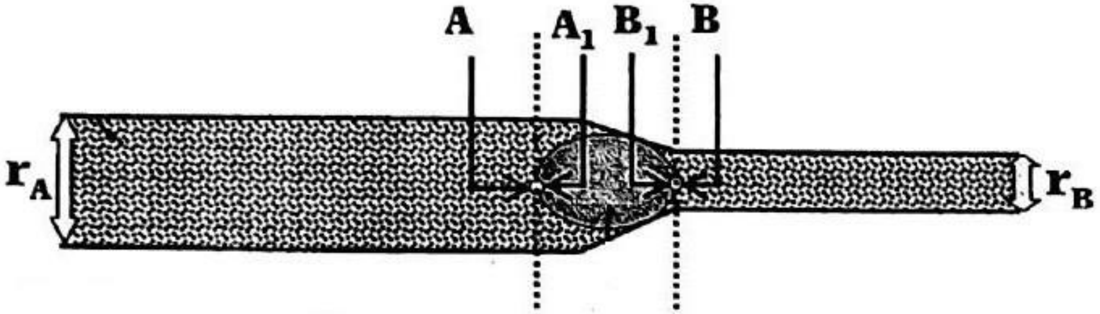
$$P_{A1} - P_A = \frac{2\sigma\cos\theta_A}{r_A}, \qquad P_{B1} - P_B = \frac{2\sigma\cos\theta_B}{r_B}$$

$$P_B - P_A = \frac{2\sigma_{ow}\cos\theta_A}{r_A} - \frac{2\sigma_{ow}\cos\theta_B}{r_B} \quad \Rightarrow \quad P_B - P_A = 2\sigma\left(\frac{1}{r_A} - \frac{1}{r_B}\right)\cos\theta_{ow}$$

Phase trapping

Trapping in a single capillary – Jamin effect

The equation show that the trapping mechanism depends on:



❑ **The pore structure of the porous medium, sizes**

❑ **Fluid/rock interactions related to wettability**

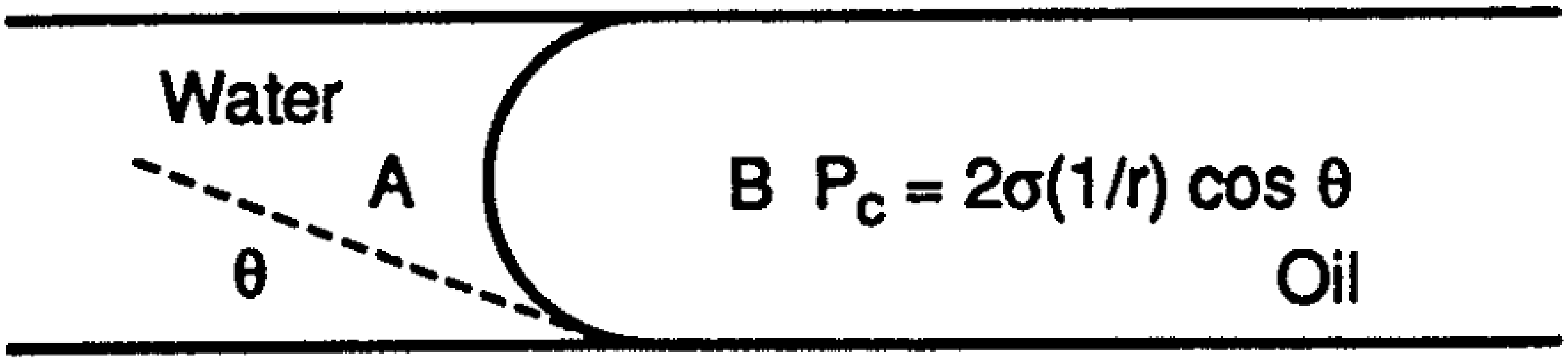
❑ **Fluid/fluid interaction reflected in IFT**

$$P_B - P_A = 2\sigma\left(\frac{1}{r_A} - \frac{1}{r_B}\right)\cos\theta_{ow}$$

Phase trapping

Extending the Jamin effect to various physical conditions

Case 1: Both phases are continuous



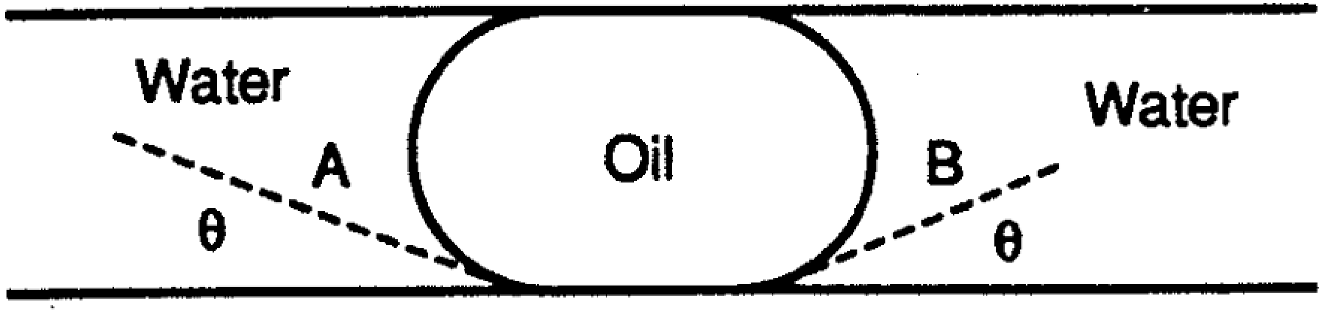
In this case, the pressure across the interface is just the capillary pressure

$$P_B - P_A = \frac{2\sigma_{ow}\cos\theta}{r}$$

Phase trapping

<u>Extending the Jamin effect to various physical conditions</u>

<u>Case 2: water is continuous but oil is discontinuous as droplet</u>



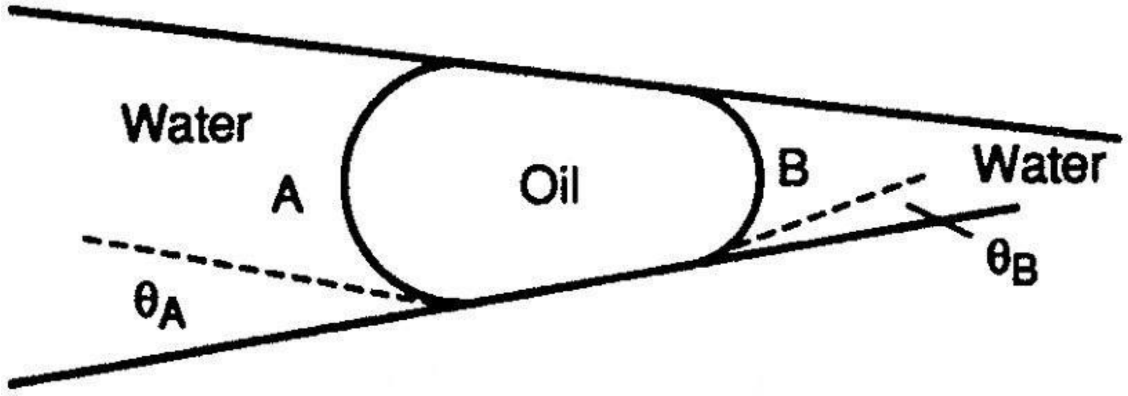
Because the conditions at points A and B are the same, pressure in the oil phase is higher than the pressure in the water phase by the value of Pc, but there is no pressure change across the drop

$$P_B - P_A = \frac{2\sigma_{ow}\cos\theta_A}{r_A} - \frac{2\sigma_{ow}\cos\theta_B}{r_B} = 0$$

Phase trapping

Extending the Jamin effect to various physical conditions

Case 3: water is continuous but oil is discontinuous as droplet and pore diameter is changing

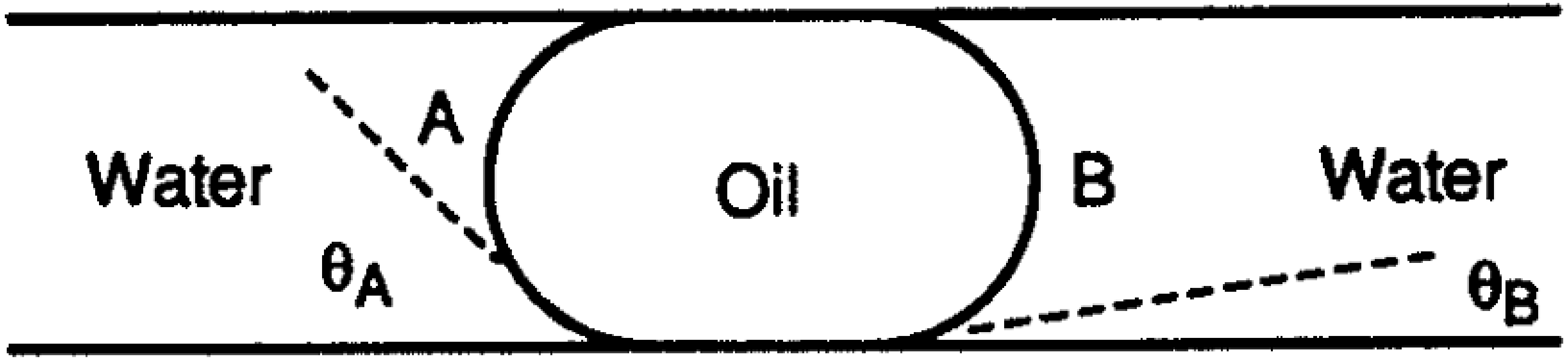


$$P_B - P_A = 2\sigma\left(\frac{1}{r_A} - \frac{1}{r_B}\right)\cos\theta_{ow}$$

Phase trapping

Extending the Jamin effect to various physical conditions

Case 4: water is continuous and oil is discontinuous as droplet but the wettability of rock is changing

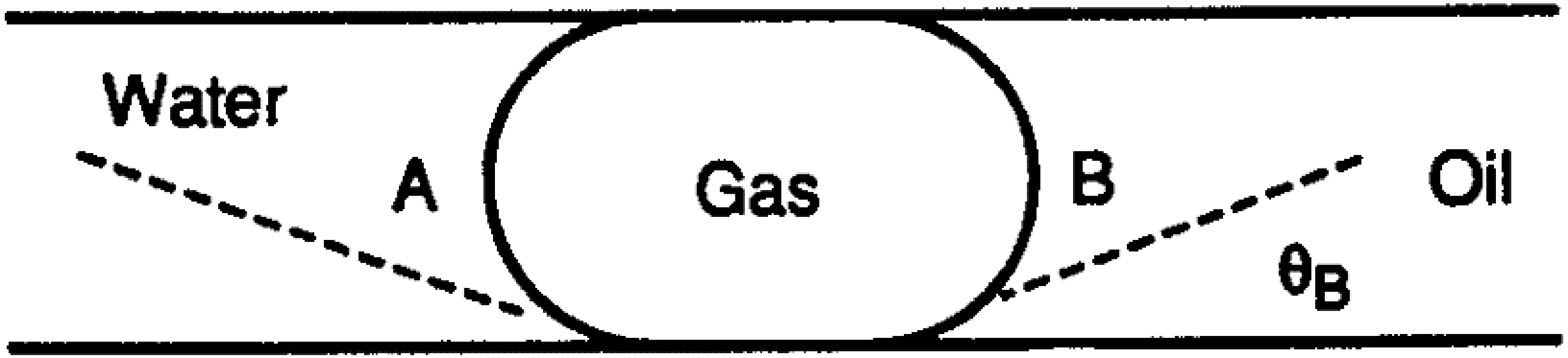


$$\mathbf{P_B - P_A = \frac{2\sigma_{ow}}{r}(\cos\theta_A - \cos\theta_B)}$$

Phase trapping

Extending the Jamin effect to various physical conditions

Case 5: a gas slug trapped at oil/water interface



$$P_B - P_A = \frac{2}{r}\left(\sigma_{gw}\cos\theta_A - \sigma_{go}\cos\theta_B\right)$$

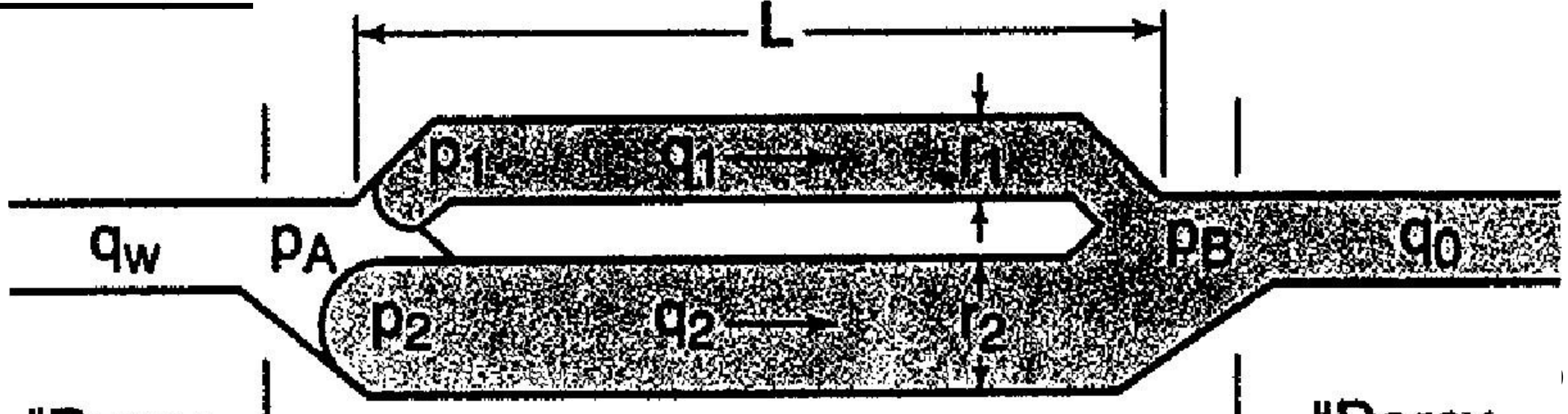
Phase trapping

Capillary doublet

Another case which causes oil trapping and therefore, reduction in microscopic efficiency of displacement process is capillary or pore doublet

Phase trapping

Capillary doublet



il phase

$$P_A - P_B = \underset{\Downarrow}{(P_A - P_{wi})} + \underset{\Downarrow}{(P_{wi} - P_{oi})} + \underset{\Downarrow}{(P_{oi} - P_B)}$$

Caused by viscous	Caused by capillary forces	Caused by viscous
forces in water phase	across the interface	forces in oil phase

Phase trapping

Capillary doublet

Substituting Poiseuille’s and capillary pressure equations into above equation for pore 1:

$$P_B - P_A = -\frac{8\mu_w L_w v_1}{r_1^2} + \frac{2\sigma\cos\theta}{r_1} - \frac{8\mu_o L_o v_1}{r_1^2}$$

Now for simplicity

$$\mu_w = \mu_o \qquad \& \qquad L = L_w + L_o$$

Phase trapping

Capillary doublet

So:

$$\Delta P_{BA} = -\frac{8\mu L v_1}{r_1^2} + \frac{2\sigma\cos\theta}{r_1}$$

In the pore doublet model, the same pressure drop exists across both pores until water breaks through from one pore. Thus, for pore 2, we can also write

$$\Delta P_{BA} = -\frac{8\mu L v_2}{r_2^2} + \frac{2\sigma\cos\theta}{r_2}$$

Phase trapping

Capillary doublet

On the other hand, we have

$$P_{C,2} < P_{C,1} \quad \text{because} \quad r_2 > r_1$$

Substituting for the capillary pressure in previous equations and considering the above inequality:

$$v_1 > \frac{\sigma \cdot \cos\theta \cdot r_1^2}{4\mu L}\left(\frac{1}{r_1} - \frac{1}{r_2}\right)$$

$$\Delta P_{BA} < P_{c,2} \quad \Rightarrow \quad -\frac{8\mu L v_1}{r_1^2} + P_{c,1} < P_{c,2} \quad \Rightarrow \quad -\frac{8\mu L v_1}{r_1^2} < P_{c,2} - P_{c,1}$$

Phase trapping

Example

Consider the oil displacement by water in a single pore of radius r at a velocity of 1 ft/D. the length of the pore is 0.02 in, the viscosity is 1 cp and the IFT is 30 dynes/cm. the contact angle is zero. Calculate the pressure difference, P_B-P_A for different radius values.

