Fractured reservoirs

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Lecture outline:

- Introduction.
- Geology of fractured reservoirs and fracture evaluation.
- Flow in fractured networks. Porosity and permeability.
- The imbibition and drainage process in fractured systems
- Production mechanisms and oil recovery efficiency in fractured reservoirs
- Special simulation problems related to fractured reservoirs.
- Field examples

Supplementary material:

Van Golf-Racht: ”Fundamentals of fractured reservoir engineering”, Elsevier, Amsterdam 1982.

R.Aguilera: ”Naturally fractured reservoirs”, PenWellBooks, Tulsa 1980.

L.H. Reiss: ”The reservoir engineering aspects of fractured formations”, technip, Paris, 1980.

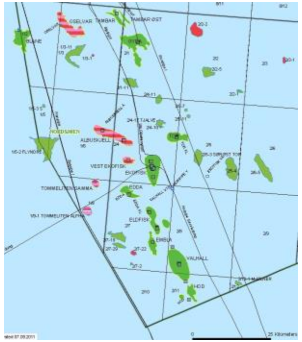
R.A. Nelson: ”Geological analysis of naturally fractured reservoirs” Gulf Publishing, Boston, 2001.

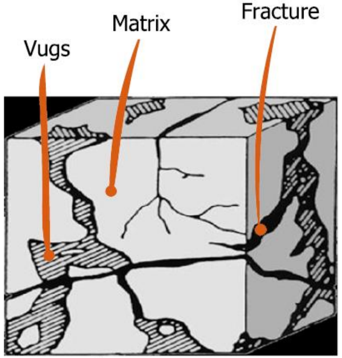
W. Narr, D.W. Schechter, L.B. Thompson: ”Naturally Fractured Reservoir Characterization”, SPE,2006.

S.M.Skjæveland and O.K. Siqveland: “North Sea Chalk. JCR-7 Monograph”. November, 2017

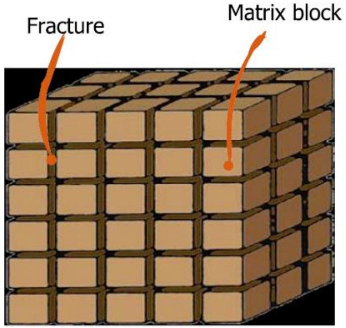
Introduction

- Some of the largest fields in the world are fractured. Examples:
  - Iran (Haft Kel, Ain Zalah)
  - Iraq (Kirkuk)
  - U.S. (Sprawberry, Yates)
  - Italy (val d'Agri)
  - France (Lacq)
  - Africa
  - North Sea chalk fields (Ekofisk, Valhall,…)
- Single continuum description is not adequate for modeling (or reservoir engineering calculations)
- We often refer to fractured media as "dual porosity", 'dual permeability" or in general "complex media".





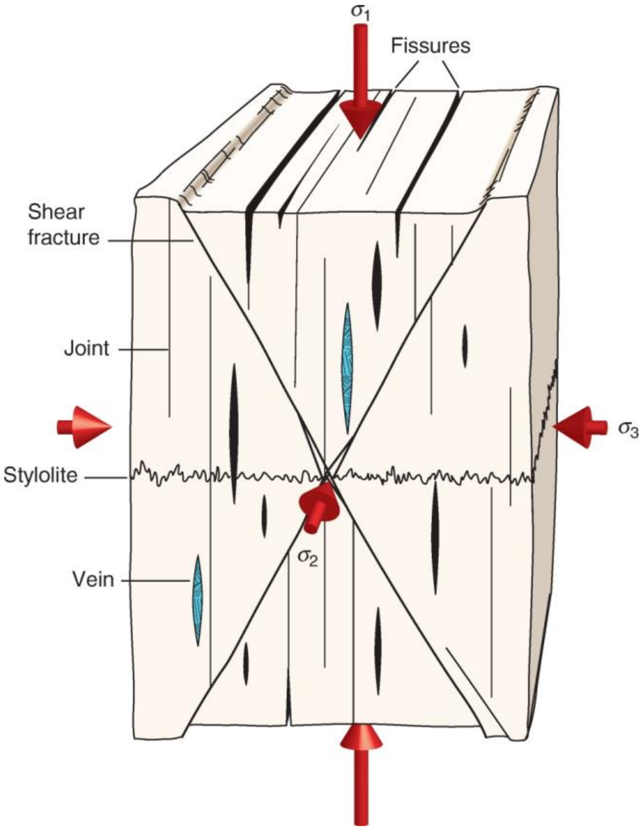
Actual reservoir



Model reservoir

Introduction

- Many reservoirs in the world are fractured to various degrees
- Fracturing occurred mostly in geological time due to
  - Tensile failure (on the crest of a structure)
  - Shear fracturing and faulting
- Complex structure results especially in carbonate reservoirs (stylolites and joints)
- Fracture networks are usually highly conductive.



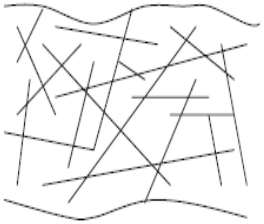
Identification

- A fractured reservoir is defined as being fractured only if a continuous network of fractures is distributed throughout the reservoir. Such fractures are formed naturally during specific geological circumstances of the reservoir history.

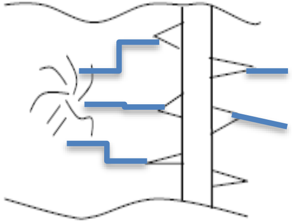
- The presence of dispersed fractures induced by engineering stimulations does not transform a reservoir into a naturally "fractured reservoir".

- A continuous fracture network in reservoirs is normally identified from:

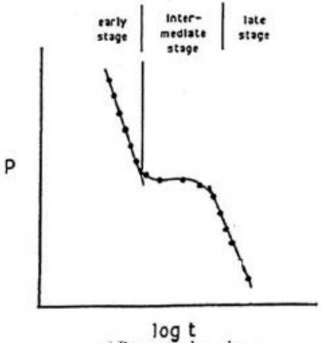
   1. Significant mud losses during drilling
   2. Special behavior of transient pressure analysis (double slope curves)
   3. core analysis, etc.



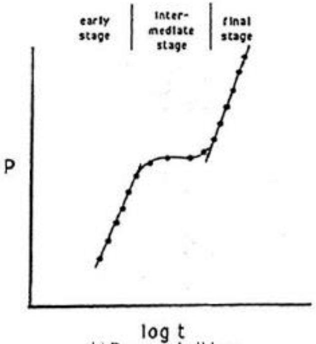
a) naturally fractured



b) artificially fractured

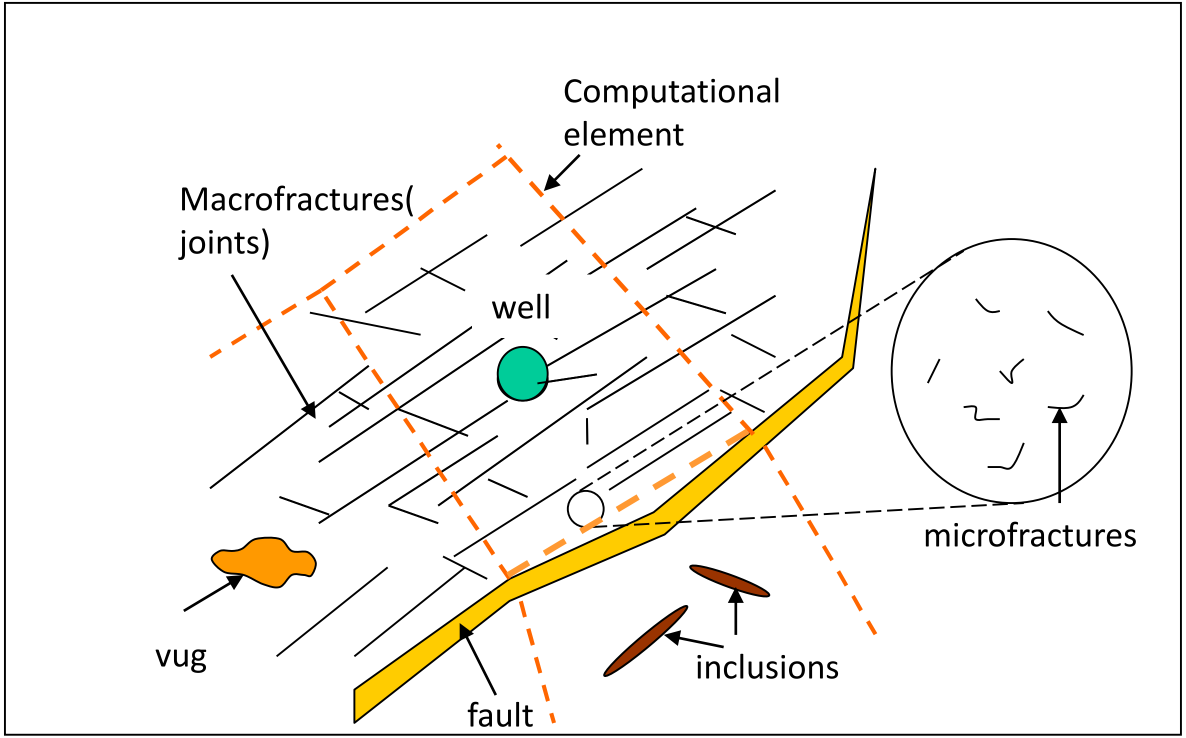


a) Pressure drawdown



b) Pressure build-up

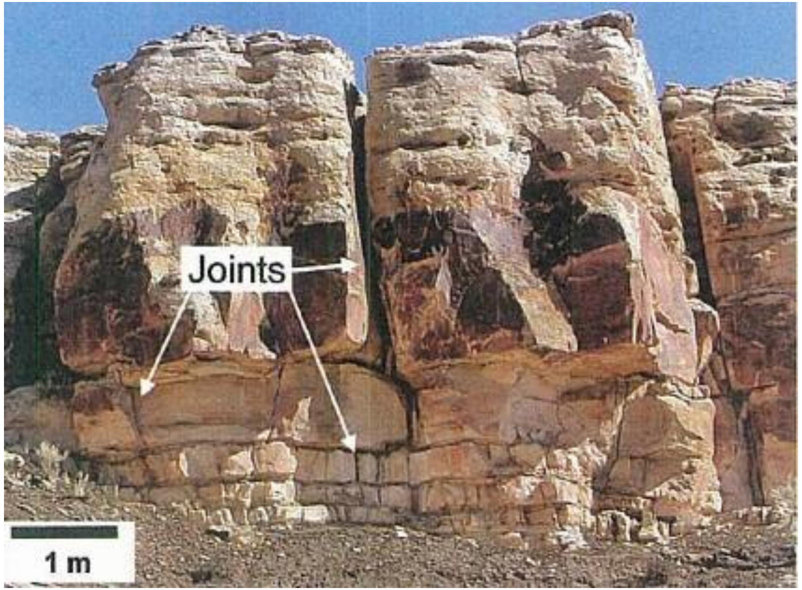
Fractured (complex) media: features of many different scales may exist in the field



Definitions

Fracture Term	Definition	Identifying Characteristics, Emphasizing Borehole-Based Evidence
Fracture	Discontinuity caused by brittle failure. All the features defined in this table are fractures.	Distinct discontinuity that post-dates formation of the rock.
Crack	Individual, isolated fracture showing no shearing offset. May be natural or induced.	Isolated (not necessarily part of a set). No shear offset.
Joint	One of a group (set) of naturally occuring spaced, parallel fractures showing no shearing offset. In stratified rock, joints are usually at a high angle to layering. Joint sets are extensive. Multiple joint sets form a "joint system."	No shear offset. At high angle to bedding in sedimentary rocks. With parallel fractures forms a set.
Fault	Naturally occurring fracture along which opposite sides have been displaced parallel to the fracture surface.	Shear offset. Fault-induced deformation adjacent to fault.

