PERTAMINA

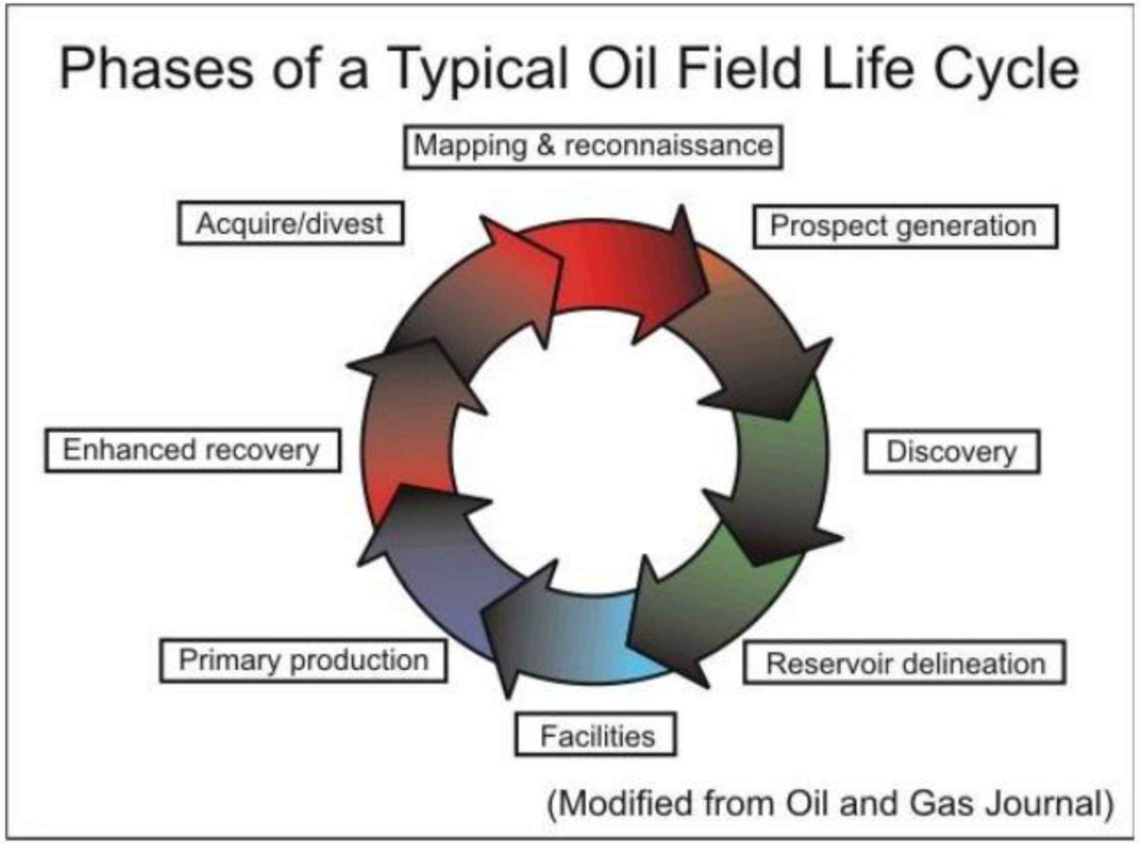
KULIAH TAMU

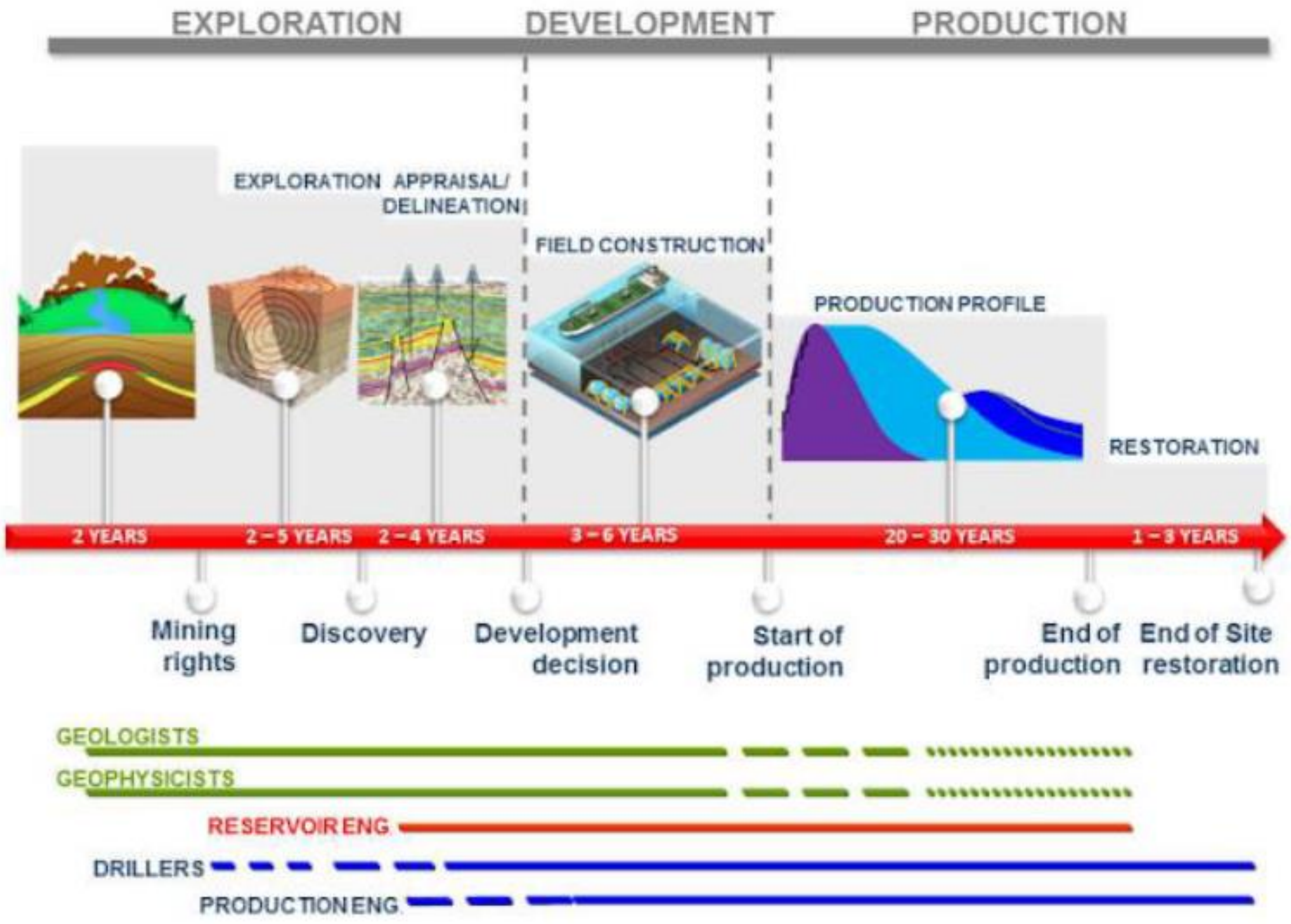
BASIC RESERVOIR ENGINEERING

MK. Geofisika Reservoir
Teknik Geofisika – ITS Surabaya

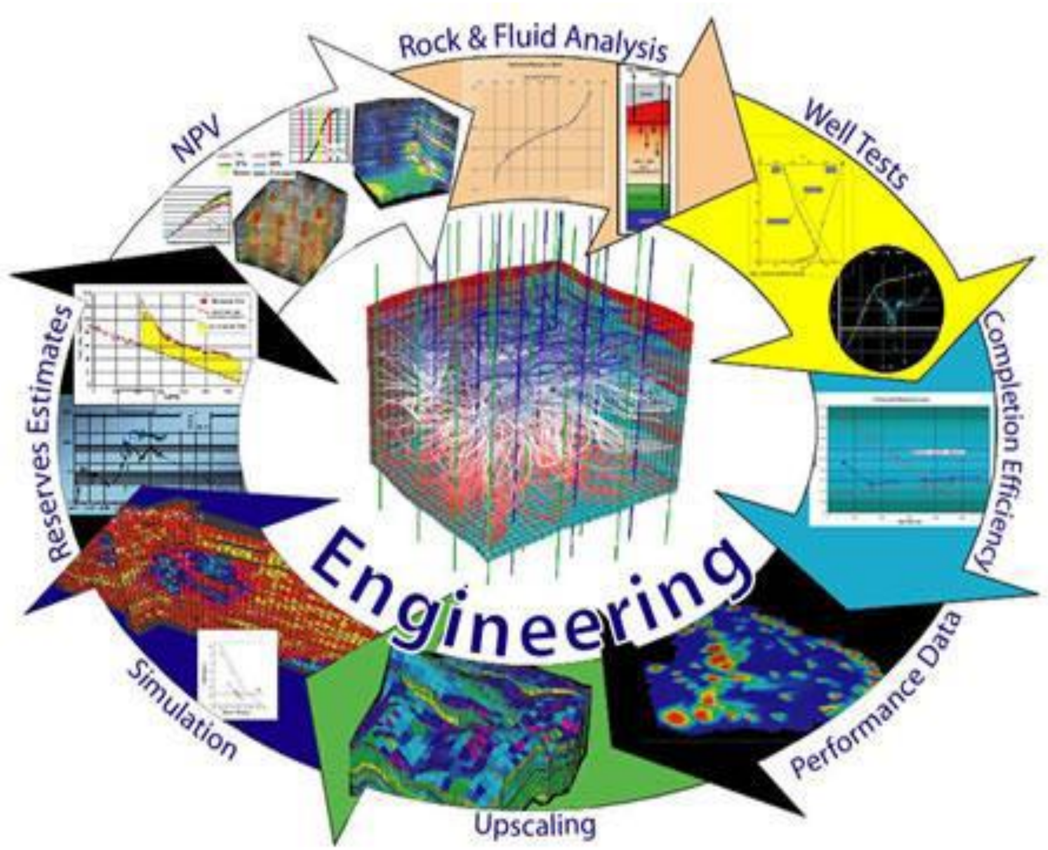
Surabaya, 23 Februari 2024

Oil/Gas Field Lifecycle

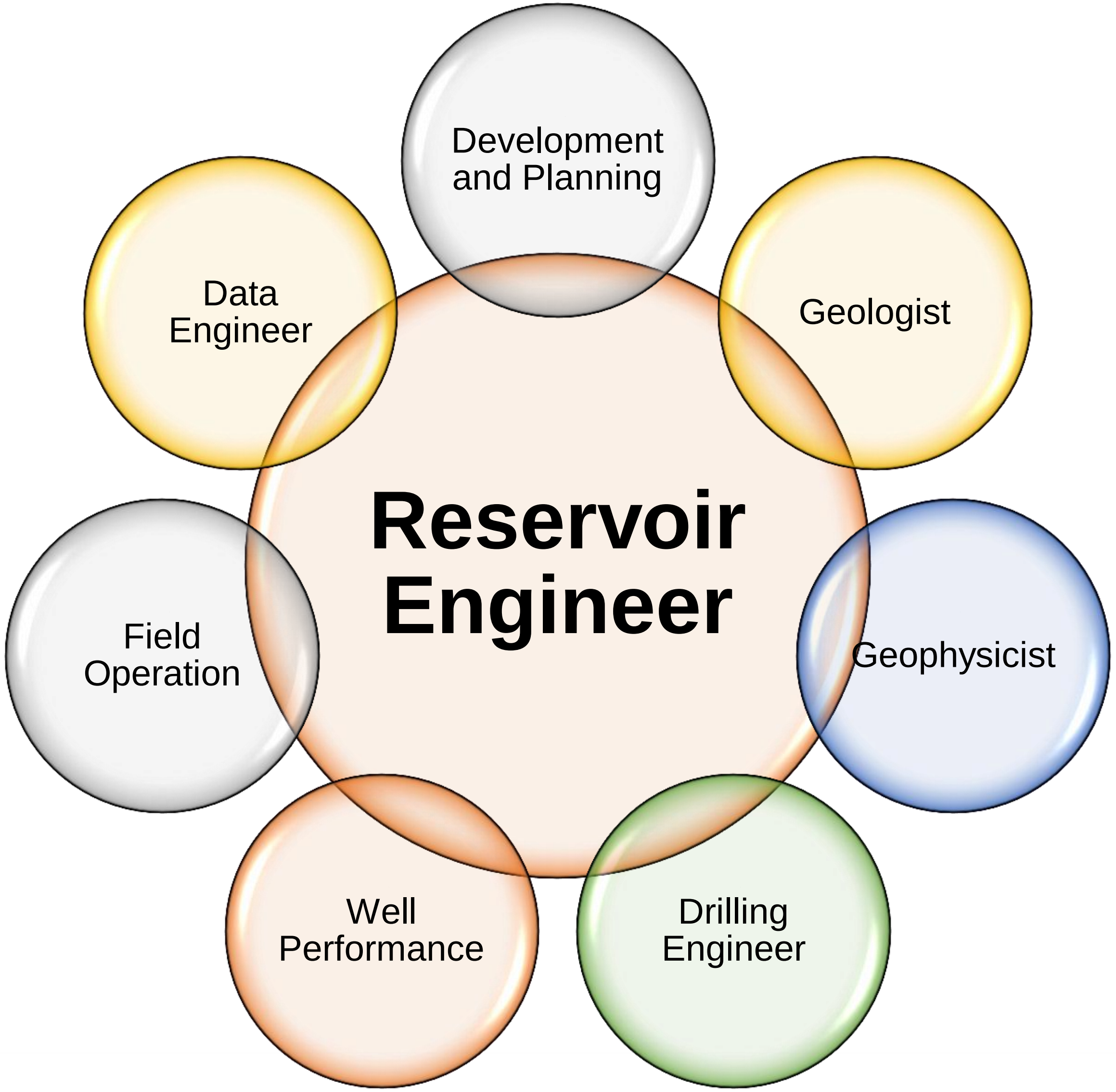





Chemistry
Engineering
Mathematics
Physics
Experience & Practice



Rock & Fluid Analysis
Well Tests
Completion Efficiency
Performance Data
Upscaling
Simulation
Reserves Estimates
NPV
Engineering


Development and Planning
Data Engineer
Geologist
Reservoir Engineer
Field Operation