Solution

The derived equation can be used for these calculations and the results are given in the following table.

$$\Delta P_{BA} = -\frac{8\mu L v_1}{r_1^2} + \Delta P_{c,1}$$

Phase trapping

Solution

Capillary and viscous forces for different sizes of pore radii			
Pore radius, μm	$-\frac{8\mu L V_1}{r^2}$, psi	ΔP_c, psi	P_B-P_A
2.5	-3.250×10^{-4}	3.45	3.45
5	-0.810×10^{-4}	1.73	1.73
10	-0.200×10^{-4}	0.86	0.86
25	-0.033×10^{-4}	0.35	0.35
50	-0.056×10^{-4}	0.17	0.17
100	-0.014×10^{-4}	0.086	0.086

Phase trapping

$$\Delta P_{BA} = -\frac{8\mu L v_1}{r_1^2} + \frac{2\sigma\cos\theta}{r_1} \qquad \Delta P_{BA} = -\frac{8\mu L v_2}{r_2^2} + \frac{2\sigma\cos\theta}{r_2}$$

Solution

Now let the radius of pore 1 to be 2.5 μm and calculate values of V_1 for which the velocity in pore is zero, $V_2=0$, and therefore the oil in pore 2 is immobilized.

The condition for which $V_2>0$ was,

$$v_1 > \frac{\sigma \cdot \cos\theta \cdot r_1^2}{4\mu L}\left(\frac{1}{r_1} - \frac{1}{r_2}\right)$$

V2=0 if at least

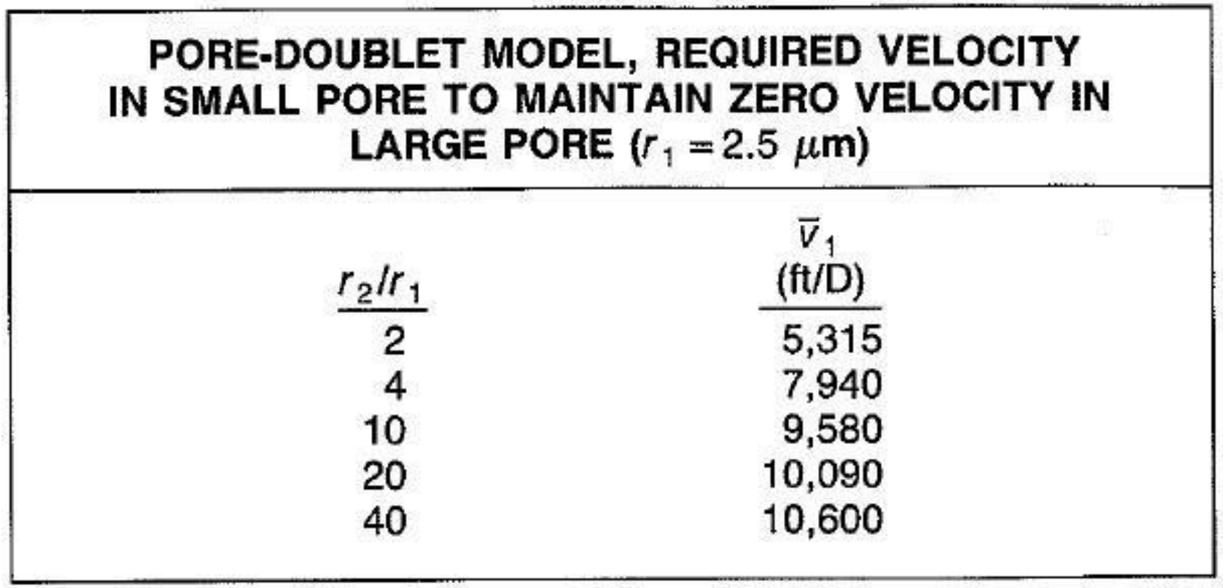
$$v_1 = \frac{\sigma \cdot \cos\theta \cdot r_1^2}{4\mu L}\left(\frac{1}{r_1} - \frac{1}{r_2}\right)$$

Phase trapping

Solution

The values of v_1 are much larger than normal reservoir velocity, hence to displace oil from pore 2, very large velocities are required. Therefore, oil is displaced just from the small pore.

In fact, for velocities that could be present in a reservoir (i.e. 1 ft/D) during the displacement in pore 1, the computed velocity in pore 2



PORE-DOUBLET MODEL, REQUIRED VELOCITY IN SMALL PORE TO MAINTAIN ZERO VELOCITY IN LARGE PORE ($r_1 = 2.5$ μm)

r_2/r_1	$\bar{v}_1$ (ft/D)
2	5,315
4	7,940
10	9,580
20	10,090
40	10,600

would be negative and reservoir flow is limited and probably does not occur.

Phase trapping

Contact angle hysteresis:

Solution

The isolated oil drop could also be trapped in a uniform pore by hysteresis in contact angles. If the recording contact angle were 0 degree, the advancing contact angle for the motionless of drop can be computed from:

$$P_B - P_A = \frac{2\sigma_{ow}}{r}\left(\cos\theta_A - \cos\theta_B\right) \Rightarrow -22.6 = \frac{2\times 30}{10\mu m \times 10^{-4} cm/\mu m}\left(\cos\theta_A - \cos\theta_B\right)$$

$$\cos\theta_B - \cos\theta_A = 3.767\times 10^{-4} \quad \Rightarrow \quad \theta_A = 1.57^0$$

This example shows that a small change in contact angle caused by hysteresis or a small change in pore radius would sufficient to trap the oil droplets.

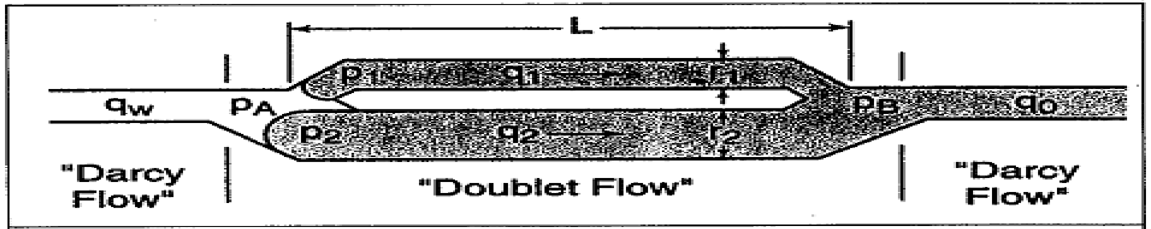


Fig. 2.17—Pore-doublet model for illustration of displacement and trapping of oil filament (from Willhite[1]).

Considering the pressure difference between Points A and B after water enters Pore 1, for either pore there results

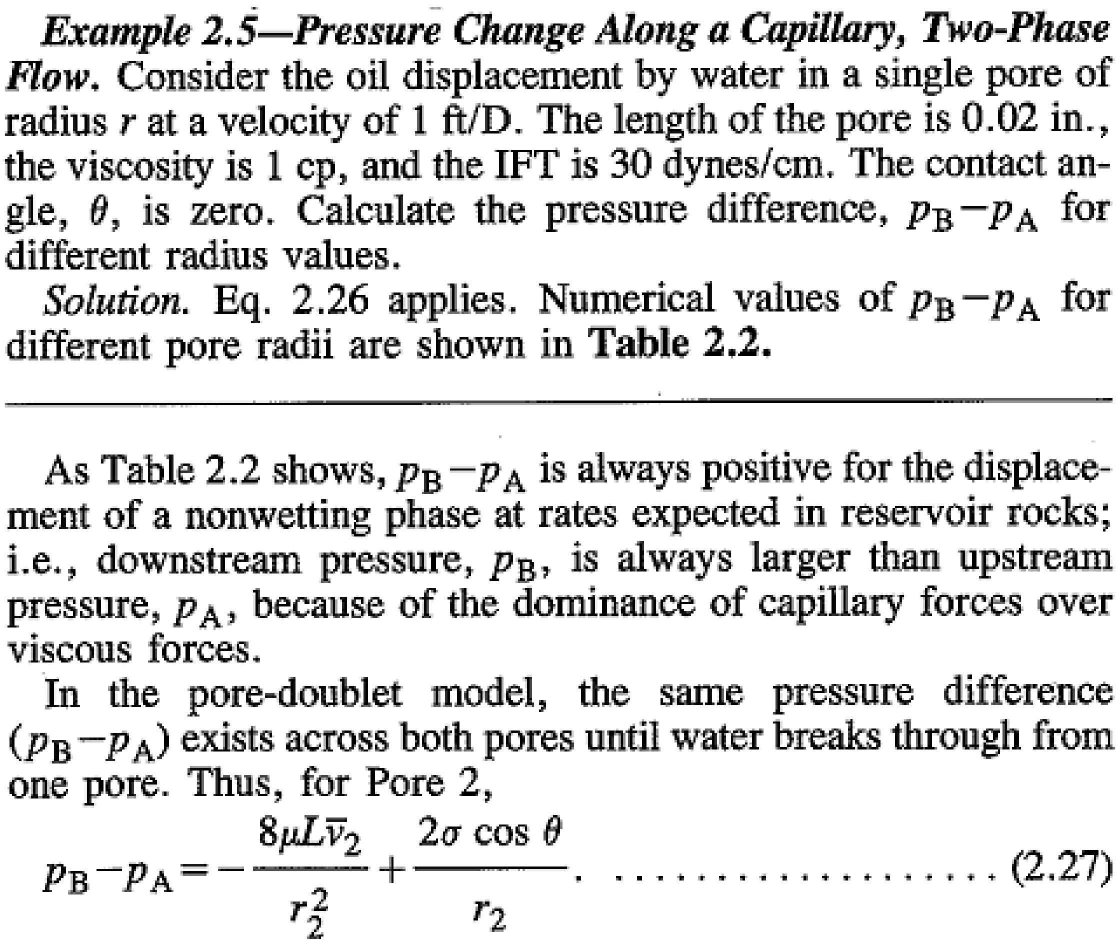
$$p_A - p_B = \underset{\substack{\text{pressure drop caused by}\\ \text{viscous forces in water}\\ \text{phase}}}{p_A - p_{wi}} \quad \underset{\substack{\text{pressure change}\\ \text{across interface}\\ \text{resulting from}\\ \text{capillary force}}}{+p_{wi} - p_{oi}} \quad \underset{\substack{\text{pressure drop in}\\ \text{oil phase caused}\\ \text{by viscous forces}}}{+p_{oi} - p_B} . \quad \text{(2.24)}$$

Substitution of Eqs. 2.22 and 2.23 into Eq. 2.24 for Pore 1 yields Eq. 2.25 for downstream minus upstream pressure.

$$p_B - p_A = -\frac{8\mu_w L_w \bar{v}_1}{r_1^2} + \frac{2\sigma \cos\theta}{r_1} - \frac{8\mu_o L_o \bar{v}_1}{r_1^2} . \quad \text{(2.25)}$$

Because $\mu_o = \mu_w = \mu$ and $L \approx L_w + L_o$,

$$\Delta p_{BA} = p_B - p_A = \underset{\substack{\text{viscous}\\ \text{pressure}\\ \text{drop}}}{-\frac{8\mu L \bar{v}_1}{r_1^2}} \underset{\substack{\text{capillary}\\ \text{pressure}}}{+\Delta P_{c1}} . \quad \text{(2.26)}$$



Example 2.5—Pressure Change Along a Capillary, Two-Phase Flow. Consider the oil displacement by water in a single pore of radius r at a velocity of 1 ft/D. The length of the pore is 0.02 in., the viscosity is 1 cp, and the IFT is 30 dynes/cm. The contact angle, θ, is zero. Calculate the pressure difference, $p_B - p_A$ for different radius values.

Solution. Eq. 2.26 applies. Numerical values of $p_B - p_A$ for different pore radii are shown in **Table 2.2.**

As Table 2.2 shows, $p_B - p_A$ is always positive for the displacement of a nonwetting phase at rates expected in reservoir rocks; i.e., downstream pressure, p_B, is always larger than upstream pressure, p_A, because of the dominance of capillary forces over viscous forces.

In the pore-doublet model, the same pressure difference $(p_B - p_A)$ exists across both pores until water breaks through from one pore. Thus, for Pore 2,

$$p_B - p_A = -\frac{8\mu L \bar{v}_2}{r_2^2} + \frac{2\sigma \cos\theta}{r_2}. \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots (2.27)$$