Fractures in sandstone

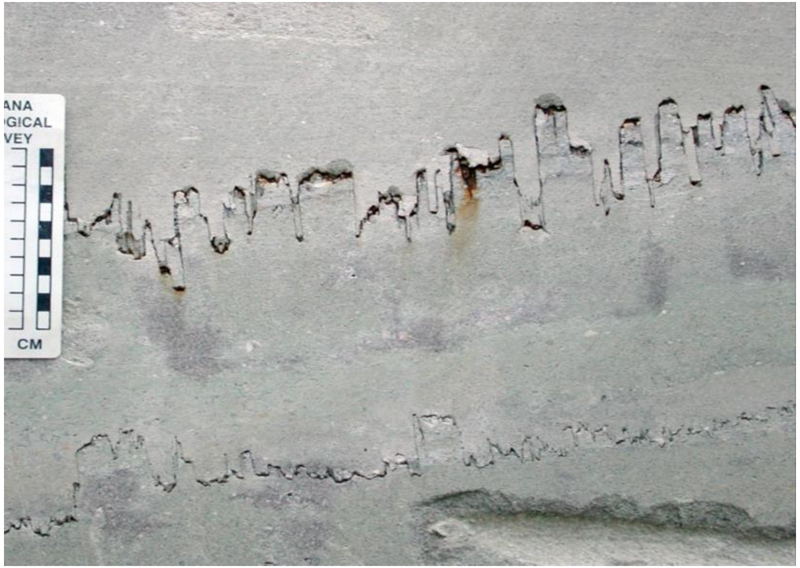


From Narr et al (2006)

Geological outcrop (chalk)

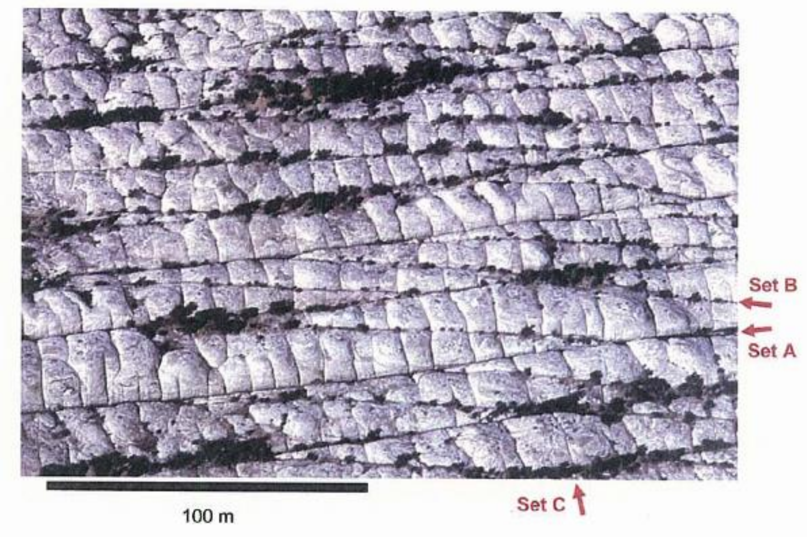
Stylolite

- A stylolite is an irregular discontinuity or non-structural fracture in limestone/dolomite and other sedimentary rocks.
- Stylolites result from compaction and dissolution during diagenesis.
- Stylolites appear as discontinuities in the rock and are often lined with insoluble clays.
- The stylolites may be a flow channel, but may also act as barriers.
- The term stylolite is derived from the Greek for pillar, stylo.



Fracture network

- Fracture system: a set of parallel fractures
- Fracture network: two or several associated fracture systems

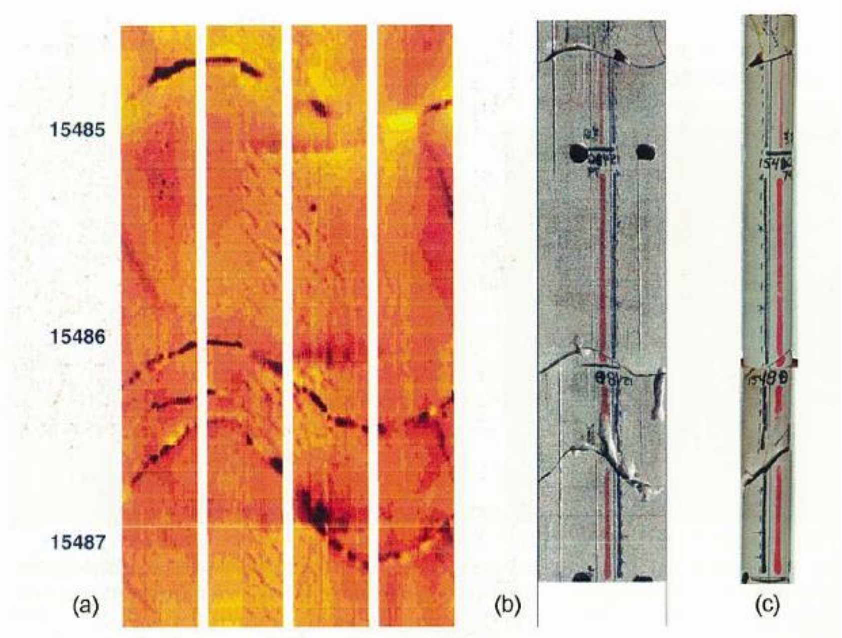


From Narr et al (2006)

Characterizing fractures at the well

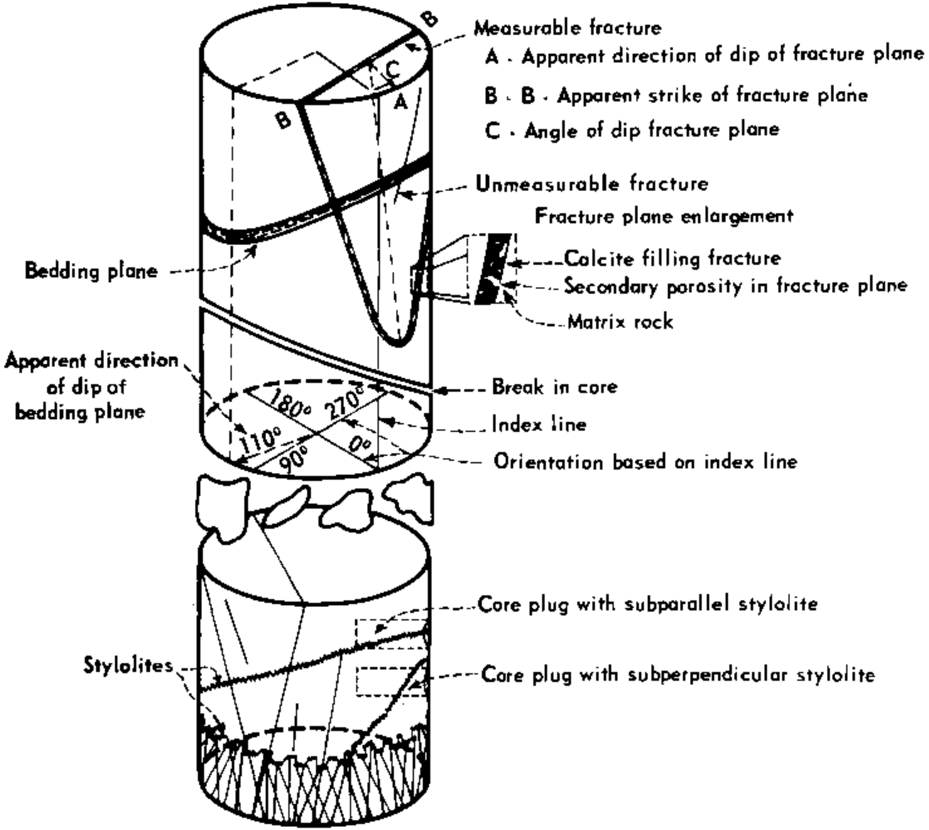
- Core
  - Are the fractures affected by diagenesis?
  - Is calcite plugging the fractures?

- Open Hole Logs
  - Electrical borehole image logs
    - Orientation of fractures
    - Number and spacing of fractures
    - Aperture (width) of fractures
  - Standard logs and cores



a) Resistivity image log,
b) Unwrapped image of the core,
c) Image of the core

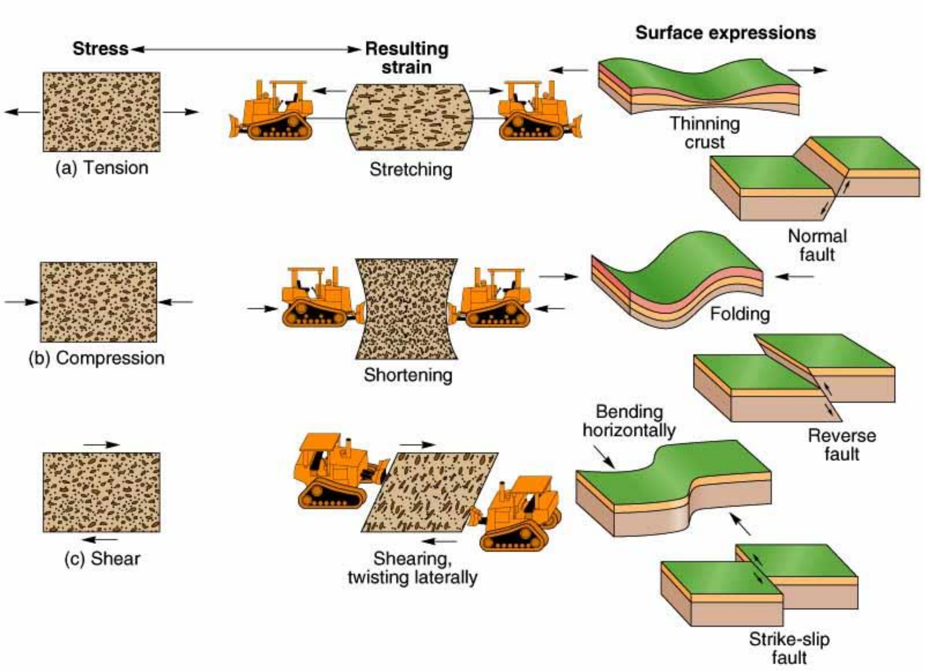
Fractured (complex) media: features that exist in a core



Note: fractures and other features can be created also by the coring operation and core handling!

Interwell Characterization
Mega - Geological Processes

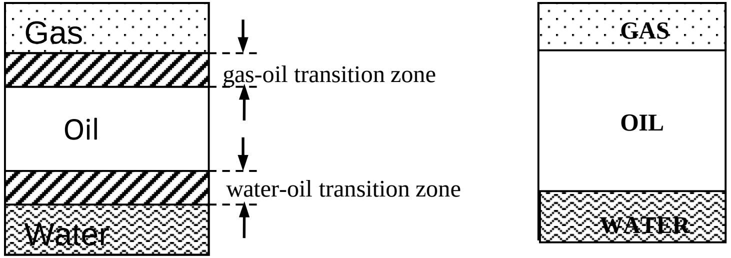
- Normally look at faulting first, then natural fracture development as they may be related
- Are the naturally fractures near faults?
- Is there a curvature aspect of the fractures?
  - Brittle rocks may break when bent by tectonic forces
  - Curvature related to maximum strain (and possibility of rock failure)
- What does the geologist think ?