Geophysicist
Well Performance
Drilling Engineer

Main Topics in Reservoir Engineering

01 **ROCK AND FLUID PROPERTIES**

02 **DECLINE CURVE**
Forecast future performance

03 **MATERIAL BALANCE**
Estimate volume: HC, aquifer

04 **PRESSURE TRANSIENT ANALYSIS**
Estimate reservoir/well geometry/property (boundary, P, perm, skin)

05 **RESERVOIR / DYNAMIC SIMULATION**
Evaluate subsurface uncertainties

06 **WATERFLOOD / EOR**
Improve recovery factor

07 **NODAL ANALYSIS**

08 **SUBSURFACE UNCERTAINTY**

09 **RESERVES ESTIMATES, BOOKING, AND REPORTING**

INTRODUCTION TO RESERVOIR ROCKS

- Porosity
- Permeability
- Saturation
- Wettability
- Cappilary Pressure
- Rock Compressibility

POROSITY

"The fractional void space within a rock that is available for the **storage of fluids**"

$$\phi = \frac{\text{pore volume}}{\text{bulk volume}}$$

where ϕ = porosity

Rock Type	Range
Unconsolidated sands	35 – 40%
Sandstones	20 – 35%
Tight/well cemented sandstone	15 – 20%
Limestone	5 – 20%
Dolomites	10 – 30%
Chalk	5 – 40%

**Source: ICL. typical porosity values in North Sea*

Pore Space Classification :

1. Absolute Porosity

$$\phi_a = \frac{\text{bulk volume} - \text{grain volume}}{\text{bulk volume}}$$

where ϕ_a = absolute porosity.