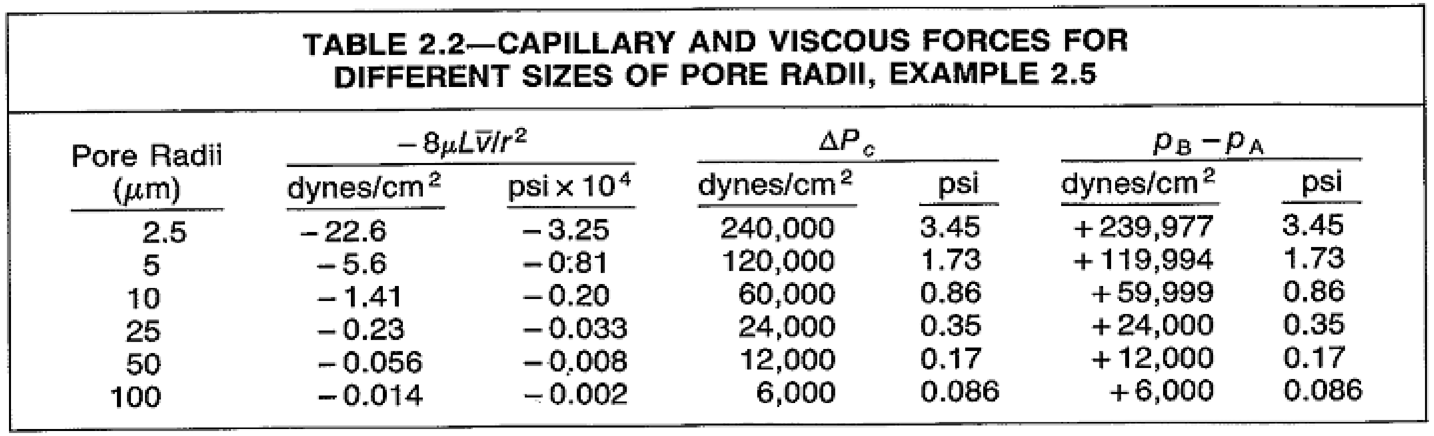
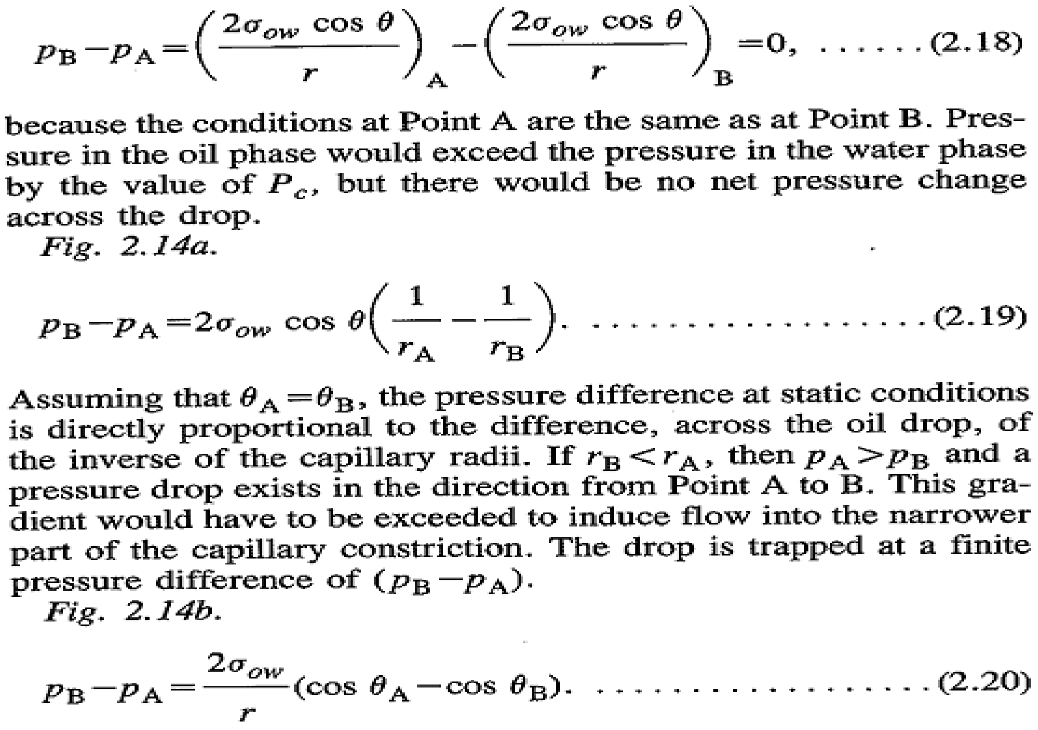


TABLE 2.2—CAPILLARY AND VISCOUS FORCES FOR DIFFERENT SIZES OF PORE RADII, EXAMPLE 2.5

Pore Radii (μm)	$-8\mu L\bar{v}/r^2$		ΔP_c		$p_B - p_A$	
	dynes/cm^2	psi $\times 10^4$	dynes/cm^2	psi	dynes/cm^2	psi
2.5	−22.6	−3.25	240,000	3.45	+239,977	3.45
5	−5.6	−0.81	120,000	1.73	+119,994	1.73
10	−1.41	−0.20	60,000	0.86	+59,999	0.86
25	−0.23	−0.033	24,000	0.35	+24,000	0.35
50	−0.056	−0.008	12,000	0.17	+12,000	0.17
100	−0.014	−0.002	6,000	0.086	+6,000	0.086



$$p_B - p_A = \left(\frac{2\sigma_{ow}\cos\theta}{r}\right)_A - \left(\frac{2\sigma_{ow}\cos\theta}{r}\right)_B = 0, \quad \ldots\ldots (2.18)$$

because the conditions at Point A are the same as at Point B. Pressure in the oil phase would exceed the pressure in the water phase by the value of P_c, but there would be no net pressure change across the drop.

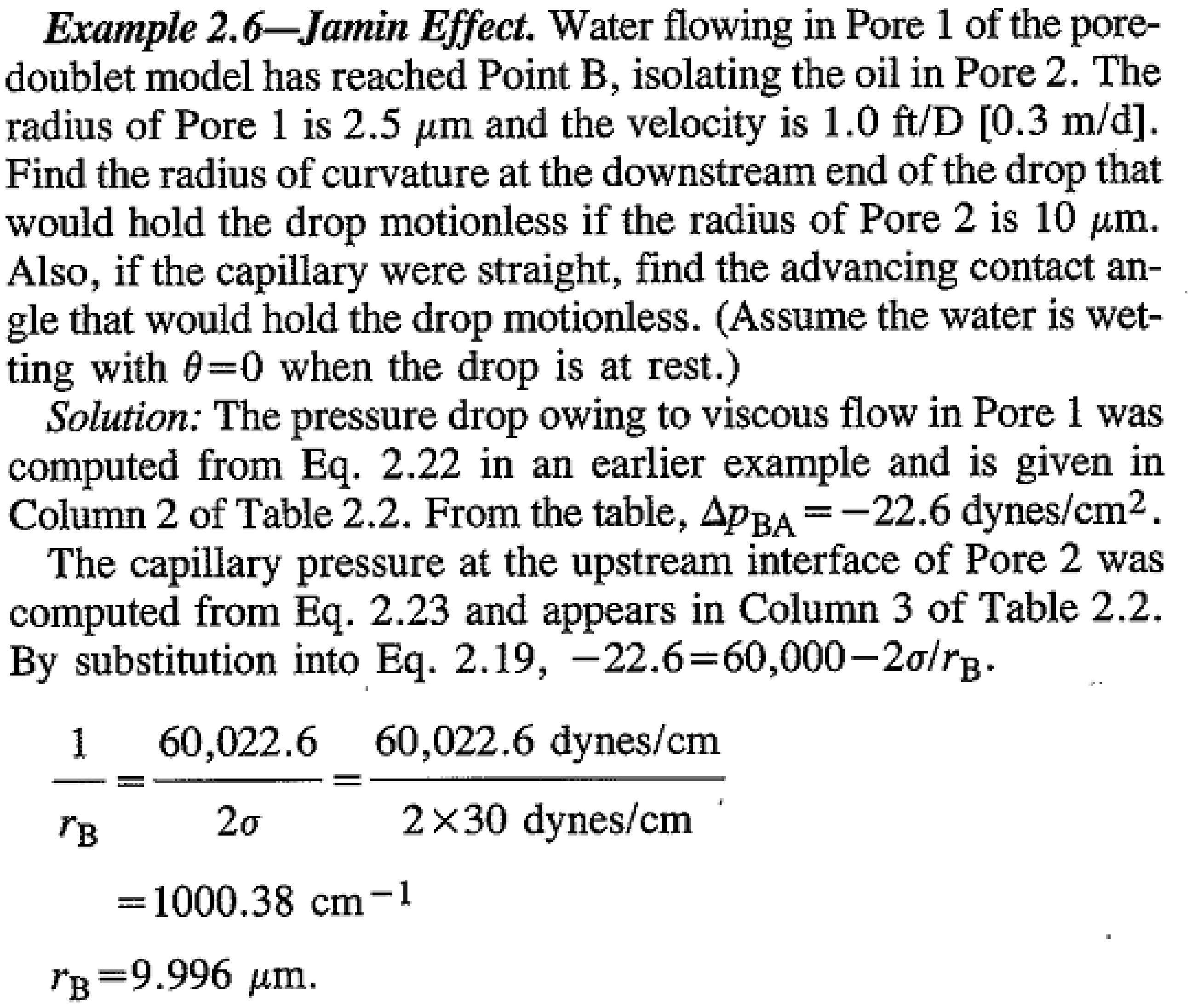
Fig. 2.14a.

$$p_B - p_A = 2\sigma_{ow}\cos\theta\left(\frac{1}{r_A} - \frac{1}{r_B}\right). \quad \ldots\ldots\ldots\ldots\ldots\ldots (2.19)$$

Assuming that $\theta_A = \theta_B$, the pressure difference at static conditions is directly proportional to the difference, across the oil drop, of the inverse of the capillary radii. If $r_B < r_A$, then $p_A > p_B$ and a pressure drop exists in the direction from Point A to B. This gradient would have to be exceeded to induce flow into the narrower part of the capillary constriction. The drop is trapped at a finite pressure difference of $(p_B - p_A)$.

Fig. 2.14b.

$$p_B - p_A = \frac{2\sigma_{ow}}{r}(\cos\theta_A - \cos\theta_B). \quad \ldots\ldots\ldots\ldots\ldots\ldots (2.20)$$



Example 2.6—Jamin Effect. Water flowing in Pore 1 of the pore-doublet model has reached Point B, isolating the oil in Pore 2. The radius of Pore 1 is 2.5 μm and the velocity is 1.0 ft/D [0.3 m/d]. Find the radius of curvature at the downstream end of the drop that would hold the drop motionless if the radius of Pore 2 is 10 μm. Also, if the capillary were straight, find the advancing contact angle that would hold the drop motionless. (Assume the water is wetting with $\theta=0$ when the drop is at rest.)

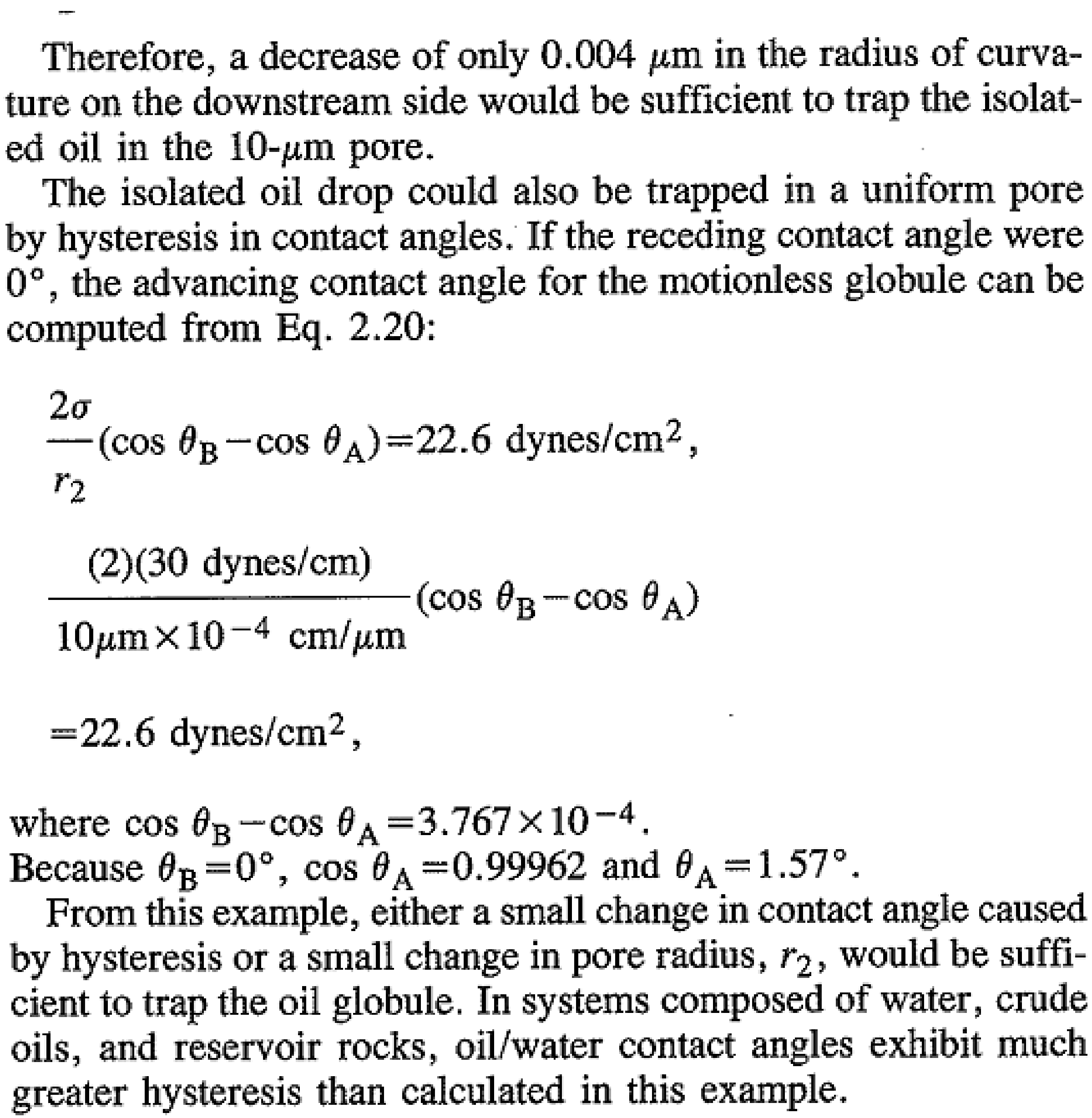
Solution: The pressure drop owing to viscous flow in Pore 1 was computed from Eq. 2.22 in an earlier example and is given in Column 2 of Table 2.2. From the table, $\Delta p_{BA}=-22.6$ dynes/cm^2.

The capillary pressure at the upstream interface of Pore 2 was computed from Eq. 2.23 and appears in Column 3 of Table 2.2. By substitution into Eq. 2.19, $-22.6=60{,}000-2\sigma/r_B$.

$$\frac{1}{r_B}=\frac{60{,}022.6}{2\sigma}=\frac{60{,}022.6 \text{ dynes/cm}}{2\times30 \text{ dynes/cm}}$$

$$=1000.38 \text{ cm}^{-1}$$

$$r_B=9.996\ \mu\text{m}.$$



Therefore, a decrease of only 0.004 μm in the radius of curvature on the downstream side would be sufficient to trap the isolated oil in the 10-μm pore.