Features of naturally fractured reservoirs

Other specific features that are used to confirm fractured reservoirs include the following:

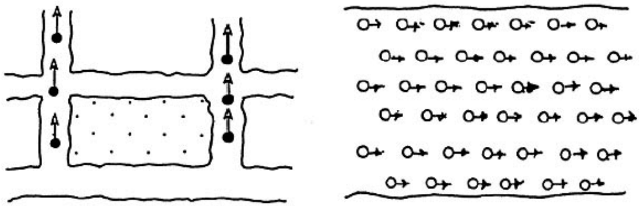
- Absence of the transition zone



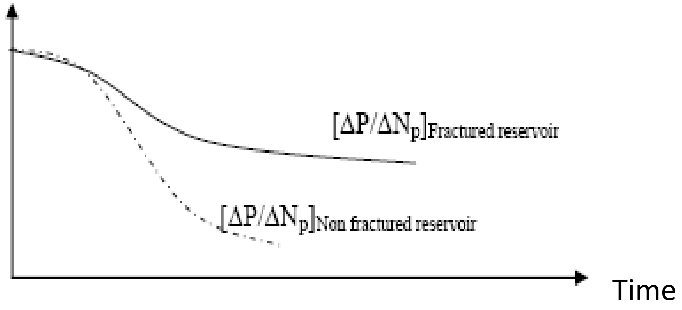
Conventional

Fractured

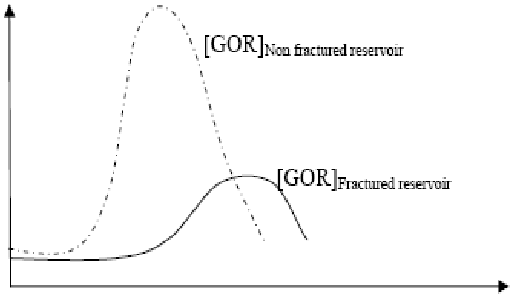
- Constant PVT properties with depth
- A small pressure drop around a producing well
- A fracture net-work gas-cap



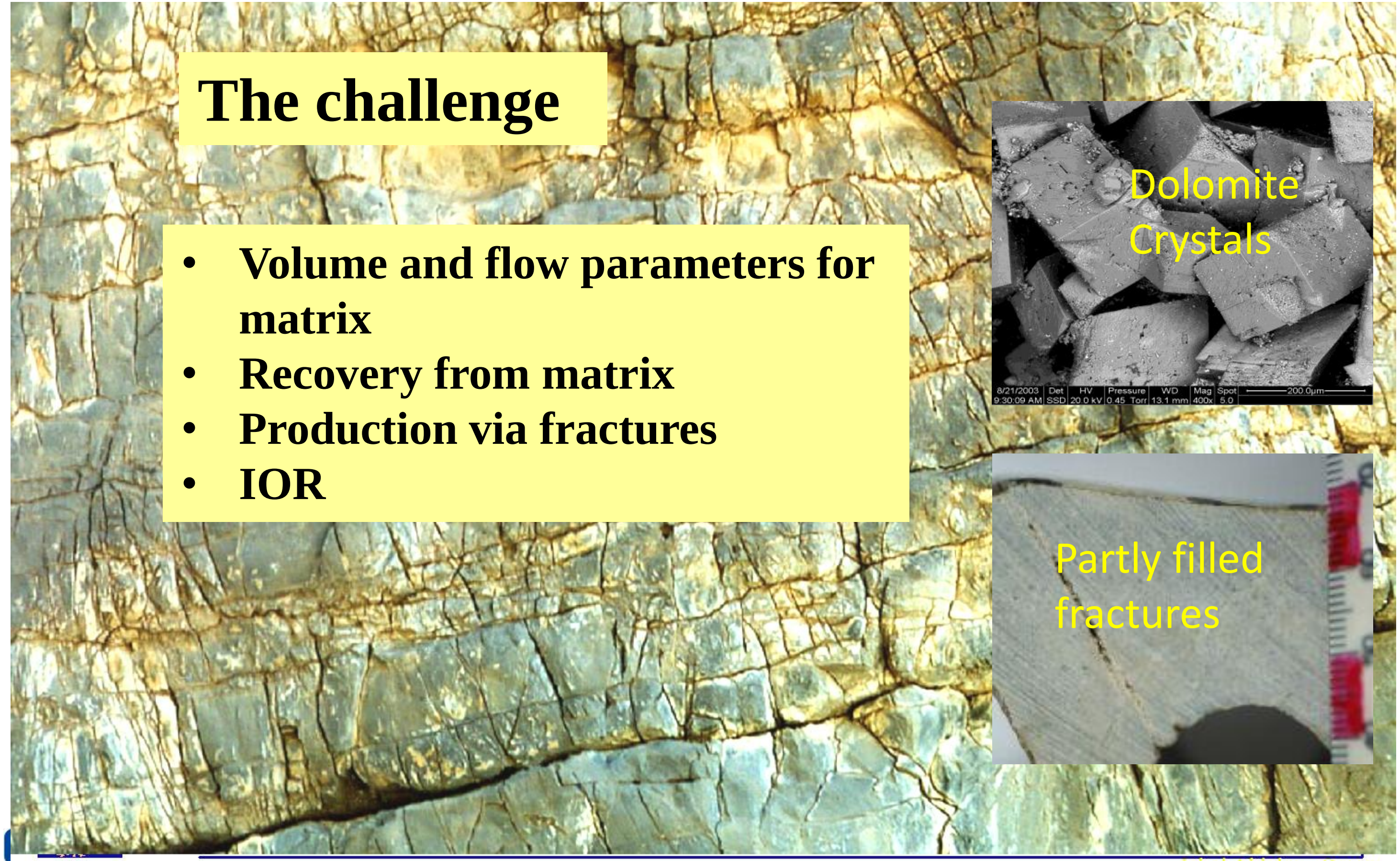
- Low rate of pressure decline per unit oil produced below bubble point pressure.



- Low reservoir gas-oil ratio (GOR).



Fluid flow in fractured media



The challenge

- Volume and flow parameters for matrix
- Recovery from matrix
- Production via fractures
- IOR

Jabal Akhdar - Oman

Porosity of fractured media

Primary (intergranular) ϕ_1

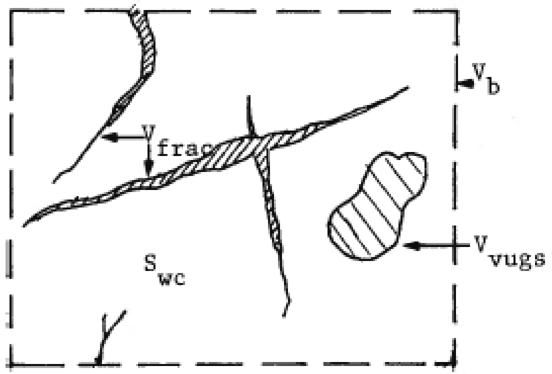
Secondary (fractures and vugs) ϕ_2

Total porosity = $\phi_1 + \phi_2$

$\phi_1 = V_{pore,m} / V_b$

$\phi_2 = (V_{frac} + V_{vugs}) / V_b$

Measured is usually matrix porosity $\phi_m = V_{pore,m} / V_{b,m}$. Then



$\phi_1 \cong (1 - \phi_2)\, \phi_m$

Porosity of fractured media

- Fracture porosity ranges:
  - Macrofracture networks ……..0.01-0.5 %
  - Isolated fissures …………….. 0.001-0.01%
  - Fissure networks ……………. 0.01-2%
  - Vugs ………………………….. 0.1-3%

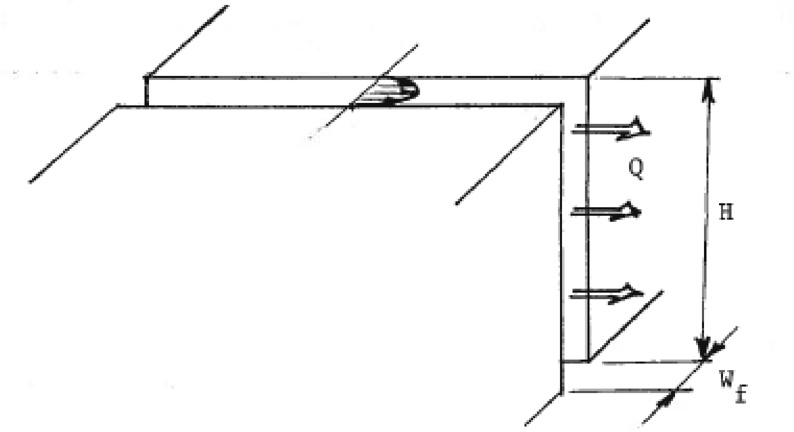
- Therefore:
  - for fluid storage frac porosity is usually not important
  - Most of the reserves are usually in the matrix

Fracture Permeability

- Intrinsic – related to fracture width (or flow area)

$k_{ff} = W_f^2/12$

$Q = W_f \, H \, (k_{ff}/\mu) \, (\Delta p/\Delta L)$



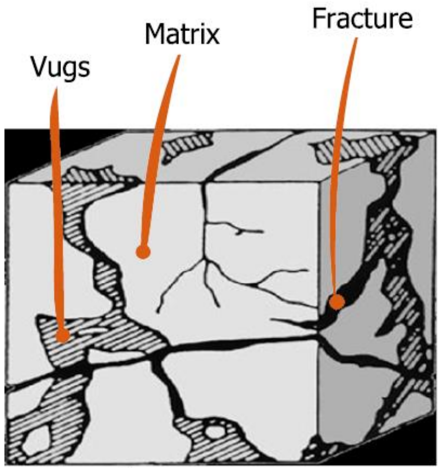
Assumptions:

-Laminar flow

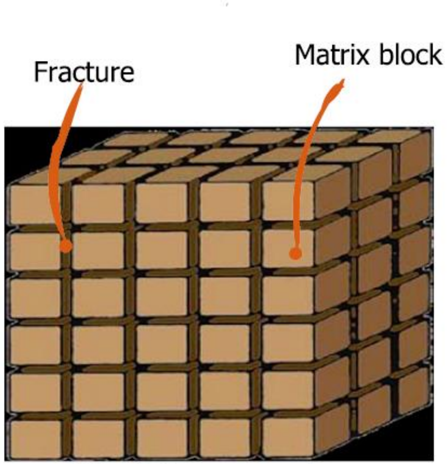
-Smooth parallel walls

Fracture networks

- For theoretical analysis and simulation, random fracture networks are replaced by regular networks of geometrically identical elements.
- This allows easy computations of properties
- Example – Warren and Root idealization