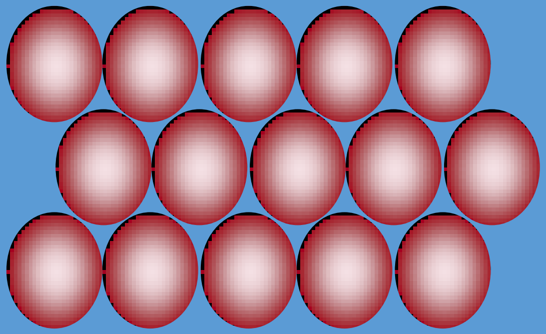
2. Effective Porosity

$$\phi = \frac{\text{interconnected pore volume}}{\text{bulk volume}}$$

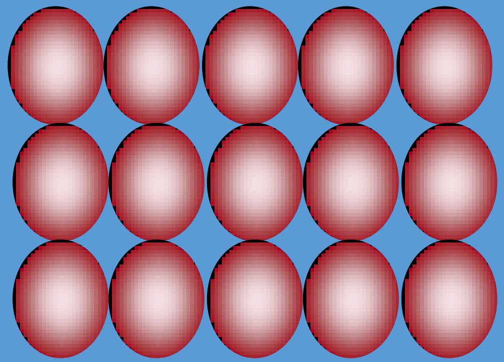
where ϕ = effective porosity.

- Very Clean Sandstones : $\Phi a = \Phi e$
- Highly cemented materials and most carbonates : $\Phi e < \Phi a$

Factors Affect Porosity

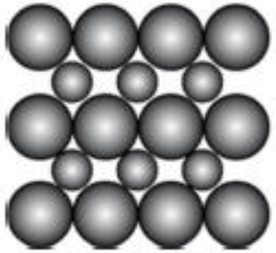


- **Rhombohedral packing**
- **Pore space = 26 % of total volume**



- **Cubic packing**
- **Pore space = 47.6 % of total volume**

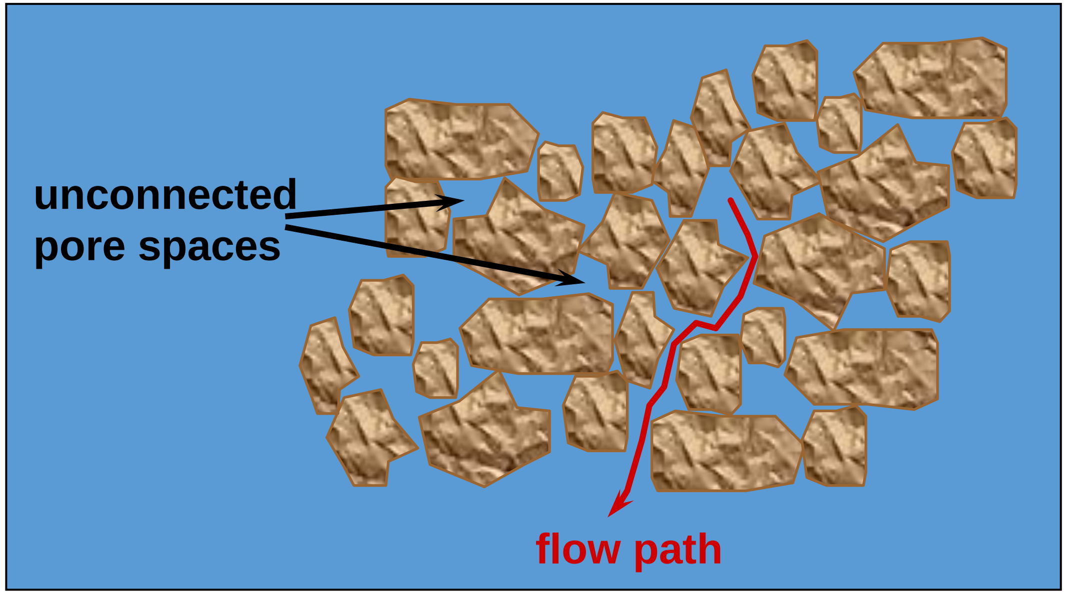
Φ < 5%	**Low:** tight carbonates
10% < Φ < 20%	**Average**
Φ > 20%	**High:** unconsolidated sand/chalk



Cubical packing (2 sizes) Φ = 12.5%

“Permeablity is a measure of the rock’s ability to **transmit fluid**”

- **Porosity** to retain fluid
- **Permeability** to allow the fluid to move



Permeability is a dynamic property that changes during sedimentation

$$k = \frac{q\,\mu\,L}{A\,\Delta p}$$

Darcy’s Law

K : Permeability,
Q : Flow rate
µ : Fluid Viscosity
L : Length of porous media
A : Area of Porous media
ΔP : Pressure drop in porous media

k = permeability (measured in darcies)