The isolated oil drop could also be trapped in a uniform pore by hysteresis in contact angles. If the receding contact angle were 0°, the advancing contact angle for the motionless globule can be computed from Eq. 2.20:

$$\frac{2\sigma}{r_2}(\cos\theta_B - \cos\theta_A) = 22.6 \text{ dynes/cm}^2,$$

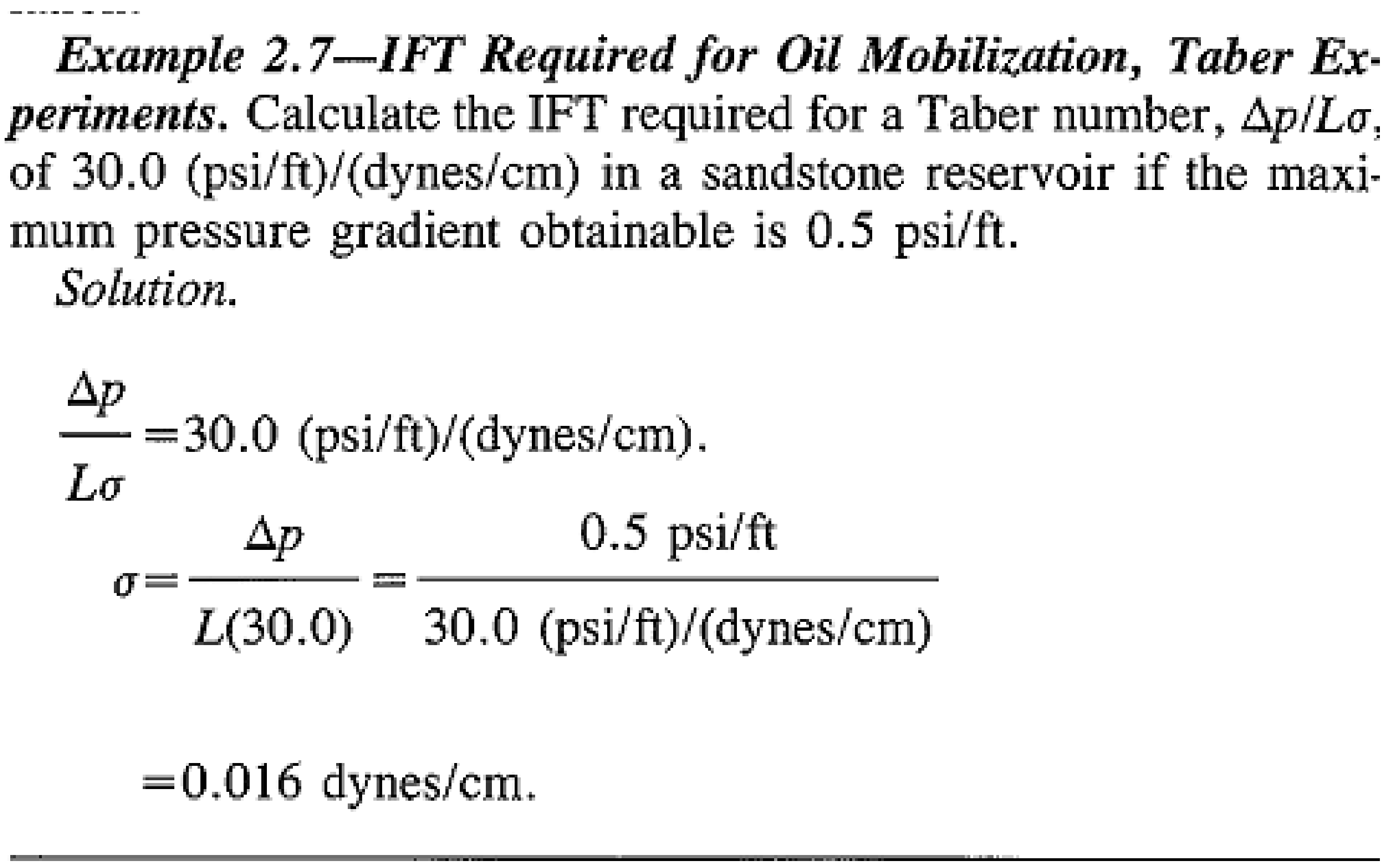
$$\frac{(2)(30 \text{ dynes/cm})}{10\mu\text{m} \times 10^{-4} \text{ cm}/\mu\text{m}}(\cos\theta_B - \cos\theta_A)$$

$$= 22.6 \text{ dynes/cm}^2,$$

where $\cos\theta_B - \cos\theta_A = 3.767 \times 10^{-4}$.

Because $\theta_B = 0°$, $\cos\theta_A = 0.99962$ and $\theta_A = 1.57°$.

From this example, either a small change in contact angle caused by hysteresis or a small change in pore radius, r_2, would be sufficient to trap the oil globule. In systems composed of water, crude oils, and reservoir rocks, oil/water contact angles exhibit much greater hysteresis than calculated in this example.



Example 2.7—IFT Required for Oil Mobilization, Taber Experiments. Calculate the IFT required for a Taber number, $\Delta p/L\sigma$, of 30.0 (psi/ft)/(dynes/cm) in a sandstone reservoir if the maximum pressure gradient obtainable is 0.5 psi/ft.

Solution.

$$\frac{\Delta p}{L\sigma} = 30.0 \text{ (psi/ft)/(dynes/cm)}.$$

$$\sigma = \frac{\Delta p}{L(30.0)} = \frac{0.5 \text{ psi/ft}}{30.0 \text{ (psi/ft)/(dynes/cm)}}$$

$$= 0.016 \text{ dynes/cm}.$$

Macroscopic or volumetric displacement efficiency of fluids in a reservoir

The overall displacement efficiency of any oil recovery process was defined as:

$$\mathbf{E} = \mathbf{E_D} \times \mathbf{E_V}$$

Microscopic displacement efficiency, E_D, and the effect of various parameters on it was discussed. Now the macroscopic or volumetric displacement efficiency and its variation with different parameters will be considered.

Oil recovery in any EOR displacement process depends also on the volume of reservoir contacted by the injected fluid. A quantitative measure of this contact is the volumetric displacement efficiency, E_V. Volumetric displacement is a macroscopic efficiency defined as the fraction of reservoir PV invaded تهاجم کردن by the injected fluid. Clearly E_V is a function of time in a

The parameters controlling E_v

Because in a reservoir heterogeneities may exist both in areal and vertical directions, it is more convenience to express the volumetric displacement efficiency as the product of areal and vertical displacement efficiencies:

$$\mathbf{E_V = E_A \times E_I}$$

$$\mathbf{E_A = \frac{\text{Area of swept}}{\text{Total reservoir area}}}$$

$$\mathbf{E_I = \frac{\text{Pore space invaded by the injected fluid}}{\text{Pore space enclosed in all layers behind the location of front}}}$$

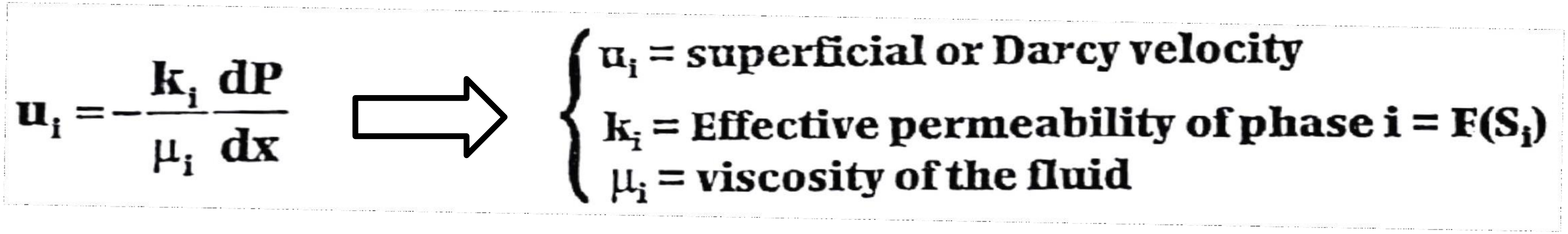
Areal displacement efficiency, E_A

Areal displacement efficiency is controlled by Four main parameters (Macroscopic or volumetric displacement efficiency):

1) **Mobility ratio of displacing and displaced fluids**
2) **Injection and production well pattern**
3) **Reservoir permeability heterogeneity**
4) **Relative importance of gravity and viscous forces**

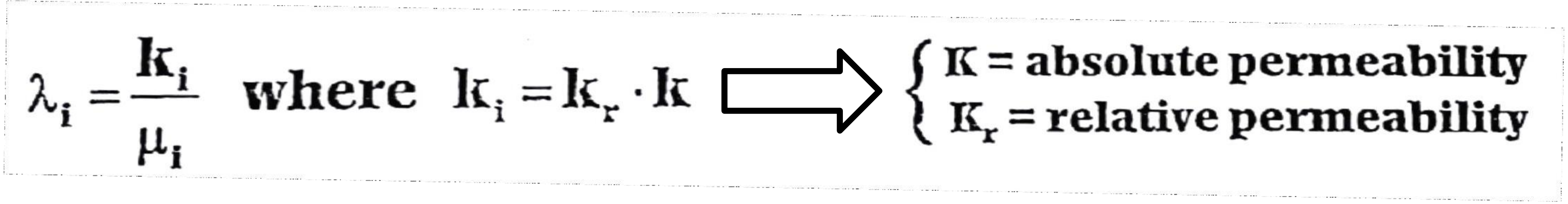
Mobility of fluids flowing in a porous medium

As discussed in reservoir engineering, mobility of a fluid phase flowing in a porous medium is defined on the basis of Darcy's law



$$u_i = -\frac{k_i}{\mu_i}\frac{dP}{dx} \quad \Longrightarrow \quad \begin{cases} u_i = \text{superficial or Darcy velocity} \\ k_i = \text{Effective permeability of phase i} = F(S_i) \\ \mu_i = \text{viscosity of the fluid} \end{cases}$$

Mobility of the fluid phase is defined as:



$$\lambda_i = \frac{k_i}{\mu_i} \quad \text{where} \quad k_i = k_r \cdot k \quad \Longrightarrow \quad \begin{cases} K = \text{absolute permeability} \\ K_r = \text{relative permeability} \end{cases}$$

Mobility ratio of displacing and displaced fluids

$$\mathbf{M} = \frac{\lambda_D}{\lambda_d} \Rightarrow \begin{cases} \lambda_D = \textbf{Mobility of displacing phase} \\ \lambda_d = \textbf{Mobility of displaced phase} \end{cases}$$

The parameters which almost takes into accounts the effect of almost all variables is the mobility ratio of the displaced and displacing fluids. Experimental studies also confirmed that both E_A and E_I are strongly influenced by mobility ratio in either miscible and immiscible displacement processes.

For this reason, almost all experimental measurements of the areal and vertical displacement efficiencies of various EOR processes are correlated in terms of mobility ratio

The importance of mobility ratio

For miscible displacements, when only one phase is flowing

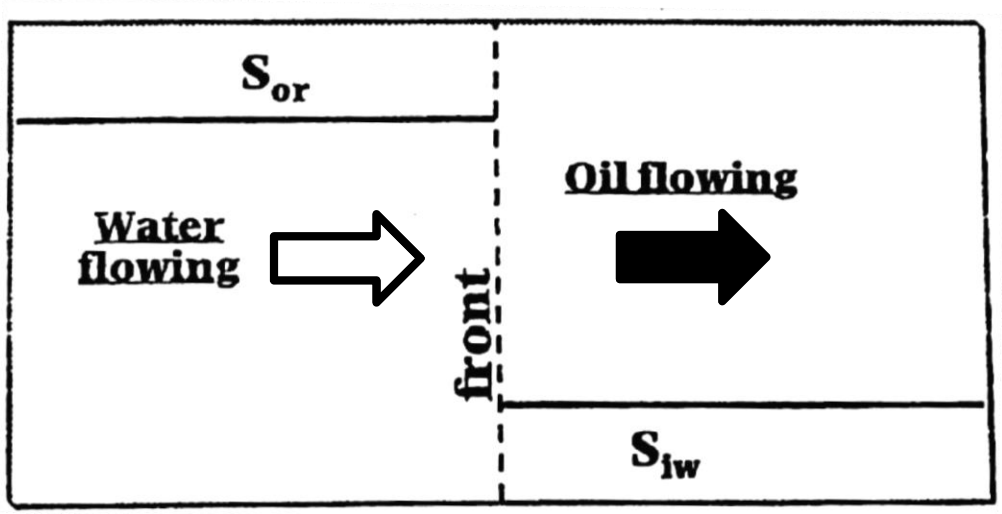
$$M = \frac{\mu_d}{\mu_D} \Rightarrow \begin{cases} \mu_d = \text{viscosity of the displaced phase} \\ \mu_D = \text{viscosity of the displacing phase} \end{cases}$$

For immiscible displacement with only displacing fluid flowing behind the front and only displaced phase flowing ahead of front, we can write:

$$M = \left(\frac{k_{rD}}{\mu_D}\right)_{S_{dr}} \cdot \left(\frac{\mu_d}{k_{rd}}\right)_{S_{Dr}}$$

For water flooding this equation becomes:

$$M = \left(\frac{k_{rw}}{\mu_w}\right)_{S_{or}} \cdot \left(\frac{\mu_o}{ko}\right)_{S_{iw}}$$



Reservoir permeability heterogeneity

Permeability heterogeneity often has a marked effect on the areal sweep.

This effect may be quite different from reservoir to reservoir. Thus, it is difficult to develop generalized correlations for this variable.

Correlations of areal displacement efficiency based on physical model studies

Physical models have been widely used to studies of areal sweep efficiency. Specific well patterns are represented by model configurations that appropriate fractions of the pattern being investigated.

For example one-quarter of a five-spot pattern with an injection well on one corner and a production well on the opposite corner of the model.

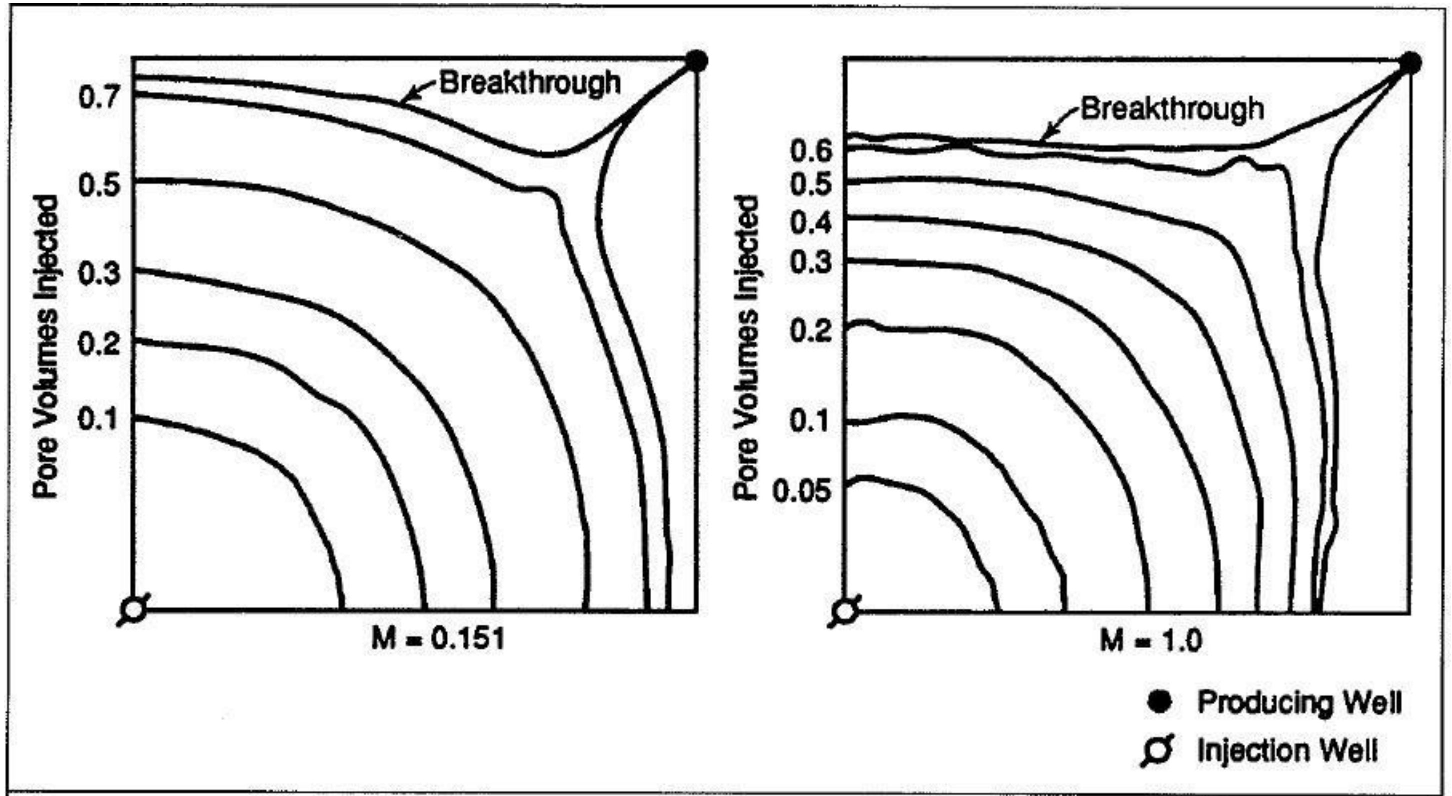
Gravity effects are eliminated by adjusting the densities of the different fluids or by using thin models so that gravity override or underride is minimized.