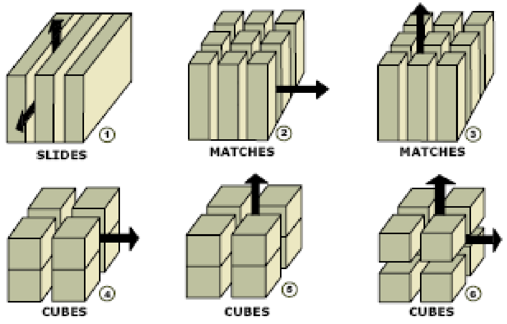


Actual reservoir



Model reservoir

Porosity and permeability for idealized systems



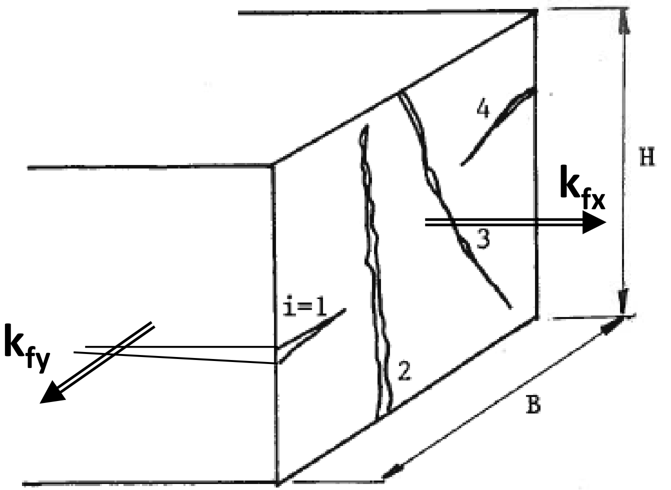
	Model	Dimensionless Equations			
	Type	LFD	ϕ_f	$K_f(\phi_f,a)$	$K_f(\phi_f,b)$
1	Slides	1/a	b/a	$1/12a^2\,\phi_f^3$	$1/12b^2\,\phi_f$
2	Matches	1/a	2b/a	$1/96a^2\,\phi_f^3$	$1/24b^2\,\phi_f$
3		2/a	2b/a	$1/48a^2\,\phi_f^3$	$1/12b^2\,\phi_f$
4	Cubes	1/a	2b/a	$1/96a^2\,\phi_f^3$	$1/12b^2\,\phi_f$
5		2/a	2b/a	$1/48a^2\,\phi_f^3$	$1/12b^2\,\phi_f$
6		2/a	3b/a	$1/162a^2\,\phi_f^3$	$1/18b^2\,\phi_f$

a - side dimension
b - fracture width
LFD - linear fracture density

Fracture Permeability

- Apparent (effective, or conventional) – related to bulk flow area

$$k_f = \Sigma\, k_{ffi}\, A_{fi} / A_{bulk} = \Sigma\, k_{ffi}\, A_{fi} / (H\, B)$$



Apparent permeability is used in simulators. It depends on:

-Individual fracture permeability

-Fracture density (no of fractures / area)

Can be strongly anisotropic

Other effects on fracture flow

- Turbulence – changes the flow resistance. Critical Reynolds number for flow in a slot is Re ~ 600, where

$$Re = (\rho v \, 2 \, W_f / \mu)$$

- Roughness of the walls – increases flow resistance.

- Tortuosity of the flow path

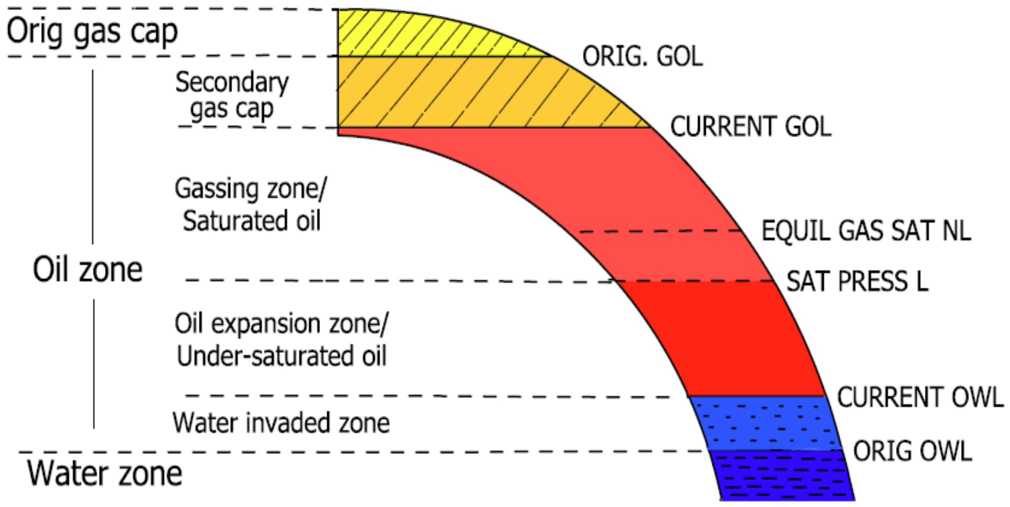
These effects reduce the fracture permeability; therefore the prediction using the $W^2/12$ is always optimistic (typically by an order of magnitude).

Because of these uncertainties, fracture permeability is typically a history matching parameter

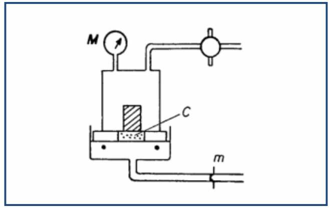
Matrix-fracture fluid exchange

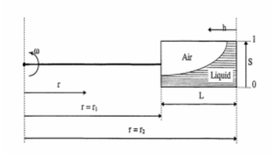
- The matrix-fracture fluid exchange depends on:
  - Rock / fluid characteristics.
  - Fluid types and saturation in matrix.
  - Fluid types and saturation in fractures.
  - Driving forces (gravity and/or capillarity)

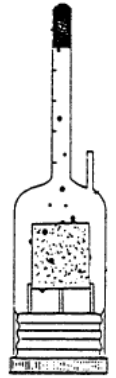
- Recovery versus time is an important relationship describing matrix-fracture fluid exchange.

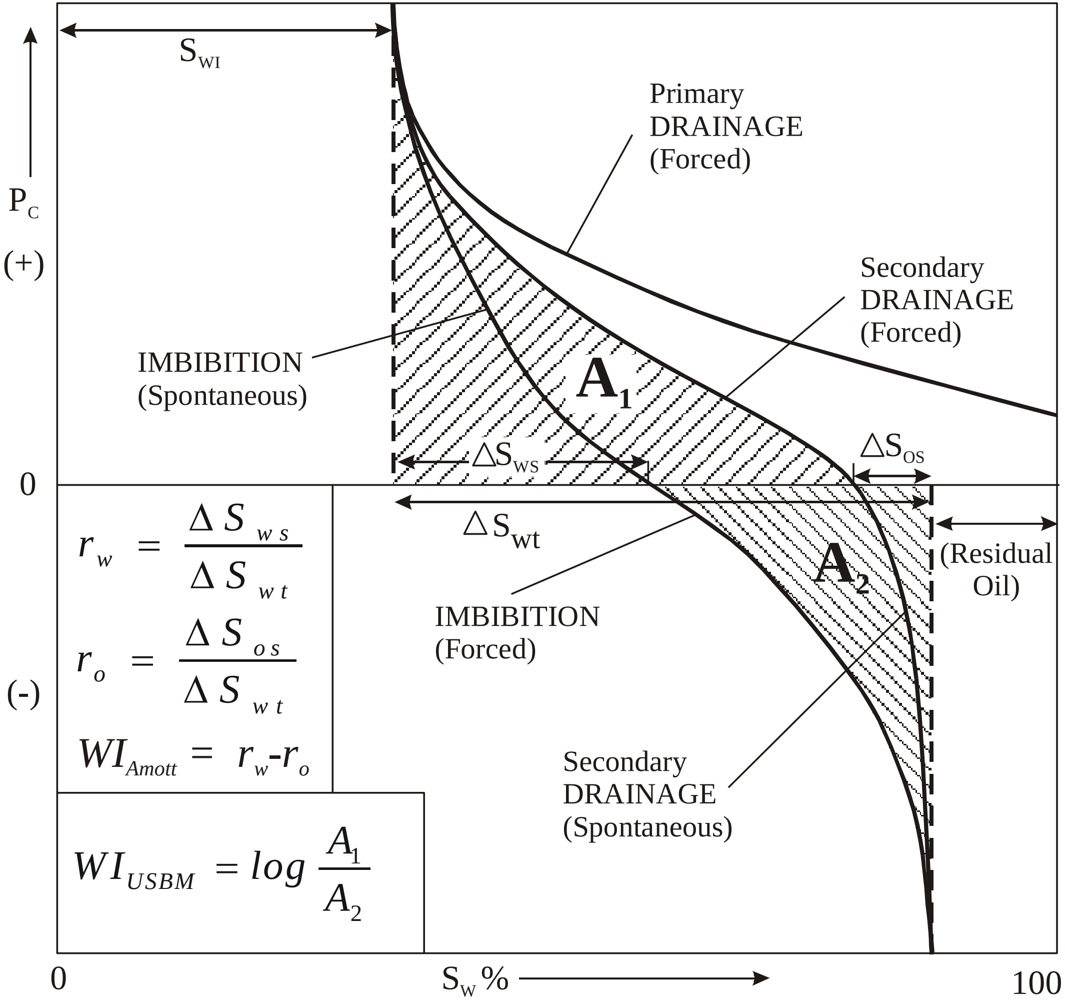


Water-oil capillary pressure versus saturation





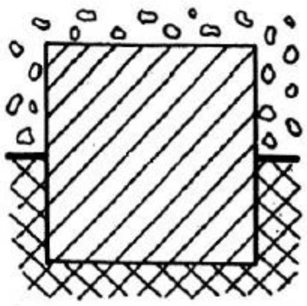




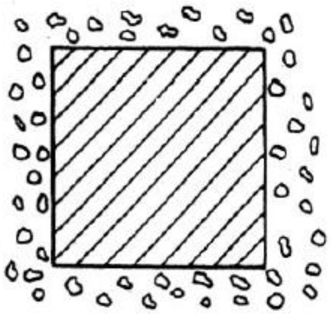
Matrix block saturated with oil.

Surrounding fractures partially and totally saturated with gas.

Partially invaded with gas

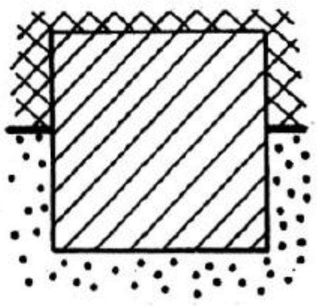


Totally invaded with gas

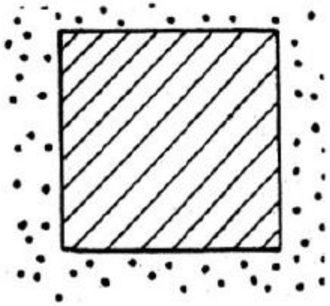


Matrix block saturated with oil.
Surrounding fractures partially and totally saturated with water.