Dimension = $[L^2]$

1 Darcy = 0.987×10^{-12} m2 ≈ 10^{-12} m^2

- In general, a rock with permeability greater the 1 mD is considered a reservoir rock – 10 to 100 mD are high, and 100 to 1000 mD are very high permeability values

Methods of Permeability Measurement :

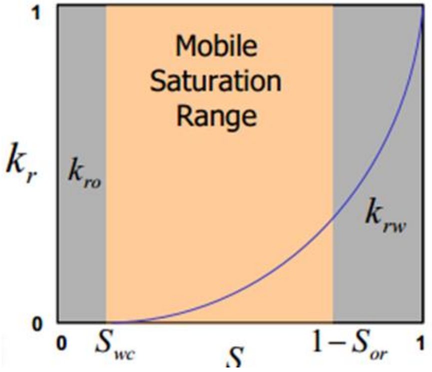
- Core : Run flow test and solve darcy's law for absolute permeability
- Well Flow Test : measure rate and driving pressure for calculating permeability

Type of Permeability

- Absolute Permeability, if there is **only one** fluid is present in porous media
- Effective Permeability, if there are **2 or more** fluids is present in porous media
- Relative Permeability, the ratio between effective permeability to absolute permeability

$$k_{eff} = k \times k_r$$

k_{eff} = effective permeability of the system to fluid "x"
k = absolute permeability of the rock
k_r = relative permeability of the system to fluid "x"



k_{abs} = is constant
k_r = is variable f(saturation)

$$k_{rw} = \frac{k_w}{k}$$

$$k_{ro} = \frac{k_o}{k}$$

$$k_{rg} = \frac{k_g}{k}$$

where k_{ro} = relative permeability to oil
k_{rg} = relative permeability to gas
k_{rw} = relative permeability to water
k = absolute permeability
k_o = effective permeability to oil for a given oil saturation
k_g = effective permeability to gas for a given gas saturation
k_w = effective permeability to water at some given water saturation

Example Relative Permeability Curve

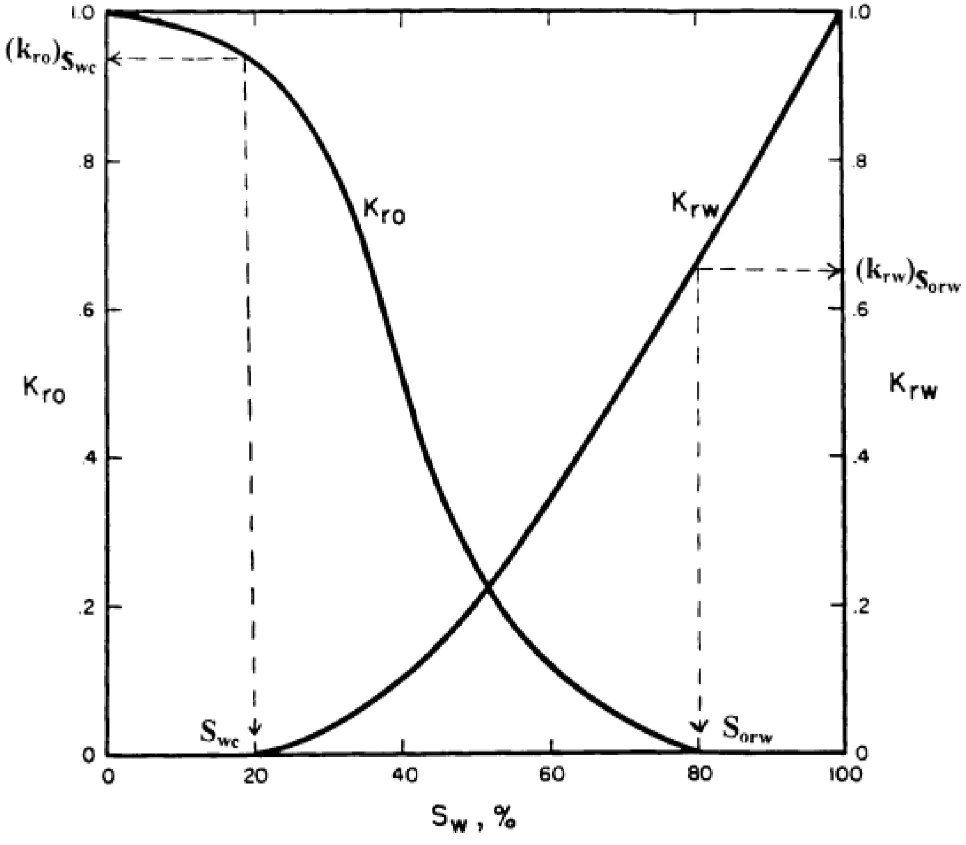


Figure 5-4. Water-oil relative permeability curves.