Correlations of areal displacement efficiency based on physical model studies

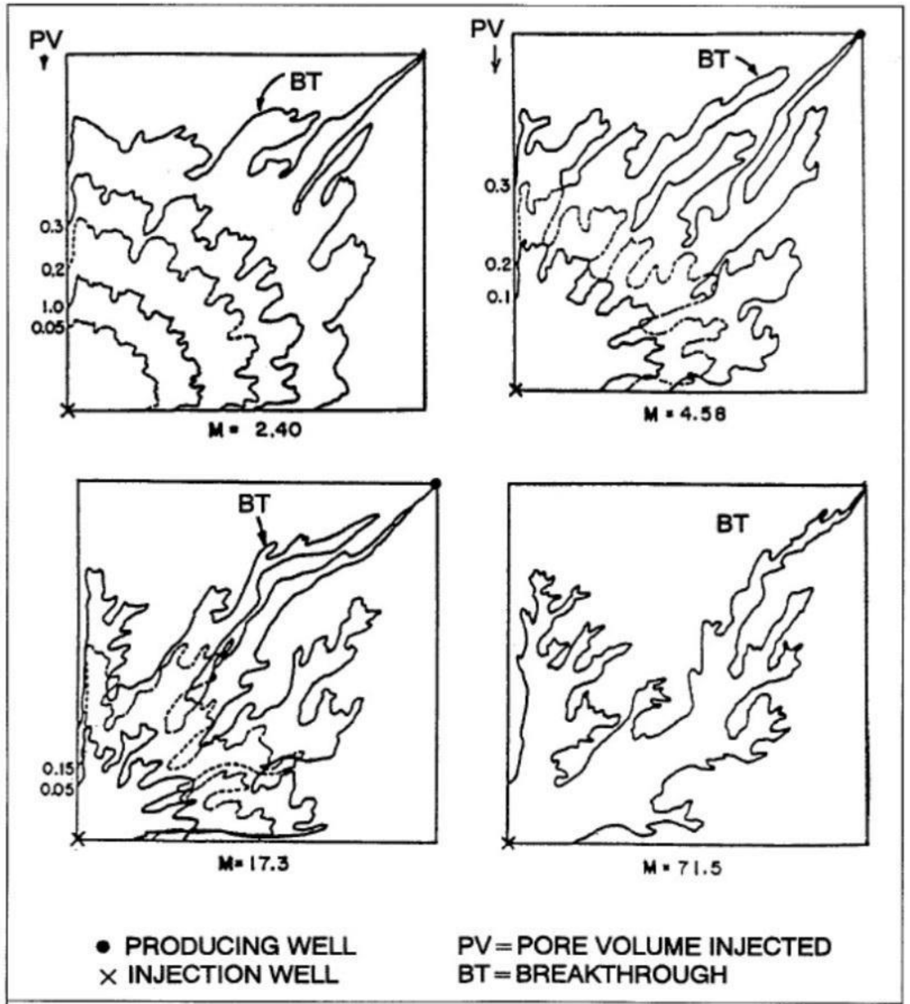
Because laboratory models are small in size compared with a reservoir, physical model scaling laws should be used in constructing and operating the models so the **hydrodynamic and geometric similarity** are exist between model and the specific reservoir.

In these models the front between the displacing and displaced fluids are monitored by X-ray shadowgraph techniques. One of the fluids is tagged with a substance that absorbs X-ray while the other fluid is invisible to X-ray.

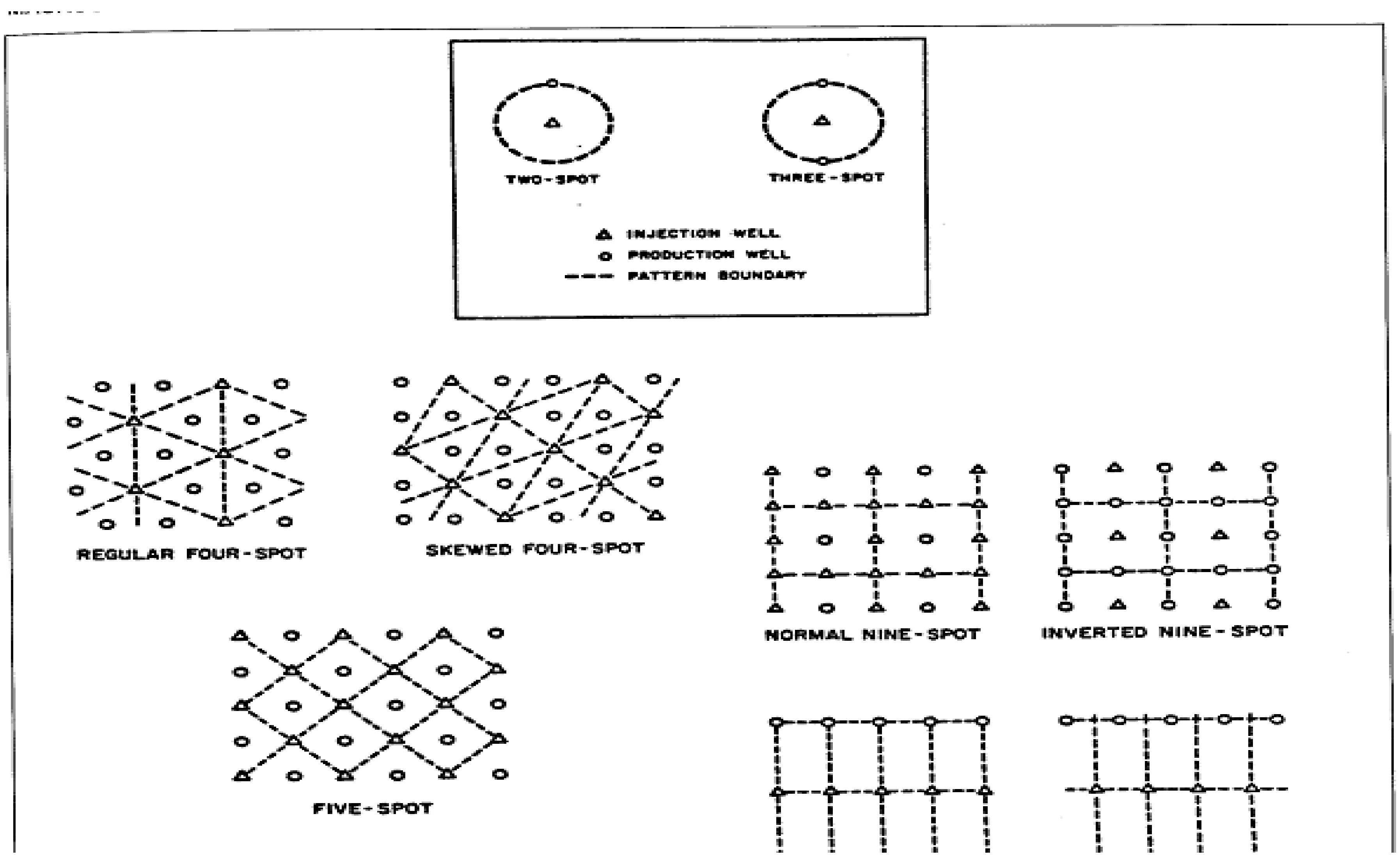
The figures show fluid fronts for immiscible and miscible processes at different points for different mobility ratios.



Miscible displacement in a quarter of a five-spot pattern at mobility ratios ≤ 1.0 (from Habermann).



Miscible displacement in a quarter of a five-spot pattern at mobility ratios greater than unity; viscous fingering.


TWO-SPOT
THREE-SPOT
INJECTION WELL
PRODUCTION WELL
PATTERN BOUNDARY
REGULAR FOUR-SPOT
SKEWED FOUR-SPOT
FIVE-SPOT
NORMAL NINE-SPOT
INVERTED NINE-SPOT

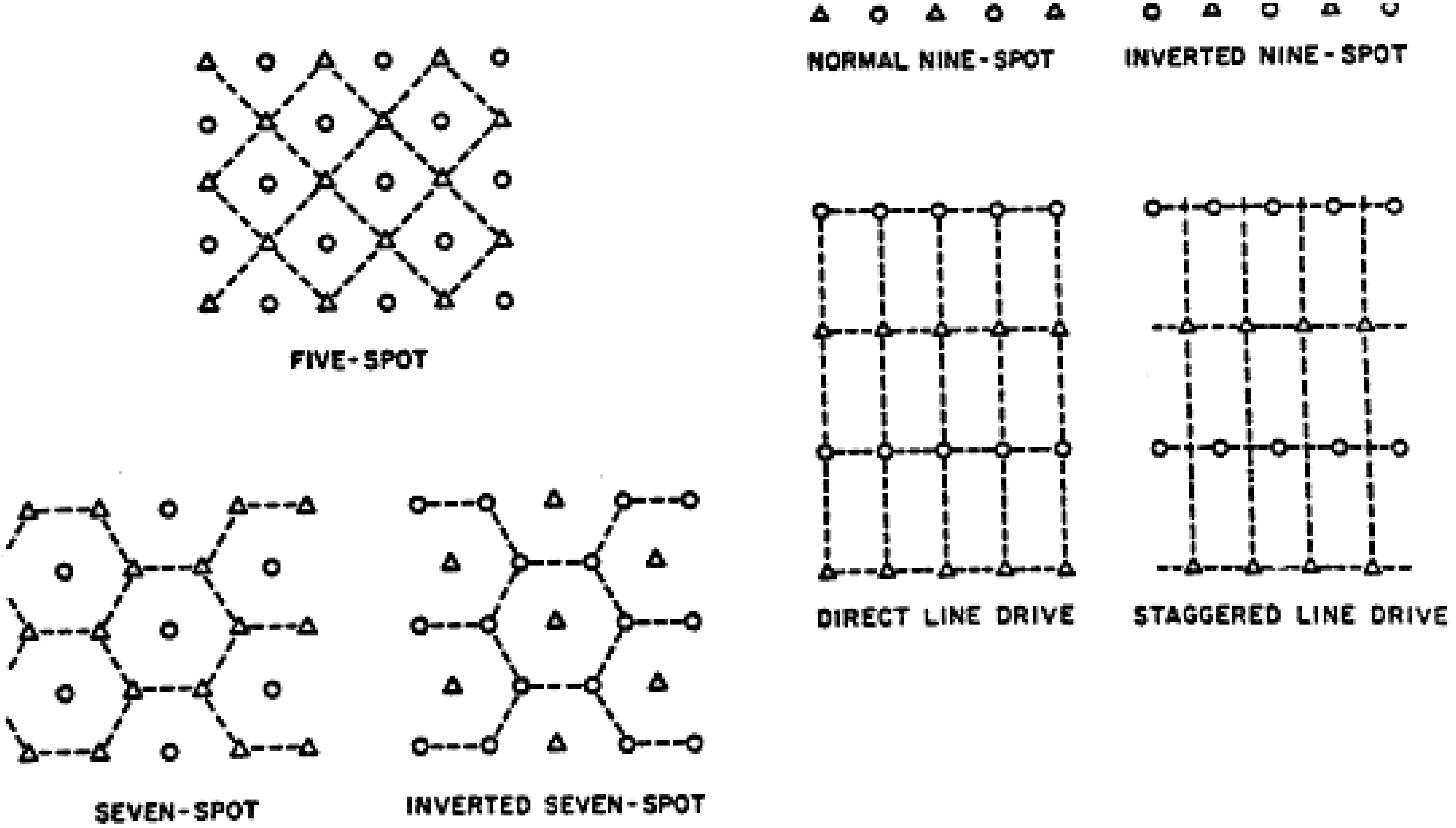
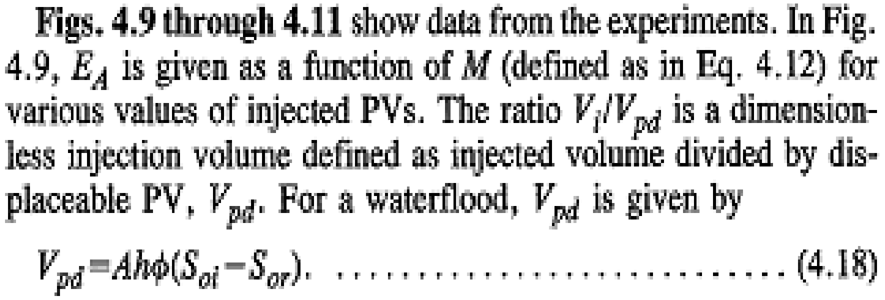


Fig. 4.1—Flooding patterns (from Craig[2]).

Prediction of areal displacement performance for five-spot pattern



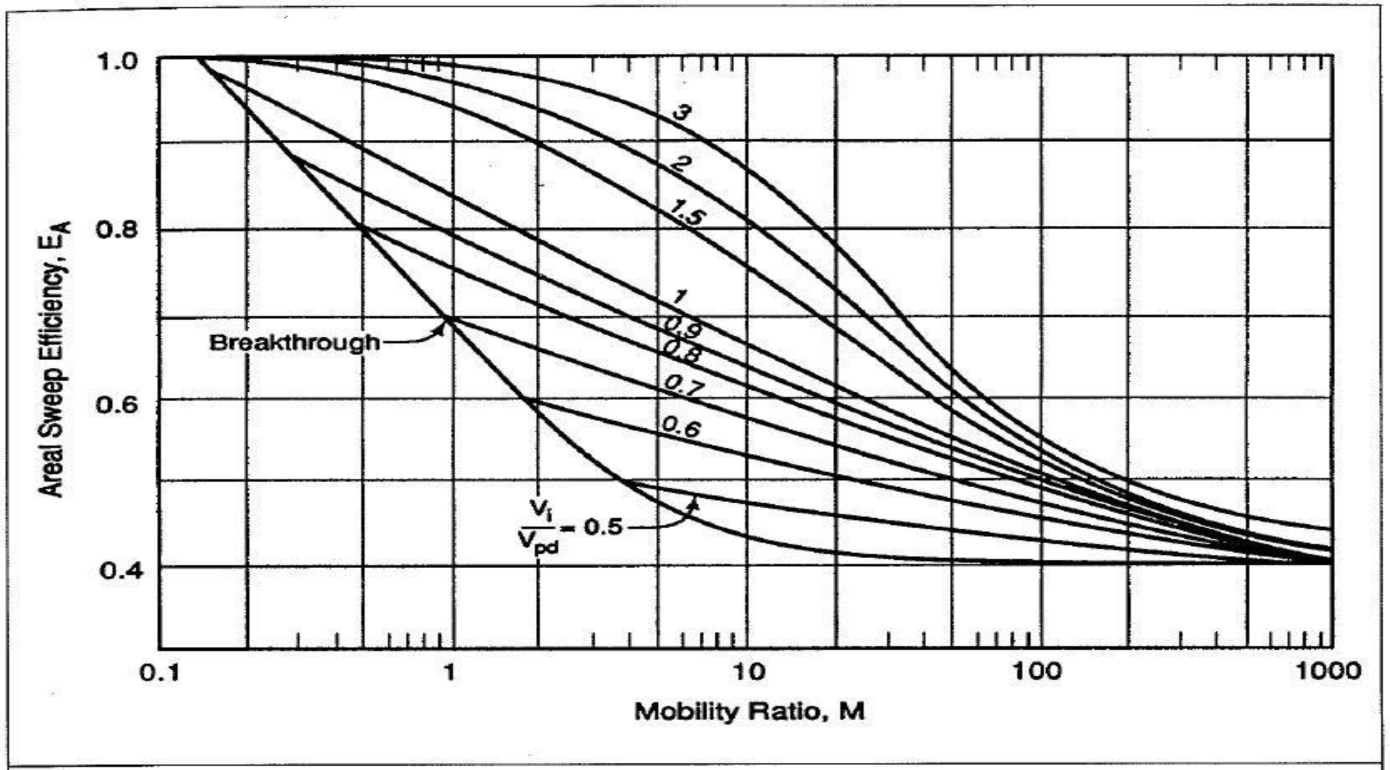
Figs. 4.9 through 4.11 show data from the experiments. In Fig. 4.9, E_A is given as a function of M (defined as in Eq. 4.12) for various values of injected PVs. The ratio V_i/V_{pd} is a dimensionless injection volume defined as injected volume divided by displaceable PV, V_{pd}. For a waterflood, V_{pd} is given by

$$V_{pd}=Ah\phi(S_{oi}-S_{or}). \qquad (4.18)$$

Figure 1

In this figure, E_A, is given as a function of M for various values of injected PVs given as the ratio of V_i/V_{pd} where V_i is injected volume and V_{pd} is displaceable pore volume. For water flood it is equal to:

$$V_{pd}=Ah\phi(S_{oi}-S_{or})$$



Areal sweep efficiency as a function of mobility ratio and injected volume, five-spot pattern (from Caudle and Witte).