Fractures partially saturated with water



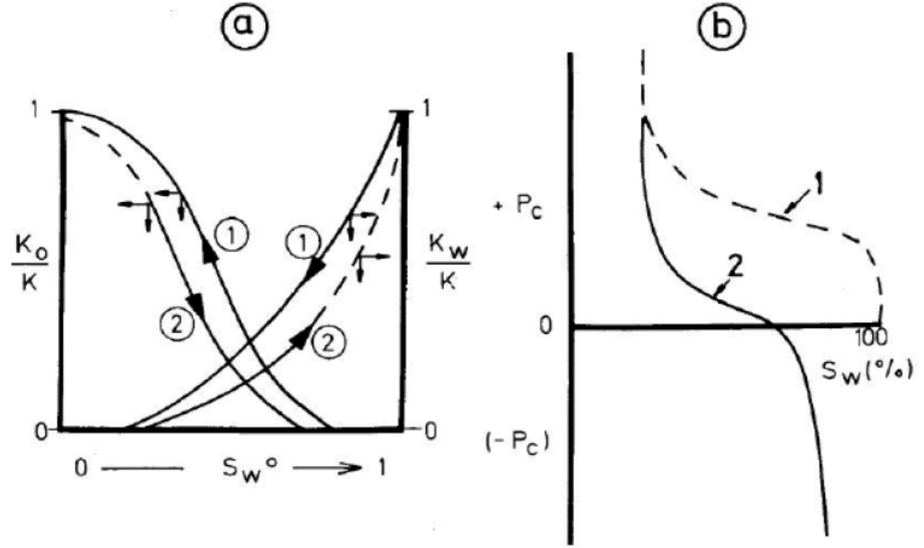
Fractures totally saturated with water



Displacement type and respective displacement history

Case	Fluid Saturation		Wetting phase in matrix	Oil Displacement Process	Displacement History
	Matrix Block	Fracture Network			
1	Oil	Water	Water	Imbibition	Reservoir production
2	Oil	Water	Oil	Drainage	Reservoir production
3	Oil	Gas	Oil	Drainage	Reservoir production
4	Gas	Water	Water	Imbibition	Reservoir production
5	Water	Oil	Water	Drainage	Reservoir migration
6	Water	Gas	Water	Drainage	Reservoir migration

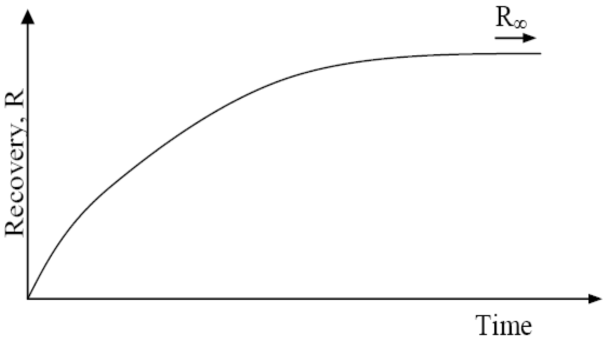
Rel perm and capillary pressure (drainage and imbibition)



Empirical approach

Aronofsky's model:

$$R = R_{\infty}(1 - e^{-\beta t})$$

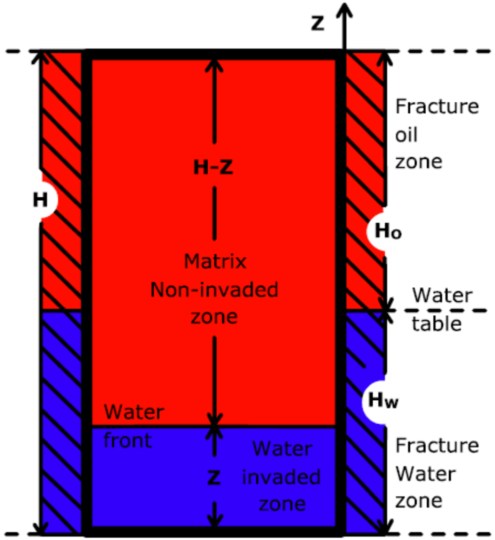


Driving mechanisms

The imbibition process can be governed by both gravity and capillary forces or only by one of them.

In the following we consider a theoretical study of a simplified system of a core sample with closed side walls.

Matrix block element, 1D flow

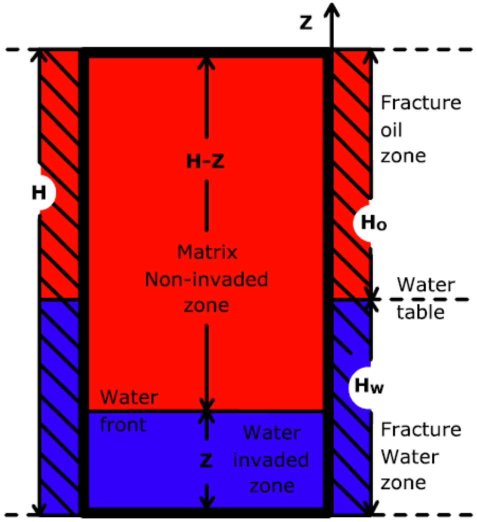


The matrix block is assumed as a cylinder where lateral walls are coated, so that fluid exchange will take place only through the lower or the upper face of the block.

The "water-table" could rise at a given height (H_W), which correspond to a fracture oil height (H_O) so that the block height can be expressed as; $H_{block} = H_W + H_O$

$$R = A \cdot z \cdot \phi_{eff} = A \cdot z \cdot \phi \cdot \Delta S_o = A \cdot z \cdot \phi \cdot (1 - S_{wi} - S_{or,imb})$$

Forces governing the flow



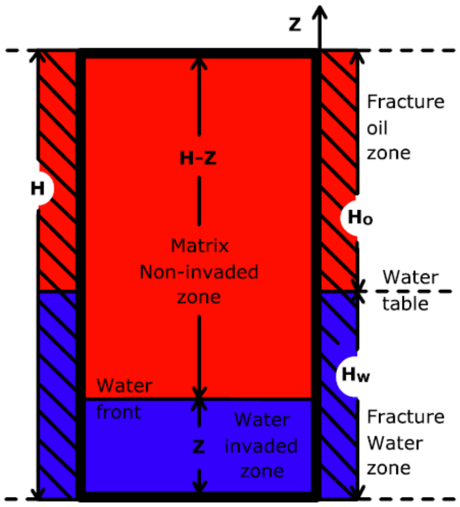
$$p_{total} = p_c + G = h_c(\rho_w - \rho_o)g + (H_w - z)(\rho_w - \rho_o)g$$

Displacement front velocity

Introducing Darcy's equation (each side of the front):

$$u = -\frac{k_w}{\mu_w}\frac{\Delta P_w}{z} = -\frac{k_o}{\mu_o}\frac{\Delta P_o}{(H-z)}$$

$$\Delta p_{total} = \Delta p_w + \Delta p_o$$



Displacement front velocity. Solution.

$$u = \frac{(H_w - z)(\rho_w - \rho_o)g + p_c}{\dfrac{\mu_w z}{k_w} + \dfrac{\mu_o (H - z)}{k_o}}$$

Special case: Total immersion

$H = H_w$

Introducing dimensionless front position $z_D = z/H$
and mobility ratio:

$$M = \frac{k_w \cdot \mu_o}{\mu_w \cdot k_o}$$

and

$$p_c = (\rho_w - \rho_o) g h_c$$

the front velocity equation becomes:

$$u = \frac{\left\{ (1 - z_D) + \frac{h_c}{H} \right\} (\rho_w - \rho_o) g \frac{k_w}{\mu_w}}{z_D + M(1 - z_D)}$$

Darcy velocity and intrinsic velocity.

When we want to evaluate time versus recovery for the matrix block we need the following concepts:

Darcy velocity: $$u = -\frac{k}{\mu}\frac{dp}{dz}$$

Intrinsic velocity (real velocity in the pore system):

$$\frac{dz}{dt} = \frac{u}{\phi_{eff}} = \frac{u}{\phi_m(1 - S_{wi} - S_{or})}$$

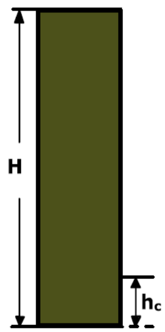
General formulation of recovery versus time for a totally immersed matrix block (1D flow)

$$dt = \frac{\phi_{eff} \cdot H\left\{z_D + M(1 - z_D)\right\}}{\left\{(1 - z_D) + \dfrac{h_c}{H}\right\}(\rho_w - \rho_o)g \cdot \dfrac{k_w}{\mu_w}} \cdot dz_D$$

This equation includes both capillary forces and gravity forces.

Gravity dominated flow:

If H>>h_c then h_c/H is approximately 0

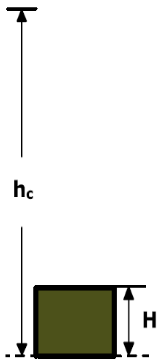


Capillary dominated flow

If the matrix block is small compared to the capillary height; h_c >> H

then

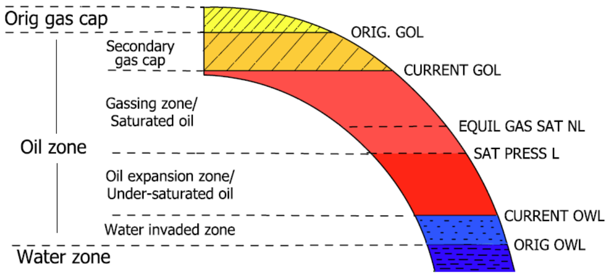
$$\frac{h_c}{H} >> 1 - z_D \quad \Rightarrow \quad \frac{h_c}{H} + (1 - z_D) = \frac{h_c}{H}$$



Gravity drainage matrix-fracture fluid exchange.

Most common process:

Gas cap expansion where gas invades the fractures while the matrix block are saturated with oil.



Other processes:

Oil migration from a source rock to a fractured reservoir initially saturated with water.

An oil wet fractured reservoir invaded with water (non-wetting phase).

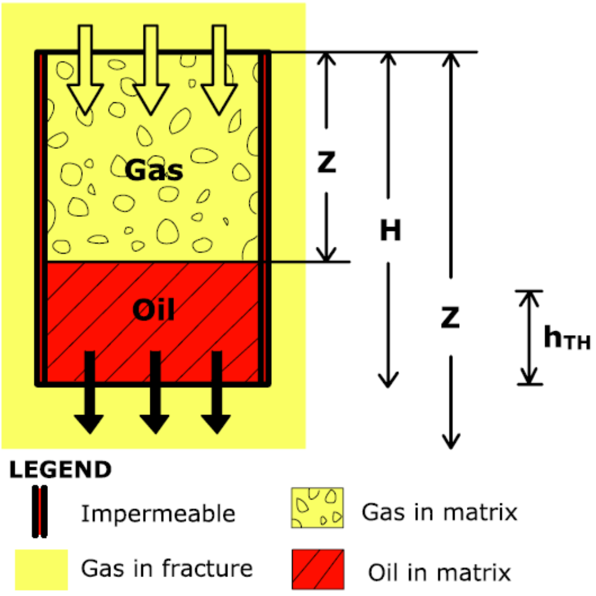
Model for the gas-oil drainage process in a matrix-fracture system

•The top of the matrix block is the reference level

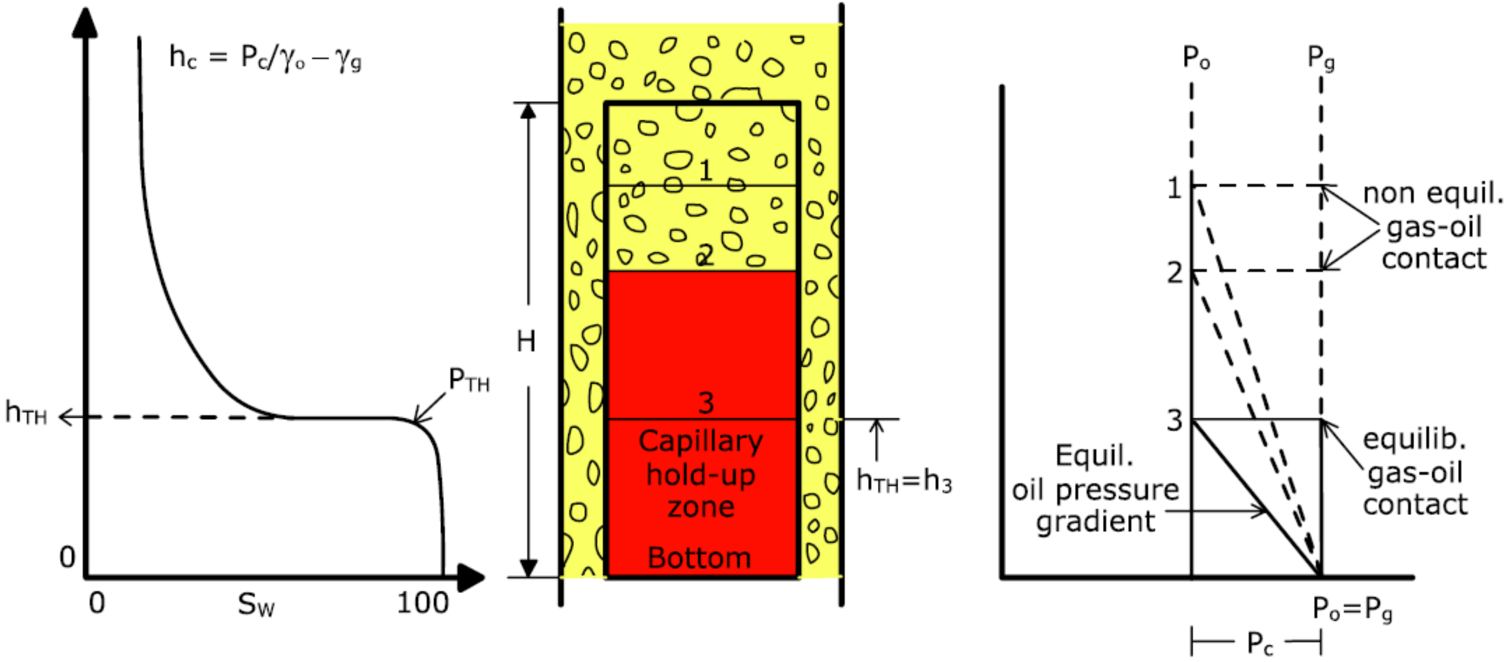
•The side faces of the block are impermeable

•The gas front position is at a distance Z from the reference plane (Z=0 corresponds to the top of the matrix block).