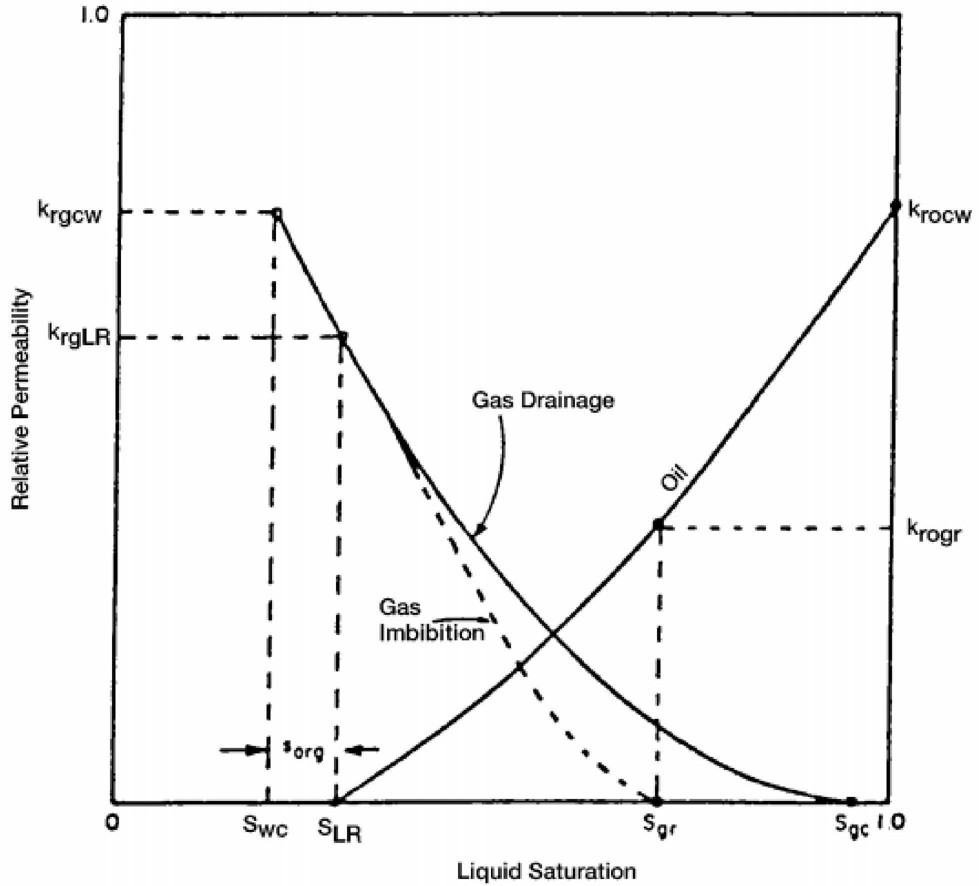
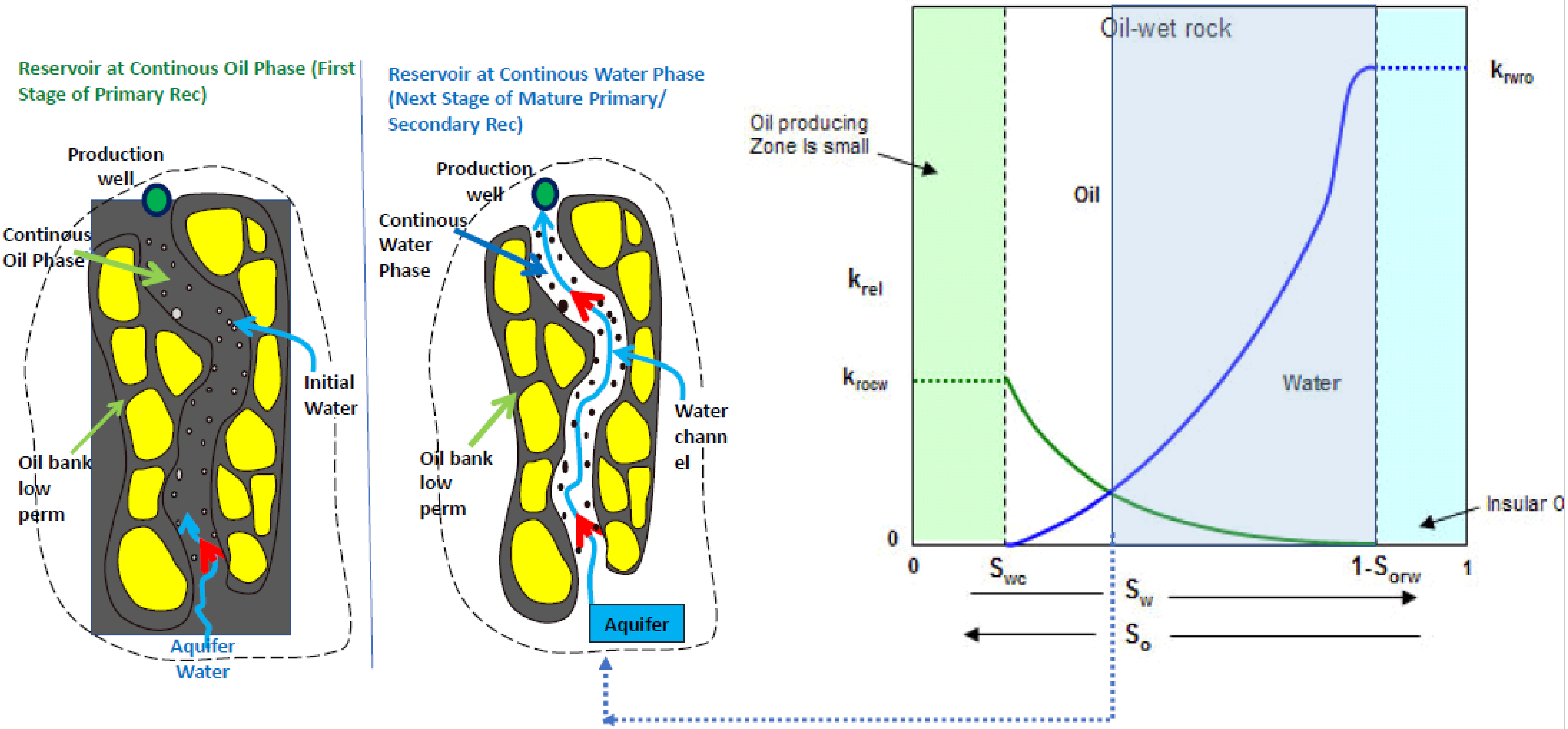