Prediction of areal displacement performance for five-spot pattern

Figure 2

In this figure, E_A, is given as a function of M for different values of fractional flow of the displacing phase f_D at the production well

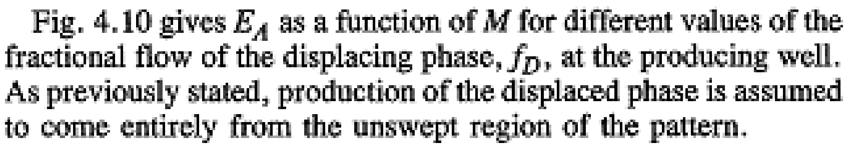
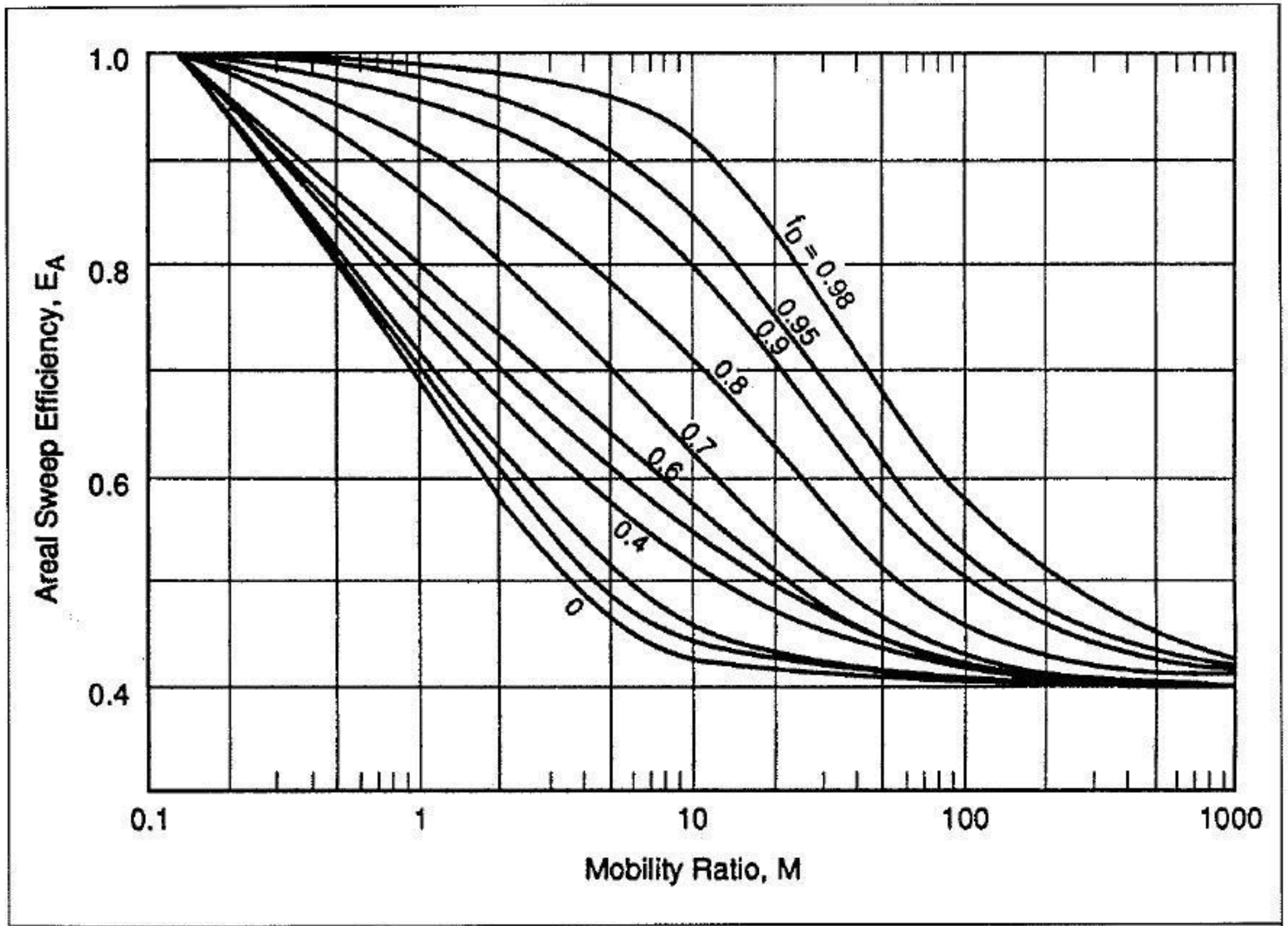


Fig. 4.10 gives E_A as a function of M for different values of the fractional flow of the displacing phase, f_D, at the producing well. As previously stated, production of the displaced phase is assumed to come entirely from the unswept region of the pattern.

f_D=WOR/(WOR+1)

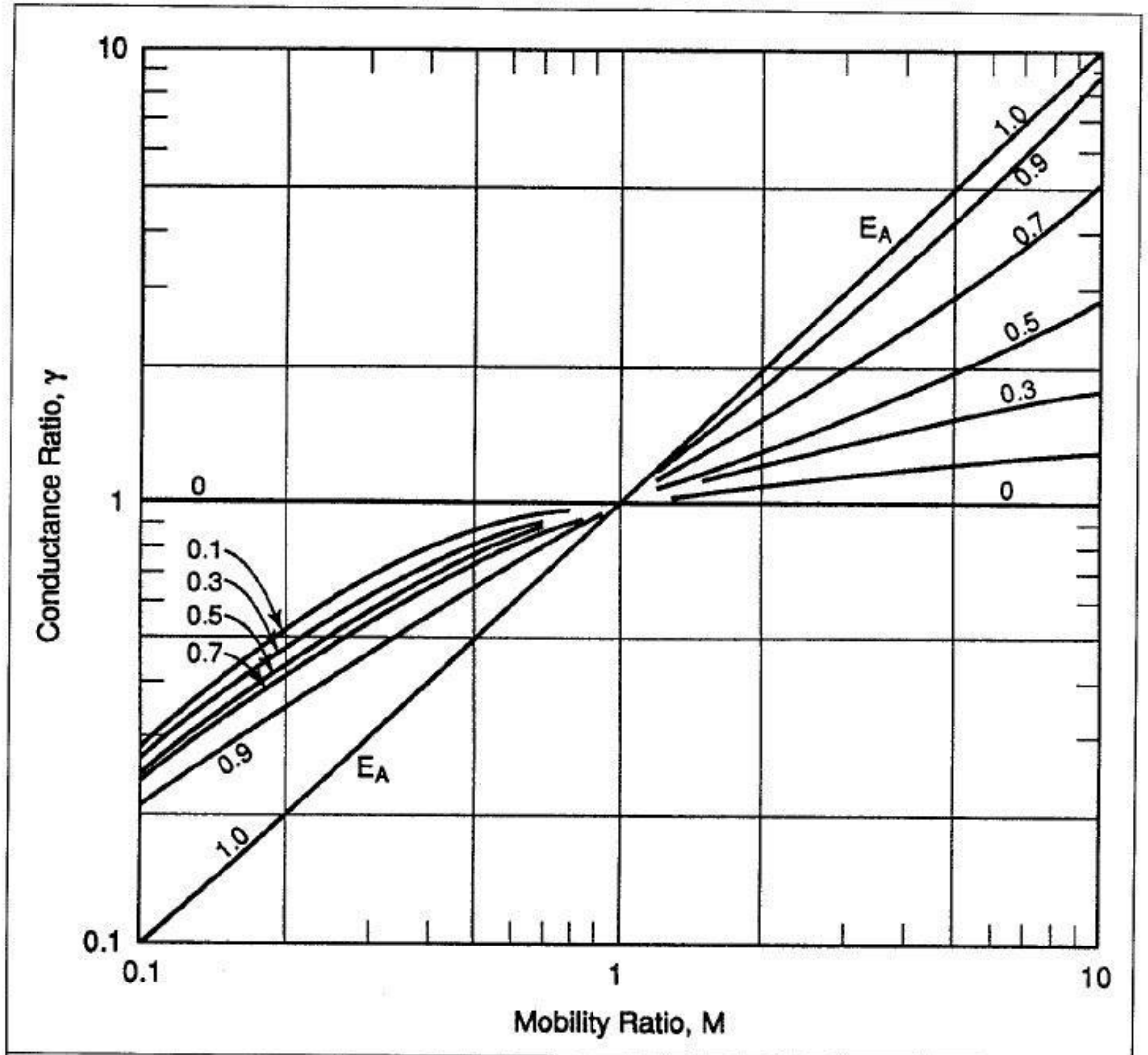


Areal sweep efficiency as a function of mobility ratio and fractional flow at displacing phase, five-spot pattern (from Caudle and Witte).

Prediction of areal displacement performance for five-spot pattern

Figure 3

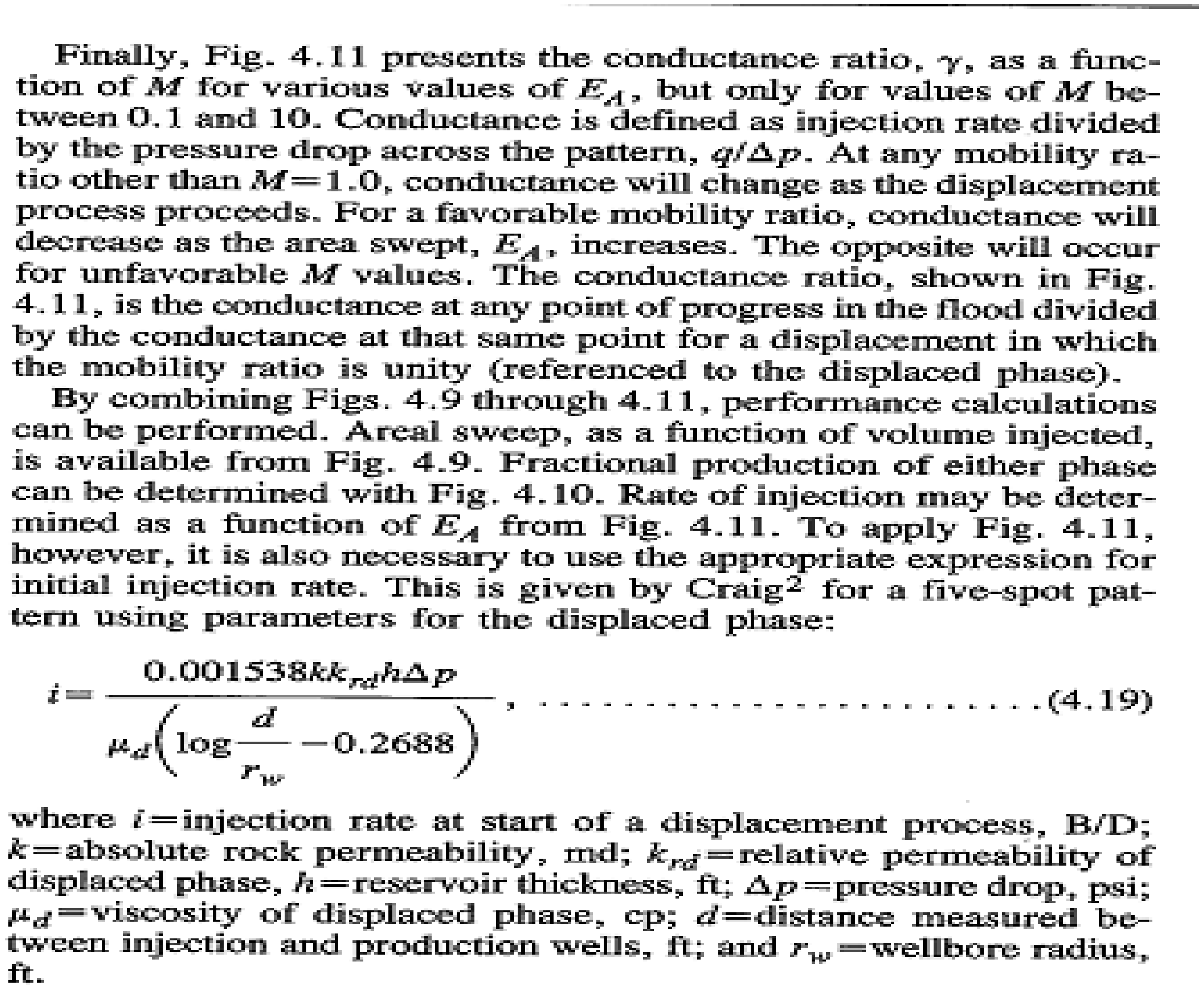
Gives conductance ratio, γ, as a function of M for various values of E_A. Conductance is defined as the ratio between injection rate to pressure drop, $q/\Delta P$.



Conductance ratio as a function of mobility ratio and areal sweep, five-spot pattern

Prediction of areal displacement performance for five-spot pattern

Figure 3



Finally, Fig. 4.11 presents the conductance ratio, γ, as a function of M for various values of E_A, but only for values of M between 0.1 and 10. Conductance is defined as injection rate divided by the pressure drop across the pattern, $q/\Delta p$. At any mobility ratio other than $M=1.0$, conductance will change as the displacement process proceeds. For a favorable mobility ratio, conductance will decrease as the area swept, E_A, increases. The opposite will occur for unfavorable M values. The conductance ratio, shown in Fig. 4.11, is the conductance at any point of progress in the flood divided by the conductance at that same point for a displacement in which the mobility ratio is unity (referenced to the displaced phase).