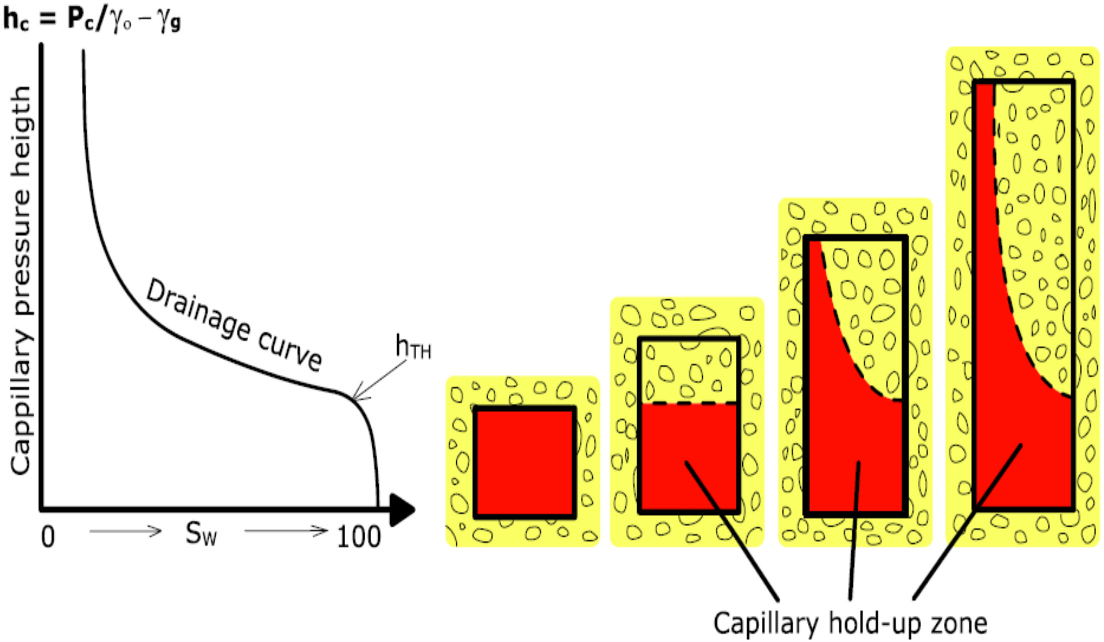
•The block height is H and the threshold height is h_{TH}
The maximum Z value is: $Z_{max} = H\text{-}h_{TH}$



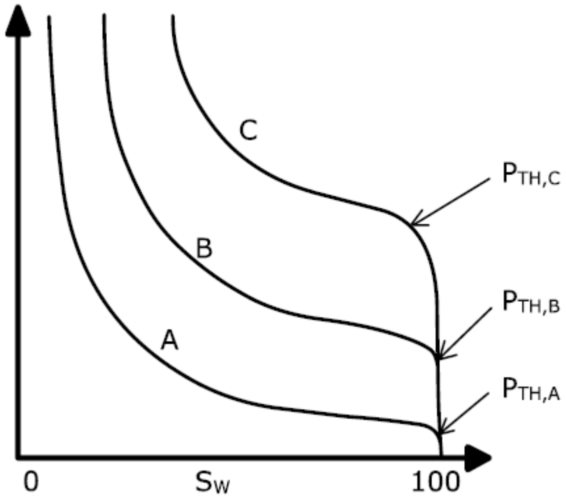
Relationship between oil and gas pressure in a gravity drainage process.



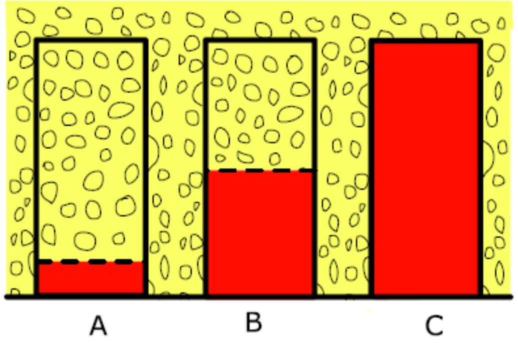
Capillary hold-up zone for various block heights.



Gravity drainage of blocks with different properties.

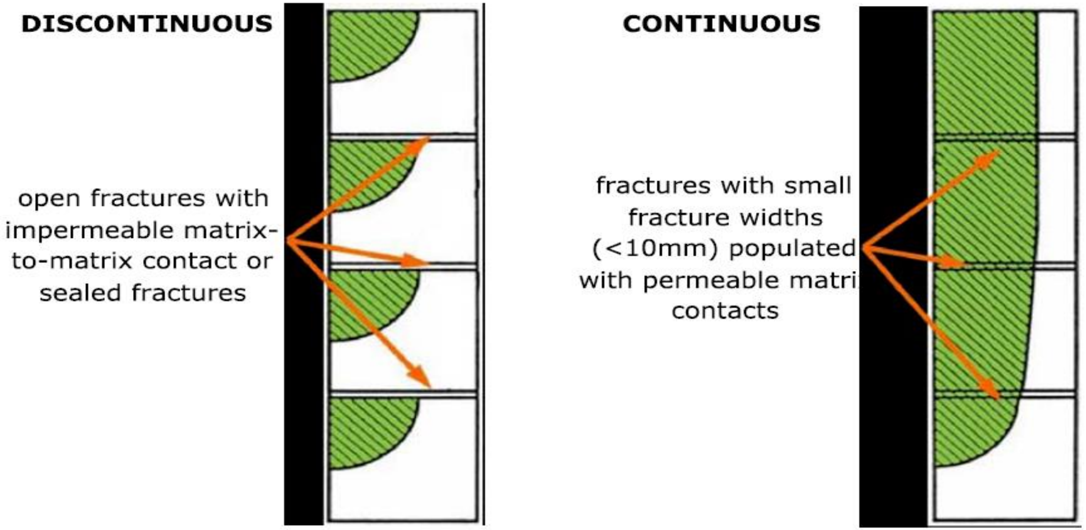


Drainage capillary curves of blocks A, B, C.

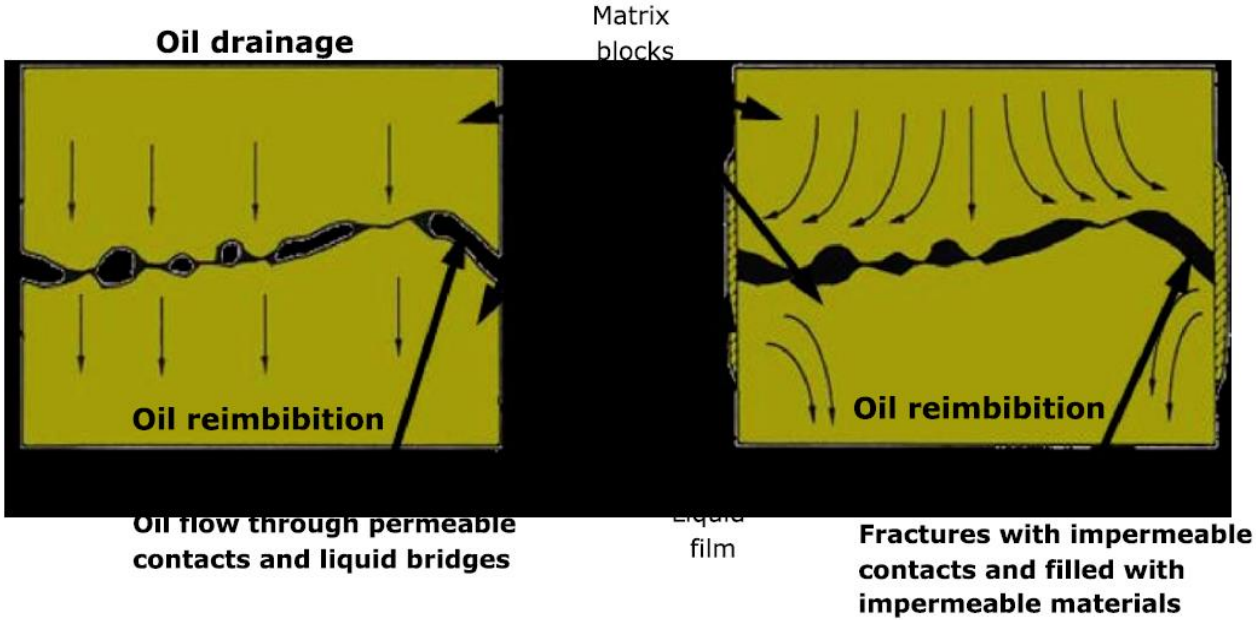


The permeability of the cores is ranged as follows: $k_A > k_B > k_C$

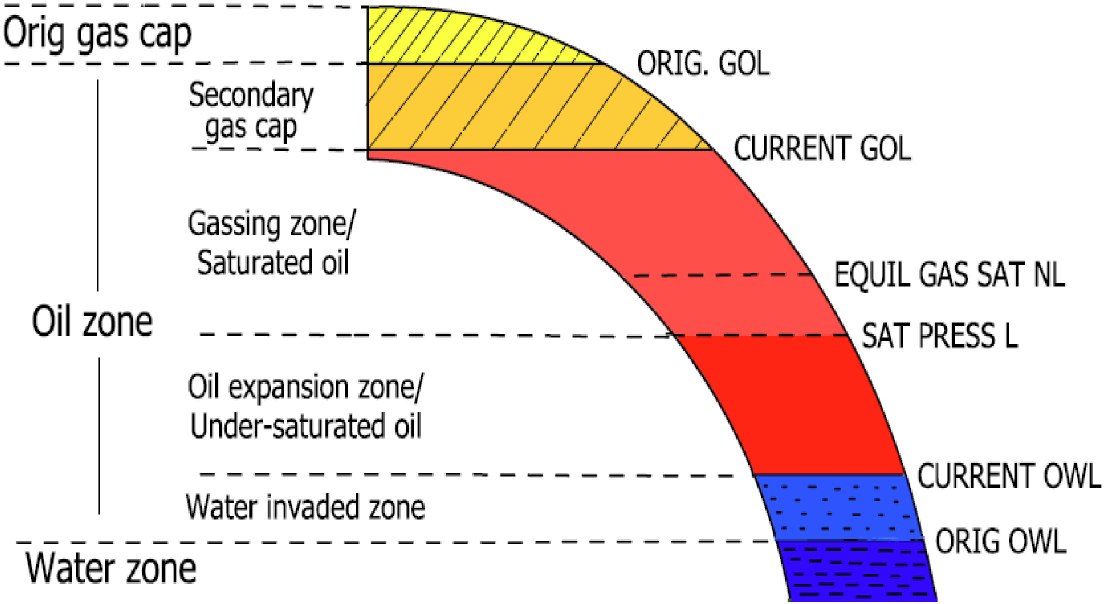
Concept of capillary continuity.