Figure 5-5. Gas-oil relative permeability curves.

Fluid Flow in Reservoir



Titik perpotongan Kro terhadap Krw adalah awal peningkatan Water cut secara signifikan karena mulai timbulnya jalur air di reservoir

[illegible]

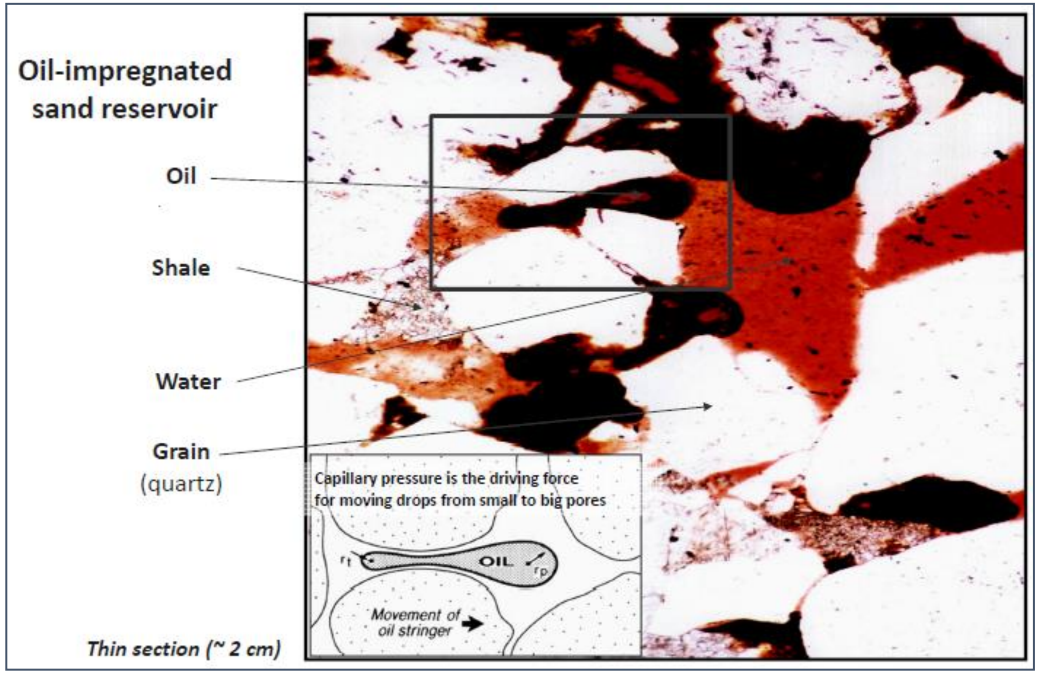
Fraction or percent of **pore volume occupied by a particular fluid** (oil, gas, or water).
Mathematically expressed by : (total volume of the fluid / pore volume)

$$S_o = \frac{\text{volume of oil}}{\text{pore volume}}$$

$$S_g = \frac{\text{volume of gas}}{\text{pore volume}}$$

$$S_w = \frac{\text{volume of water}}{\text{pore volume}}$$

where S_o = oil saturation
S_g = gas saturation
S_w = water saturation



$$S_w + S_o + S_g = 1$$

Water saturation→ fraction of porosity that contains water

Hydrocarbon saturation → fraction of porosity that contains hydrocarbon

Phase of saturation terminology :

1. **Swc (Connate Water Saturation)** : important primarily because it reduces the amount of space available between oil and gas. It is generally not uniformly distributed throughout the reservoir but varies with permeability, lithology, and height above the free water level
2. **Sor (Residual Oil Saturation)** : During the displacing process of the crude oil system from the porous media by water or gas injection (or encroachment) there will be some remaining oil left that is quantitatively characterized by a saturation value that is larger than the *critical oil saturation.* This saturation value is called the *residual oil saturation, Sor.* The term residual saturation is usually associated with the nonwetting phase when it is being displaced by a wetting phase.
3. **Soc (Critical Oil Saturation)** : For the oil phase to flow, the saturation of the oil must exceed a certain value which is termed critical oil saturation. At this particular saturation, the oil remains in the pores and, for all practical purposes, will not flow.
4. **Som (Moveable Oil Saturation)** :

$$S_{om} = 1 - S_{wc} - S_{oc}$$

where S_{wc} = connate water saturation

S_{oc} = critical oil saturation

INTRODUCTION TO RESERVOIR FLUIDS

Physical properties of reservoir fluids

- **Specific gravity**: (density of liq./dens. Water) or (density of Gas/dens. Air)
- **Gasoline or kerosene content**
- **Sulfur content**: (0.1, 1-7 weight % content)
- **Asphalt content**: black color and very viscous.
- **Pour point**: the lowest temperature where fluids still flow
- **Cloud point**: the temperature below which wax forms a cloudy appearance