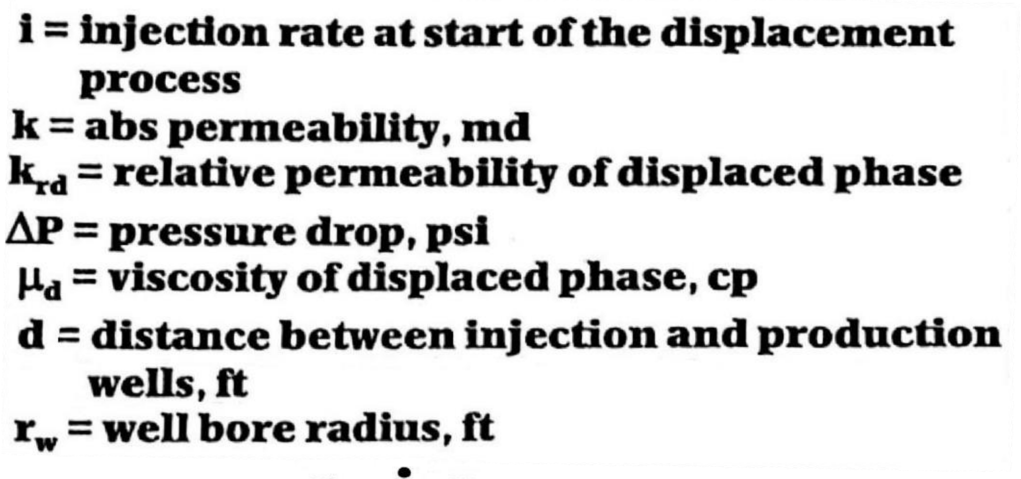
By combining Figs. 4.9 through 4.11, performance calculations can be performed. Areal sweep, as a function of volume injected, is available from Fig. 4.9. Fractional production of either phase can be determined with Fig. 4.10. Rate of injection may be determined as a function of E_A from Fig. 4.11. To apply Fig. 4.11, however, it is also necessary to use the appropriate expression for initial injection rate. This is given by Craig[2] for a five-spot pattern using parameters for the displaced phase:

$$i=\frac{0.001538kk_{rd}h\Delta p}{\mu_d\left(\log\frac{d}{r_w}-0.2688\right)}, \quad \text{.......................} (4.19)$$

where i=injection rate at start of a displacement process, B/D; k=absolute rock permeability, md; k_{rd}=relative permeability of displaced phase, h=reservoir thickness, ft; Δp=pressure drop, psi; μ_d=viscosity of displaced phase, cp; d=distance measured between injection and production wells, ft; and r_w=wellbore radius, ft.

To apply this figure, it is necessary to use the appropriate expression for initial injection rate. This is given by Craig for five-spot pattern as:

$$\mathbf{i} = \frac{0.001538 k \cdot k_{rd} \cdot h \cdot \Delta P}{\mu_d \left(\log \frac{d}{r_w} - 0.2688 \right)}$$



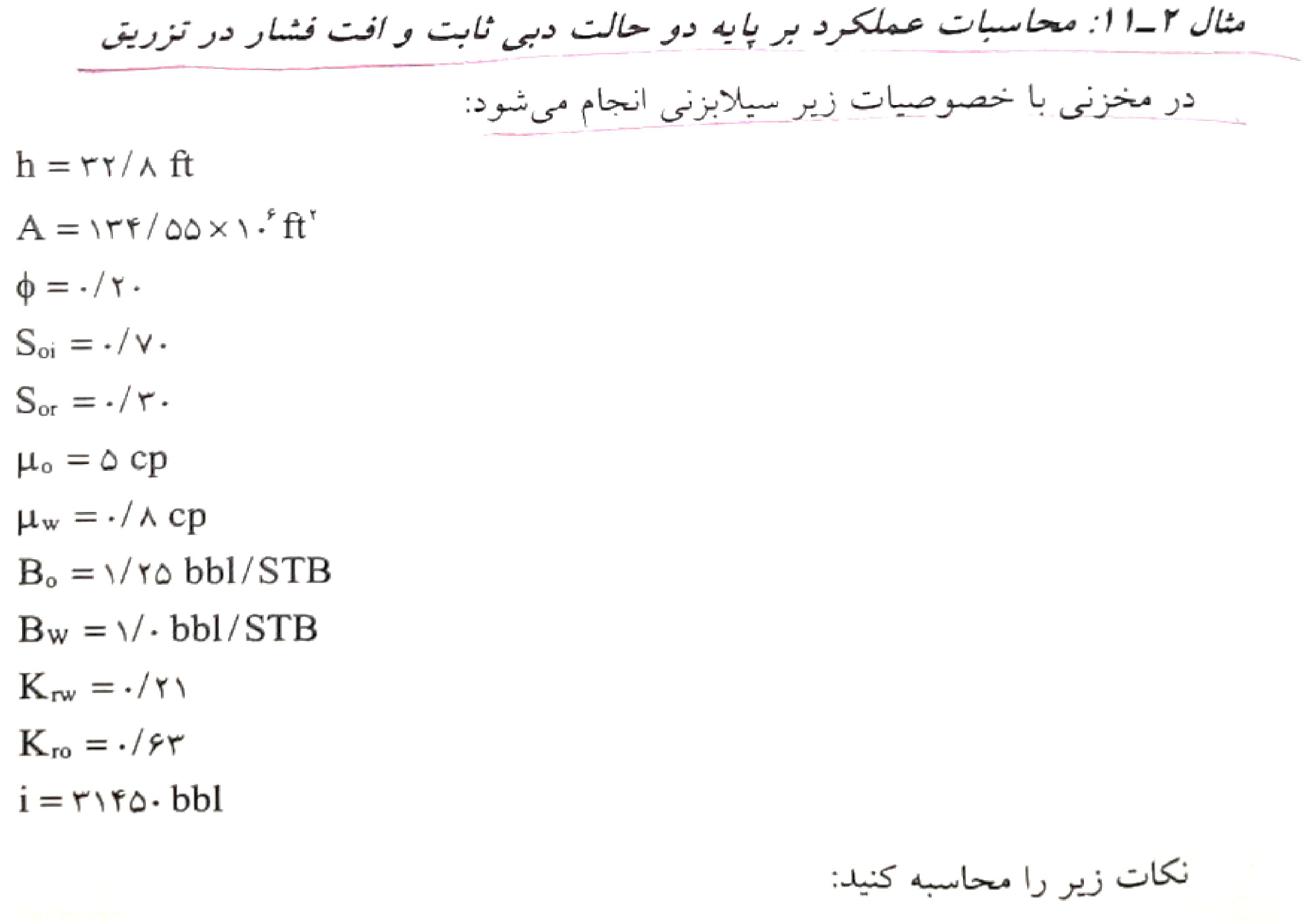
i = injection rate at start of the displacement process
k = abs permeability, md
k_{rd} = relative permeability of displaced phase
ΔP = pressure drop, psi
μ_d = viscosity of displaced phase, cp
d = distance between injection and production wells, ft
r_w = well bore radius, ft

$$\mathbf{q} = \mathbf{i} \cdot \gamma$$

At any point in the flood, the flow rate is given by:

q = total flow rate at any specific time in the displacement process. Where the total flow rate q at any time is equal to the injection rate and = production rate at that same point in time

Prediction of areal displacement performance for five-spot pattern



مثال ۲_۱۱: محاسبات عملکرد بر پایه دو حالت دبی ثابت و افت فشار در تزریق

در مخزنی با خصوصیات زیر سیلابزنی انجام می‌شود:

$h = ۳۲/۸\ \text{ft}$

$A = ۱۳۴/۵۵ \times ۱۰^{۶}\ \text{ft}^{۲}$

$\phi = ۰/۲۰$

$S_{oi} = ۰/۷۰$

$S_{or} = ۰/۳۰$

$\mu_o = ۵\ \text{cp}$

$\mu_w = ۰/۸\ \text{cp}$

$B_o = ۱/۲۵\ \text{bbl/STB}$

$B_w = ۱/۰\ \text{bbl/STB}$

$K_{rw} = ۰/۲۱$

$K_{ro} = ۰/۶۳$

$i = ۳۱۴۵۰\ \text{bbl}$

نکات زیر را محاسبه کنید:

۱ـ نفت تولیدی در زمان گسست؛

۲ـ نفت تولیدی در زمانی که $۱/۵V_{pd}$ آب تزریق می‌شود؛

۳ـ فشار تزریق در این دو زمان با فرض دبی ثابت ۲۰۰ STB/D و افت فشار اولیه ۱۰۰۰ psi؛

٤ـ دبی تزریق در این دو زمان با فرض فشار ثابت ۱۰۰۰ psi و دبی اولیه ۲۰۰ STB/D.

حل:

۱ـ نفت تولیدی در زمان گسست:

$$V_{pd} = A\phi h(S_{oi} - Sor) = ۱۳۴/۵۵ \times ۱۰^{۶} \times ۰/۲۰ \times ۳۲/۸(۰/۷۰ - ۰/۳) = ۳۵۳/۱ \times ۱۰^{۶}\,ft^{۲}$$

$$V_{pd} = ۳۵۳/۱ \times ۱۰^{۶}\,ft^{۲} \;/(۵/۶۱۵) = ۶۲/۹ \times ۱۰^{۶}\,bbl$$

$$M = (k_{rw}/\mu_w)/(k_{ro}/\mu_o) = (\frac{۰/۲۱}{۰/۸})/(\frac{۰/۶۳}{۵}) = ۲/۰۸$$

با این نسبت پویایی و در زمان گسست $(f_D = ۰)$ با توجه به شکل ۲ـ۳۹:

با این نسبت پویایی و در زمان گسست $(f_D = ۰)$ با توجه به شکل ۲ـ۳۹:

$E_A \approx ۰/۶$ = راندمان روبش

همچنین:

$$N_p = V_{pd} \times E_A / B_o$$

$$= (۶۲/۹ \times ۱۰^۶ \times ۰/۶)/(۱/۲۵)$$

$$= ۳۰/۱۹ \times ۱۰^۶ \text{STB}$$ نفت تولیدی

با توجه به این که دبی تزریق ثابت است، برای زمان گسست: دبی تزریق

$$t_{bt} = ۰/۶ V_{pd} / i$$

$$= ۰/۶ \times ۶۲/۹ \times ۱۰^۶ / ۳۱۴۵۰$$

$$= ۱۲۰۰ \text{ D}$$ روز

۲ـ نفت تولیدی وقتی $۱/۵V_{pd}$ آب تزریق شود:

با نسبت پویایی مورد نظر زمانی‌که $۱/۵V_{pd}$ تزریق شده است، با توجه به شکل ۲ـ۳۸:

$$E_A \approx ۰/۹$$

همچنین:

$$N_p = V_{pd} \times E_A / B_o$$

$$= (۶۲/۹ \times ۱۰^۶ \times ۰/۹)/(۱/۲۵)$$

$$= ۴۵/۲۹ \times ۱۰^۶ \mathrm{STB}$$

$$t = ۱/۵V_{pd} / i$$

$$= (۱/۵ \times ۶۲/۹ \times ۱۰^۶)/۳۱۴۵۰$$

$$= ۳۰۰۰ \mathrm{D}$$

می‌بینیم که بعد از زمان گسست نفت بسیار کمتری نسبت به آب تزریقی تولید می‌شود.

۳ـ فشار تزریق در دو زمان بالا با فرض دبی ثابت STB/D ۲۰۰ و افت فشار اولیه psi ۱۰۰۰.

با فرض دبی ثابت و در زمان گسست ($E_A = ۰/۶$)، با توجه به شکل ۲ـ۴۰:

$$\gamma = ۱/۴$$

$$\gamma = \frac{(q/\Delta p)}{(i/\Delta p)_1} \Rightarrow \Delta p = (\Delta p)_1/\gamma = ۱۰۰۰/(۱/۴) = ۷۱۴ \text{ psi}$$

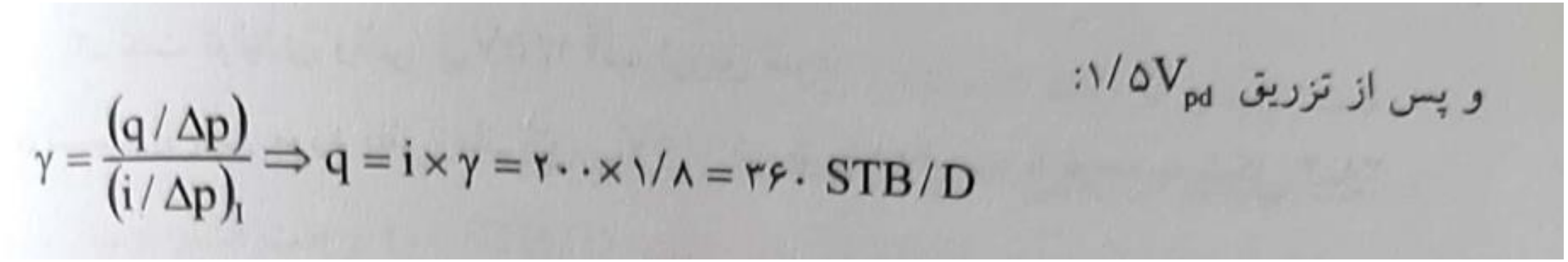
و پس از تزریق $۱/۵V_{pd}$ با توجه به شکل ۲ـ۴۰:

$$\gamma = ۱/۸$$

$$\Delta p = (\Delta p)_1/\gamma = ۱۰۰۰/(۱/۸) = ۵۵۶ \text{ psi}$$

۴ـ دبی تزریق در دو زمان بالا با فرض فشار ثابت psi ۱۰۰۰ و دبی اولیه مخزن ۲۰۰ STB/D:

$$\gamma = \frac{(q/\Delta p)}{(i/\Delta p)_1} \Rightarrow q = i \times \gamma = ۲۰۰ \times ۱/۴ = ۲۸۰ \text{ STB/D}$$



و پس از تزریق $۱/۵V_{pd}$:

$$\gamma = \frac{(q/\Delta p)}{(i/\Delta p)_1} \Rightarrow q = i \times \gamma = ۲۰۰ \times ۱/۸ = ۳۶۰ \text{ STB/D}$$

Example

A water flood is conducted in a five-spot pattern for which the pattern area is 20 acres (1 acre = 43560 ft^2). Reservoir properties are:

$h = 20ft$
$\varphi = 0.2$
$S_{oi} = 0.8$
$S_{or} = 0.25$
$\mu_o = 1$ cp
$\mu_w = 1$ cp
$B_o = 1$ RB/STB
$K = 50$ md
$K_{rw} = 0.27$ (at S_{or})
$K_{ro} = 0.94$ (at S_{iw})
$\Delta P = 1250$ psi
$R_w = 0.5$ ft

Use the correlation of Caudle and Witte to calculate:

1) The barrels of oil recovered at the point in time at which the producing WOR= 20
2) The volume of water injected at the same point

3) The rate of water injection at the same point
4) The initial rate of water injection at the start of water flood

solution

f_D=WOR/(WOR+1)

(1) Mobility ratio of the process and fractional flow at displacing phase are:

$$M=\left(\frac{k_{rw}}{\mu_w}\right)_{or}\cdot\left(\frac{\mu_o}{k_{ro}}\right)_{S_{iw}}=2.9 \qquad f_D=\frac{20}{21}=0.95$$

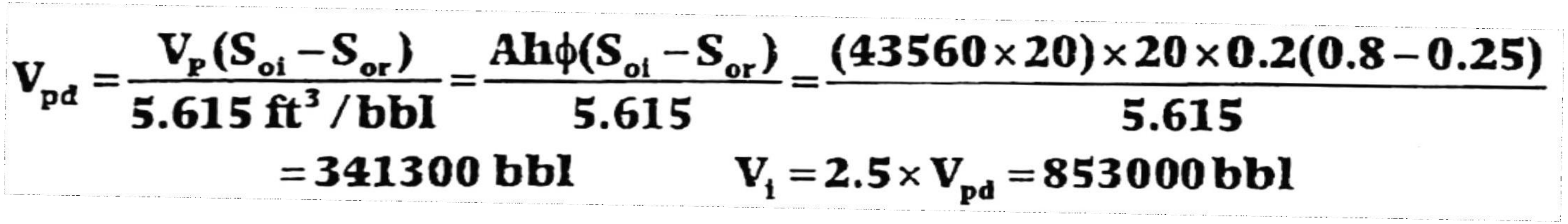
From Figure 2, E_A= 0.94.