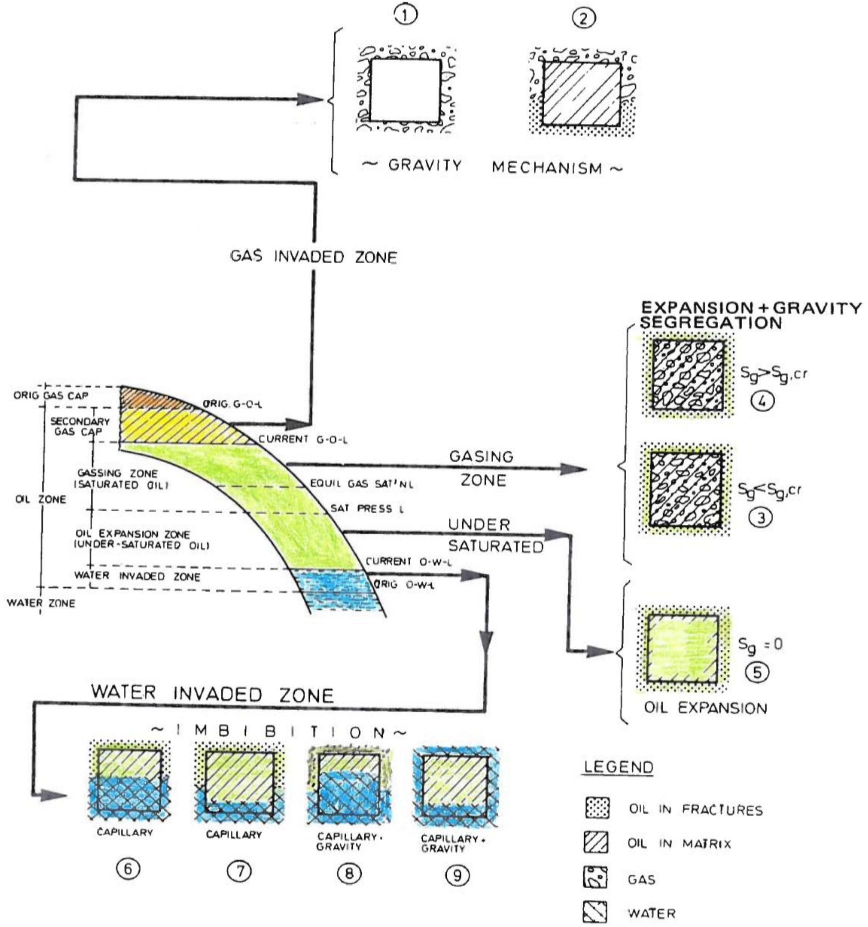
Re-infiltration of fluids from matrix blocks with high oil saturation to blocks with lower oil saturation.



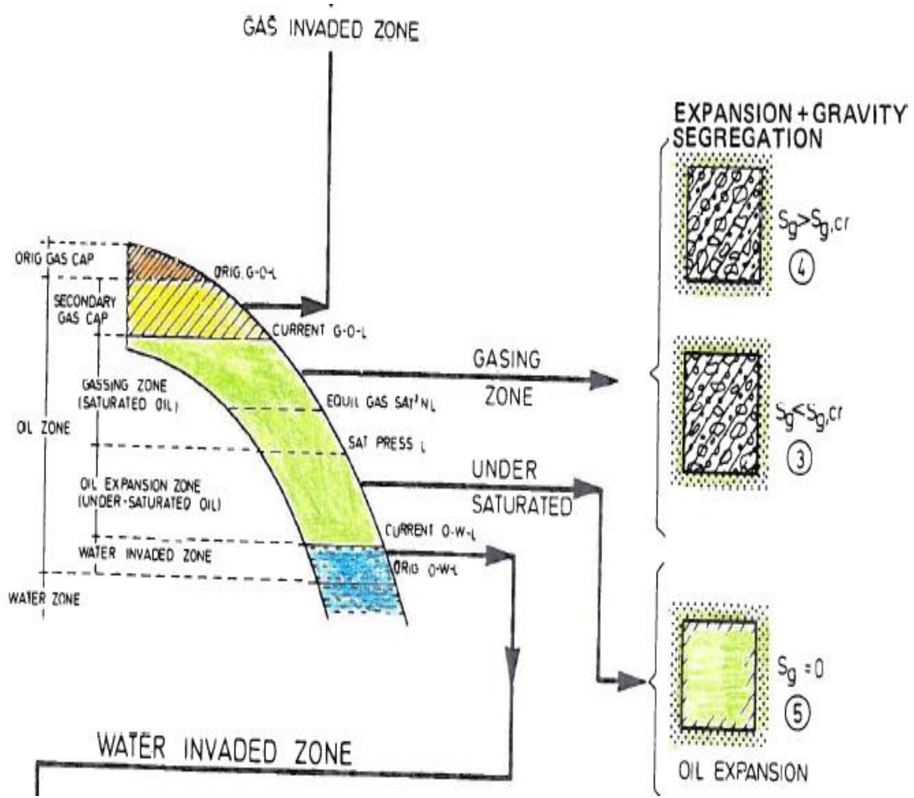
Total reservoir analysis.



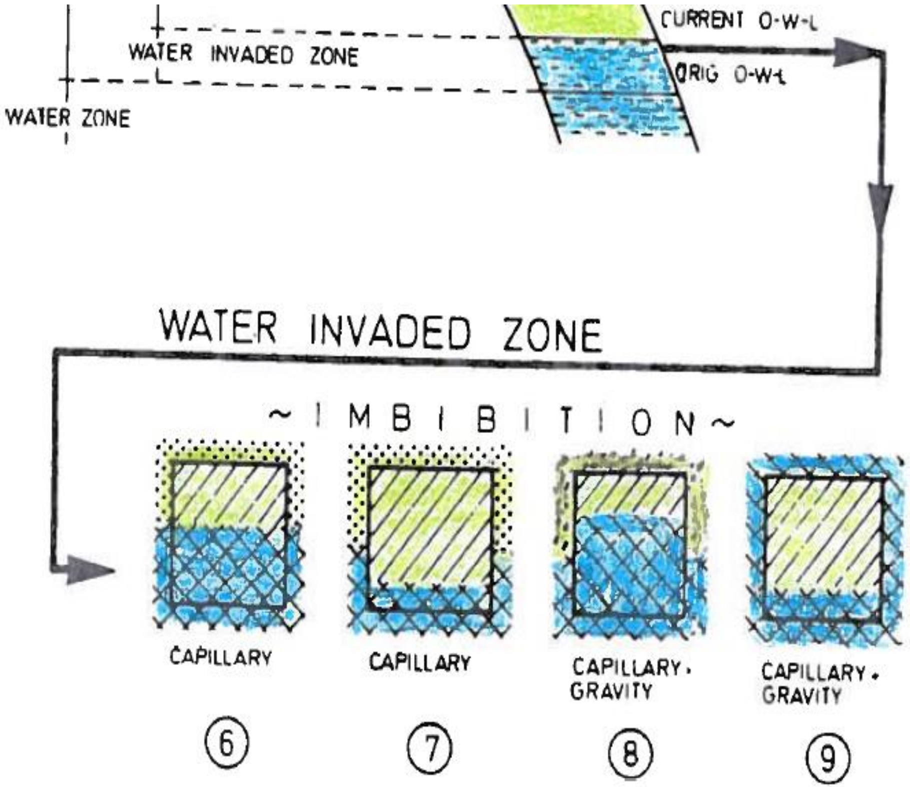
Production mechanisms in different zones of a fractured reservoir



Production mechanisms in different zones of a fractured reservoir



Production mechanisms in different zones of a fractured reservoir



Various production mechanisms and their respective zones.

Zone	Saturation			
	Matrix	Fractures network	Production mechanism	Block no. Observations
Gas invaded (1)	oil	gas	Gravity drainage	1 $(P < P_B)$
Gas invaded (1)	oil	gas + oil	Gravity drainage	2 $(P < P_B)$
Gassing zone (2)	oil gas	oil	Expansion of liberated gas	3 & 4 $(P<P_B)$
$S_g < S_{g,cr}$	oil + gas	oil	Convection	3 *(immobile gas)*
$S_g > S_{g,cr}$	oil + gas	oil		4 *(mobile gas)*

Various production mechanisms and their respective zones.

Zone	Saturation			
	Matrix	Fractures network	Production mechanism	Block no. Observations
Undersaturated oil (3)	oil	oil	Monophase expansion	5 *($P > P_B$)*
Water invaded (4)	water oil	water oil	Capillary imbibition	8 6 *(Fracture WOC below critical)*
			Gravity & imbibition	7, 9 *(Fracture WOC above critical)*

Total reservoir material balance.

Original oil in place (volumes at reservoir condition in each zone):

$$N \cdot B_o = V_{GIZ} + V_{SGD} + V_{EXP} + V_{WIZ}$$

Where

N is the volume of oil in the reservoir (Sm^3)

V_{GIZ} is the oil volume in the gas invasion zone

V_{SGD} is the oil volume in the solution gas drive zone

V_{EXP} is the oil volume in the oil expansion zone

V_{WIZ} is the oil volume in the water influx zone

Reservoir simulation formulations

Single porosity (1-Φ)

The standard reservoir simulation formulation is typically used for

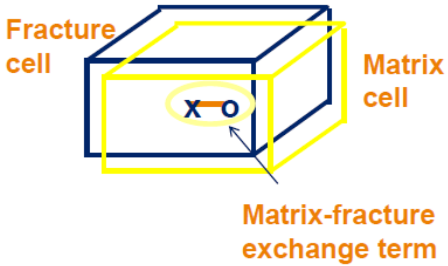
- Non-fractured reservoirs
- Fractured reservoirs where
  - Fracture permeability is included in total permeability
  - Pseudo relative permeabilities are used
- Small-scale studies of fractured reservoir

Reservoir simulation formulations (Cont'd)

Dual porosity (2-Φ)

- Two porosities, permeabilities, pressures, saturations etc. for each grid block that contains fracture + matrix

- No direct flow from matrix to matrix



Reservoir simulation formulations (Cont’d)

Dual porosity – dual permeability (2-Φ / 2-k)