From definition of E_A oil recovery is:

$$N_P=Ah\phi(S_{oi}-S_{or})E_A\times\frac{1}{5.615(ft^3/bbl)}\times\frac{1}{B_o}=$$

$$\frac{(43560\ ft^2/acre)\times 20\ acre\times 20\ ft\times 0.2(0.8-0.25)\times 0.94}{5.615\ ft^3/bbl\times 1\ RB/STB}=321,000\ STB$$

(2) From figure 1, calculate total water injected. Knowing M and E_A, figure 1 gives V_i/V_{pd}=2.5. Hence:



$$V_{pd}=\frac{V_P(S_{oi}-S_{or})}{5.615\ \text{ft}^3/\text{bbl}}=\frac{Ah\phi(S_{oi}-S_{or})}{5.615}=\frac{(43560\times 20)\times 20\times 0.2(0.8-0.25)}{5.615}$$

$$=341300\ \text{bbl} \qquad V_i=2.5\times V_{pd}=853000\,\text{bbl}$$

solution

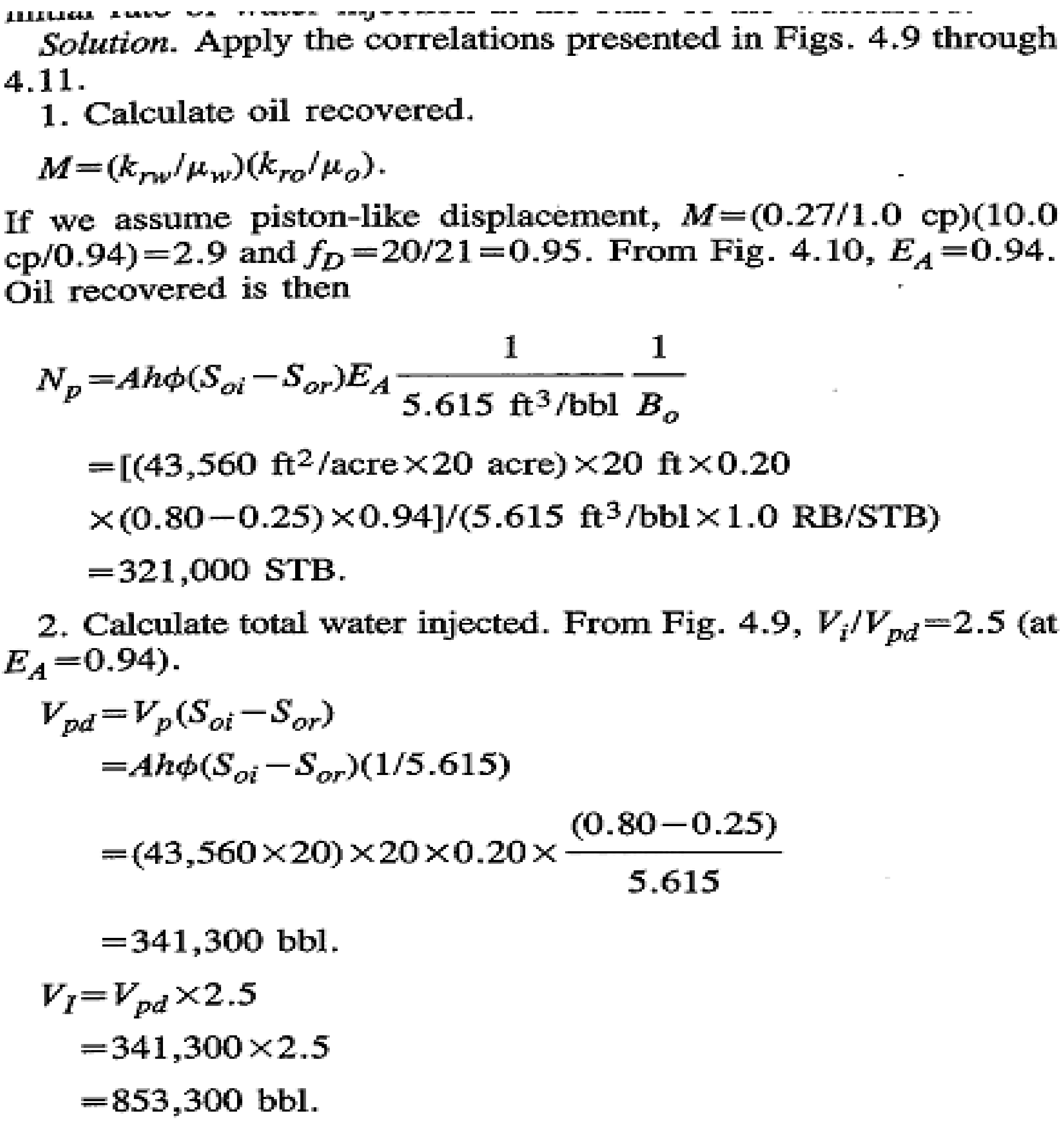
(3) Calculate water injection rate at the same point in time from:

$$i=\frac{0.001538kk_{ro}h\Delta P}{\mu_o\left(\log\frac{d}{r_w}-0.2688\right)}=\frac{0.001538\times 50\times 0.94\times 20\times 1250}{10\left(\log\frac{660}{0.5}-0.2688\right)}=63.4\ \text{B/D}$$

From figure 3, γ= 2.7, therefore, q= i×γ= 63.4×2.7= 171 B/D

(4) The initial water injection rate is the injection rate, i, calculated from the above equation given for I with the properties of the oil. This yields:

$$i = 63.4 \text{ B/D}$$



Solution. Apply the correlations presented in Figs. 4.9 through 4.11.

1. Calculate oil recovered.

$M=(k_{rw}/\mu_w)(k_{ro}/\mu_o)$.

If we assume piston-like displacement, $M=(0.27/1.0\text{ cp})(10.0\text{ cp}/0.94)=2.9$ and $f_D=20/21=0.95$. From Fig. 4.10, $E_A=0.94$. Oil recovered is then

$$N_p=Ah\phi(S_{oi}-S_{or})E_A\frac{1}{5.615\text{ ft}^3/\text{bbl}}\frac{1}{B_o}$$

$$=[(43{,}560\text{ ft}^2/\text{acre}\times 20\text{ acre})\times 20\text{ ft}\times 0.20$$

$$\times(0.80-0.25)\times 0.94]/(5.615\text{ ft}^3/\text{bbl}\times 1.0\text{ RB/STB})$$

$$=321{,}000\text{ STB}.$$

2. Calculate total water injected. From Fig. 4.9, $V_i/V_{pd}=2.5$ (at $E_A=0.94$).

$$V_{pd}=V_p(S_{oi}-S_{or})$$

$$=Ah\phi(S_{oi}-S_{or})(1/5.615)$$

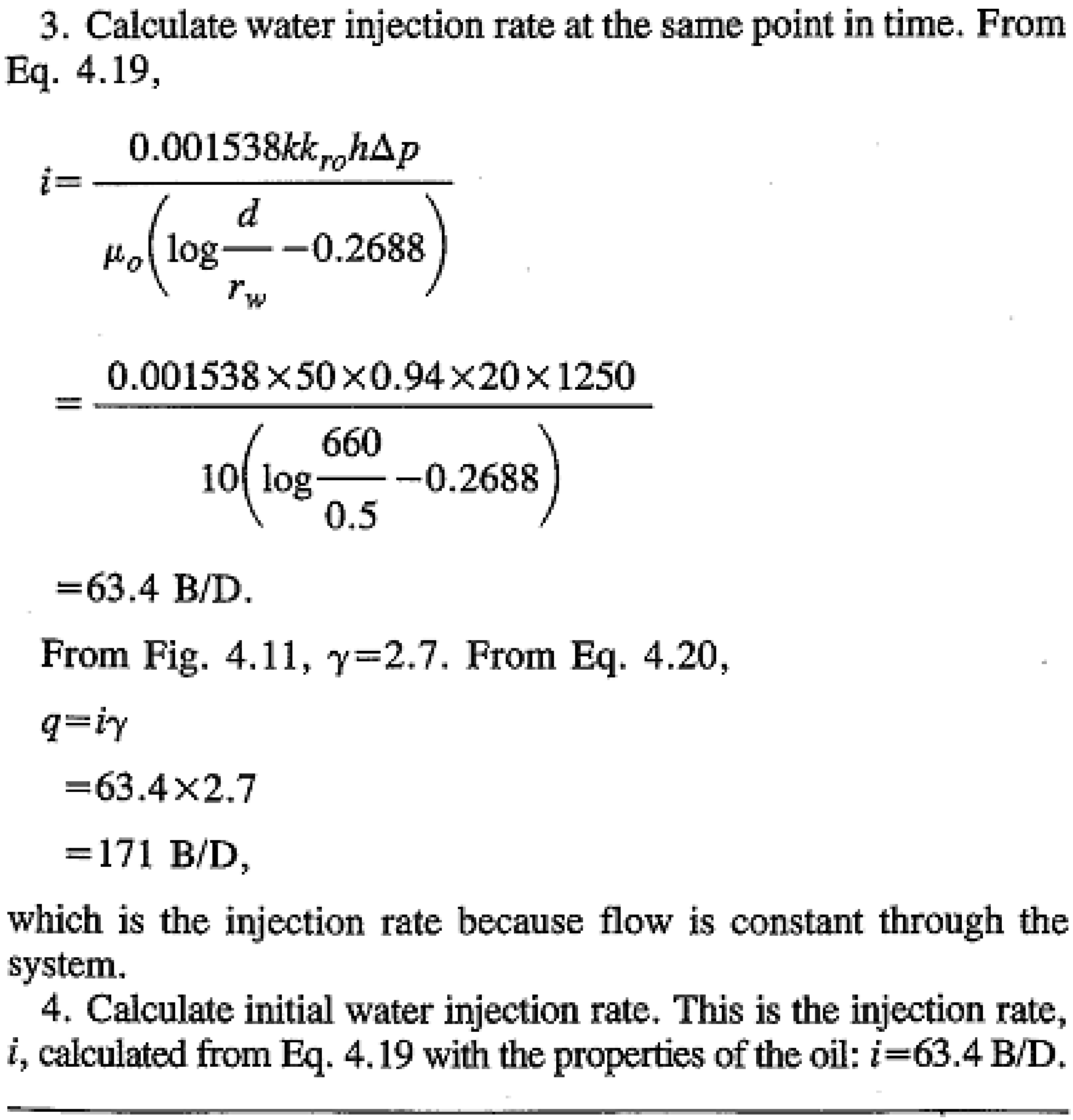
$$=(43{,}560\times 20)\times 20\times 0.20\times\frac{(0.80-0.25)}{5.615}$$

$$=341{,}300\text{ bbl}.$$

$$V_I=V_{pd}\times 2.5$$

$$=341{,}300\times 2.5$$

$$=853{,}300\text{ bbl}.$$



3. Calculate water injection rate at the same point in time. From Eq. 4.19,

$$i = \frac{0.001538 k k_{ro} h \Delta p}{\mu_o \left(\log \frac{d}{r_w} - 0.2688 \right)}$$

$$= \frac{0.001538 \times 50 \times 0.94 \times 20 \times 1250}{10 \left(\log \frac{660}{0.5} - 0.2688 \right)}$$

$$= 63.4 \text{ B/D.}$$

From Fig. 4.11, $\gamma = 2.7$. From Eq. 4.20,

$$q = i\gamma$$

$$= 63.4 \times 2.7$$

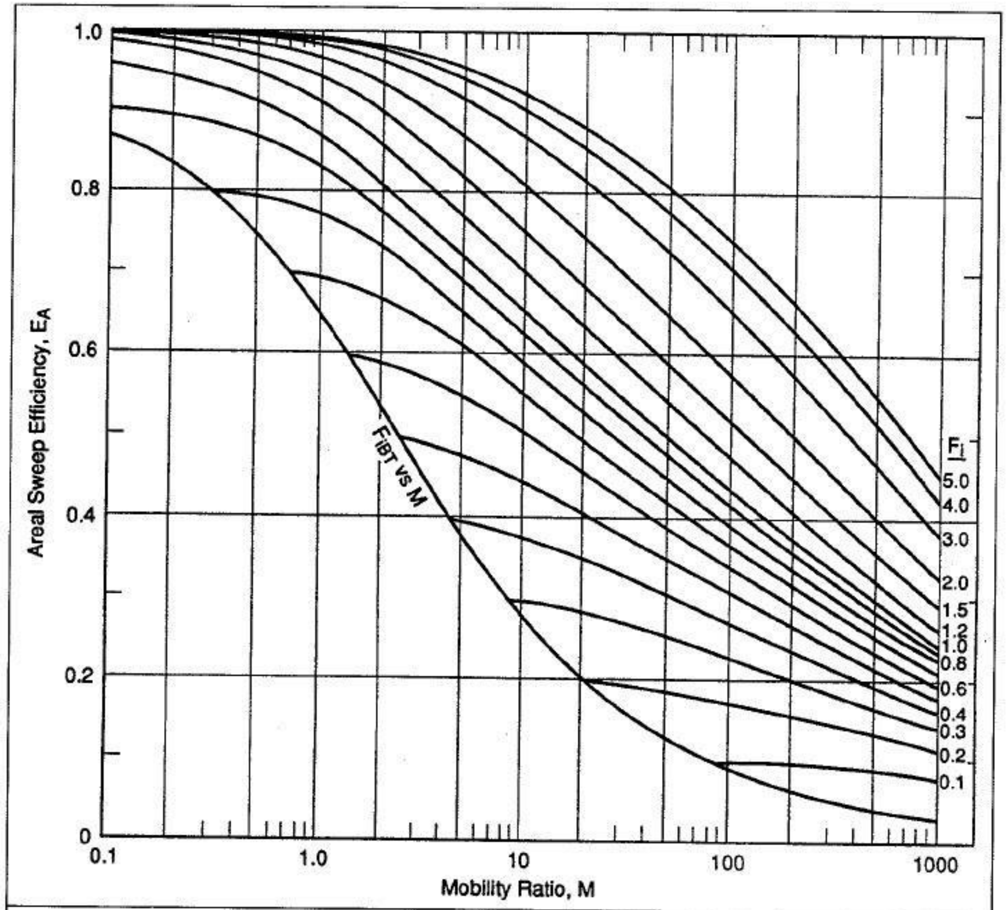
$$= 171 \text{ B/D,}$$

which is the injection rate because flow is constant through the system.

4. Calculate initial water injection rate. This is the injection rate, i, calculated from Eq. 4.19 with the properties of the oil: $i = 63.4$ B/D.

Prediction of areal displacement performance for five-spot pattern

Claridge correlation for miscible displacement



Claridge correlation for areal sweep efficiency (from Claridge).