– Similar to dual porosity, but includes flow directly from matrix to matrix

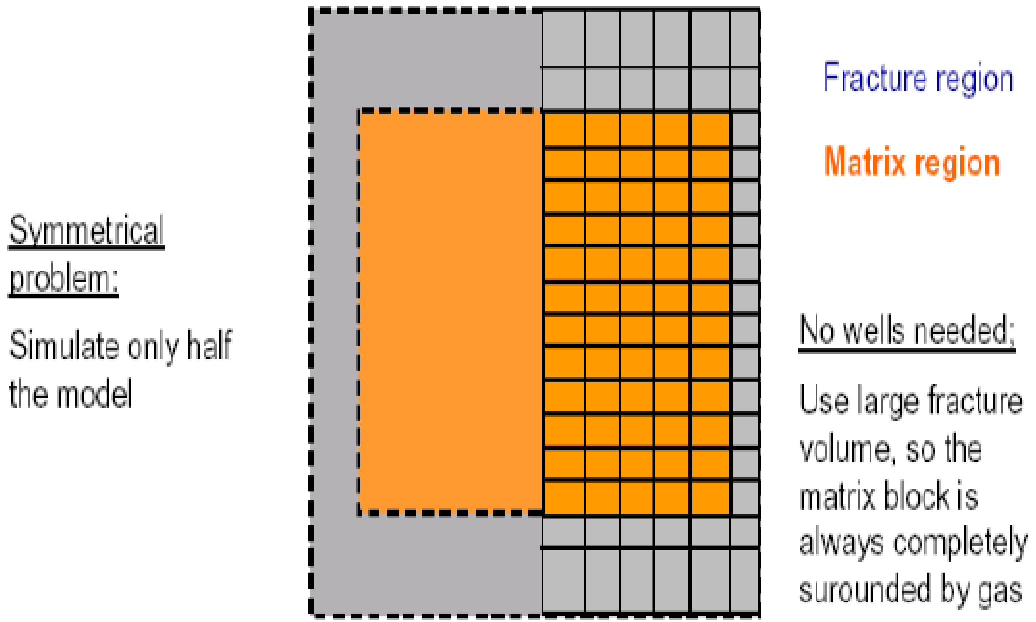
Hybrid models

– Combination of several formulations within a single reservoir simulation model

– Example: Fractured carbonate zones treated as dual porosity, while non-fractured sand is treated as single porosity

Small-scale modelling with fine grid: Gravity drainage of a single matrix block

- Fracture system initialized with gas. No capillary pressure
- Matrix system initialized with oil
- Only half of block included in fine-grid model

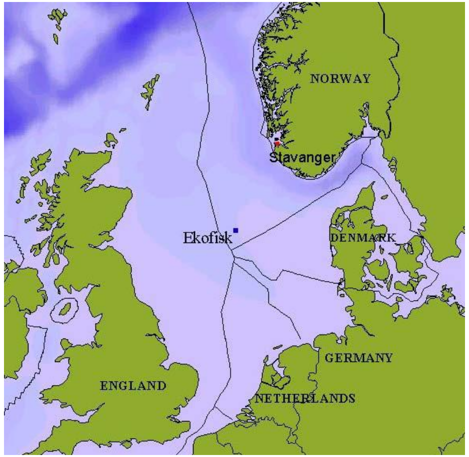


Effect of critical parameters for dual porosity reservoirs

Parameter	Primary Effect on Depletion	Primary Effect on Water Injection	Primary Effect on Gas Injection
Stack height	Ultimate recovery	Ultimate recovery (mixed wet systems)	Ultimate recovery
Matrix permeability	Production rate		
Capillary pressure	Ultimate recovery		
Rel-perm (shape)	Production rate		
S_{or} (residual oil saturation)	Ultimate recovery for low capillary/gravity ratios	Determines ultimate recovery for water-wet systems	Ultimate recovery for low capillary/ gravity ratios
S_{gc} (critical gas saturation)	Ultimate recovery for high capillary/gravity ratios.	Little effect	No effect
Compositional effects	Density and IFT versus pressure	Negligible	Effects on both rate and ultimate recovery
Diffusion	Negligible	Negligible	May be important for high capillary/gravity ratios

From Haugse (2014)

Ekofisk Oil Field



Located in the southern part of the North Sea, some 280 kilometers southwest of Stavanger.

Operated by ConocoPhillips Norge.

Production started on June 9, 1971.

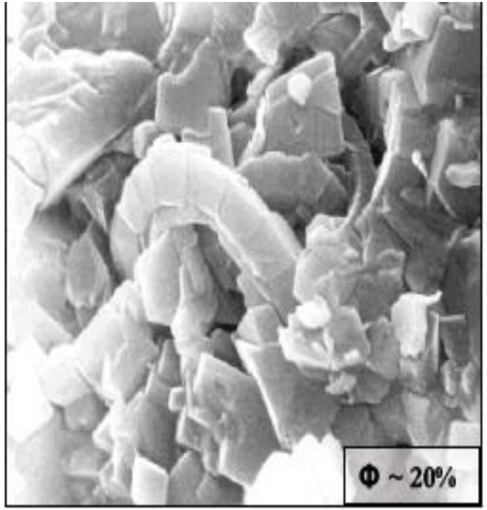
The area has been developed through several stages.

Reserves

- One of the 10 biggest offshore oil fields in the world.
- 7 billion barrels of oil originally in place.
- Most oil reserves left in the ground of Norwegian fields.
- A good example of exceptional reserve growth, due to improved understanding of fractured chalk production behaviour.
- The compaction has increased the reserve from 180 to 560 Mm^3.

Reservoir description

- The reservoir lies about 2,900-3,250 metres below sea level.
- The reservoir rocks are fine grained and dense chalk (made of micrometer algaes).
- The chalk matrix has a porosity in the order of 25-40% with permeability ranging from 0.1 to 10 mD.
- Fluid flow is largely governed by the distribution, orientation, and interconnectivity of the natural fracture system. The effective permeability is in the range of 20-100mD.



Reservoir Description

The reservoir consists of about 180 m of productive chalk that is divided into two formations:

1. the Ekofisk formation (Danian Age), approximately 120 m thick. 15 to 30 m of the Ekofisk formation is dense (unfractured) chalk.

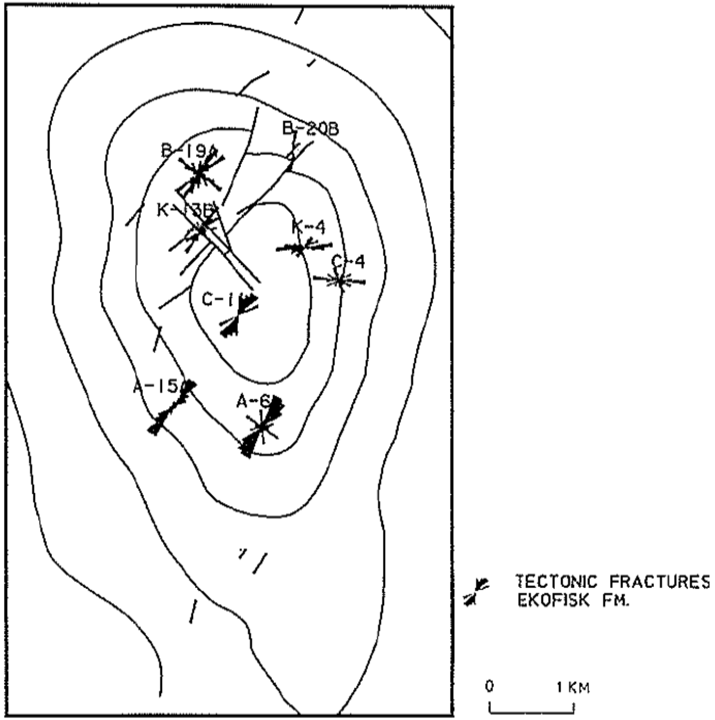
2. 60 m -thick section of highly fractured Tor formation chalk (Maastrichtian Age). The fracture intensity is increasing with depth.

Ekofisk reservoir parameters

- Average porosity, % 31.7
- Average matrix K, md. 1
- Max. Well test K, md. 200
- S_w %, 23.6
- Fractures types are found to be:
  1. Fractures associated with stylolites.
  2. Large scale faults.
  3. Tectonic fractures.

The main perm-enhancing fractures in Ekofisk.

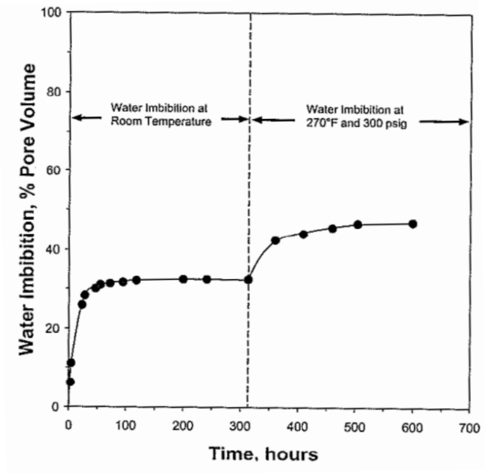
-Planar fractures, their dip range from vertical to 65 degrees.
-Tens of meters long.
-3 to 4 m. high.

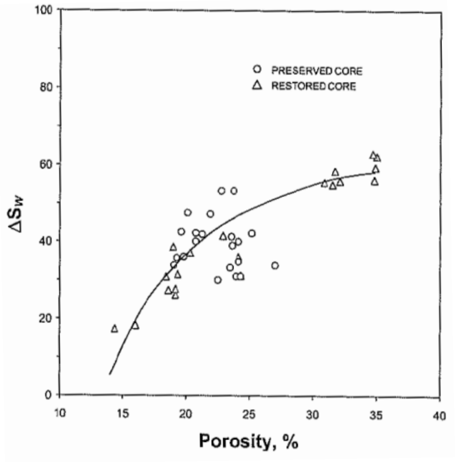


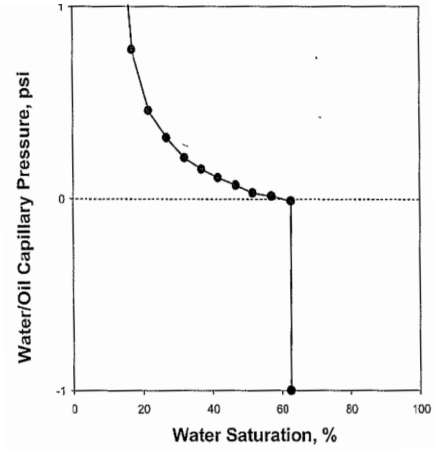
Water/Oil imbibition data

Water-oil imbition experiments were performed on cores from several wells. The experiments were as follows:

1. Measurements of imbibition data.
2. Oil recovery vs time.
3. Imbibition capilary pressure data.







Recovery strategy

- Experience has proven that water displacement of oil in fractured chalk is effective.
- The estimated reserves have been adjusted upwards several times.
- Limited gas injection and comprehensive water injection have contributed to a substantial increase in oil recovery.
- Pilot water injection projects were initiated in;
  - -1981 in the highly fractured Tor formation.
  - -1986 in the Lower Ekofisk.
- Large scale water injection started in 1987, and in subsequent years the water injection area has been extended in several phases.

Recovery

- Ekofisk was originally produced by pressure depletion and had an expected recovery factor of 17 per cent.

- Today the expected final recovery factor for Ekofisk is estimated to be over 50 per cent.

- In addition to the water injection, compaction of the chalk provides extra force to drainage of the field. The reservoir compaction has resulted in about 10 metres subsidence of the seabed, especially in the central part of the field.

- It is expected that the subsidence will continue, but at a much lower rate.

Status

- Production from Ekofisk is maintained at a high level through continuous water injection and drilling of new production and injection wells.

- The Ekofisk Life of Field Seismic (LoFS), installed in 2010, provides data for waterflood monitoring and reservoir management as well as observation of dynamic changes in the overburden.

- Drilling of wells, including remaining wells in the Ekofisk South development project, is ongoing.

- Installation of a new subsea injection template is ongoing, and injection is expected to start late in 2018.

Production history