Chemical properties of reservoir fluids

- Molecular structure
- Terminology of Paraffinic, Naphthenic, Naphthenic-aromatic and aromatic-asphaltic are often used to classify reservoir fluids

API Definition

SG = specific gravity of stock tank oil, relative to water at 60°F

$$^\circ API = \frac{141.5}{SG} - 131.5$$

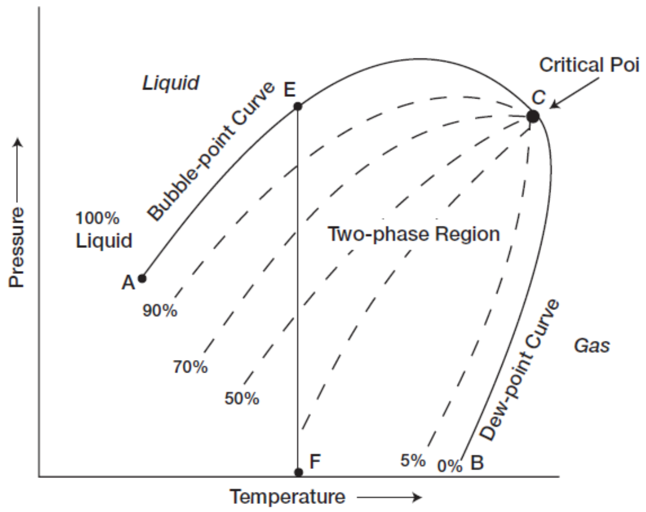
Fluid Type	SG	°API
Condensate or Very Light Oil	< 0.8	> 45
Light Oil	0.8 – 0.86	33 – 45
Medium Oil	0.86 – 0.92	22 – 33
Heavy Oil	0.92 – 1	< 22

Production Data

- API gravity
- Chemical composition
- Gas Oil Ratio (GOR)

Fluid Type	GOR
Oil	< 500
Oil or Condensate	500 – 1000
Gas Condensate	>1000
Wet Gas	>15000

The Conditions under which these phases exist are a matter of considerarable practical importance. It usually can be expressed by **phase diagrams**



Fungsi dari diagram tekanan vs temperature:

- Digunakan untuk menggambarkan sifat-sifat fluida ketika mengalir dari reservoir ke permukaan
- Untuk mengelompokkan fluida reservoir.
- Untuk strategi pengembangan yang bebeda dalam produksi minyak atau gas.

A. BLACK OIL

- Undersaturated oil
- Initial condition is far from critical point

B. VOLATILE OIL

- Undersaturated oil
- It has fewer heavy molecules than black oil, API gravity ~ 40˚ or higher
- Initial condition is close from critical point

C. RETROGRADE GAS CONDENSATE

- Initial condition = gas
- Reservoir temperature > critical temperature
- Reservoir temperature < maximum temperature

D. WET GAS

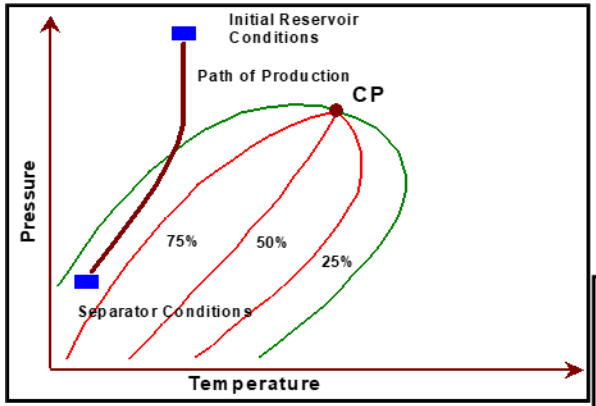
- Initial condition = gas
- Reservoir temperature > maximum temperature
- In reservoir condition, it still remains gas. However, at surface, some liquid are formed

E. DRY GAS

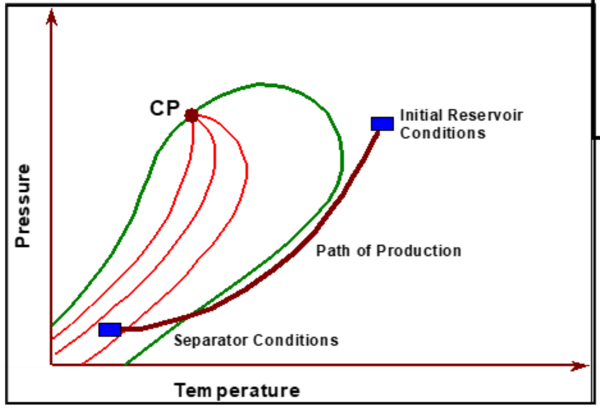
- Initial condition = gas
- Reservoir temperature > maximum temperature
- No liquid formed either in reservoir or at surface

The Five Reservoir Fluids

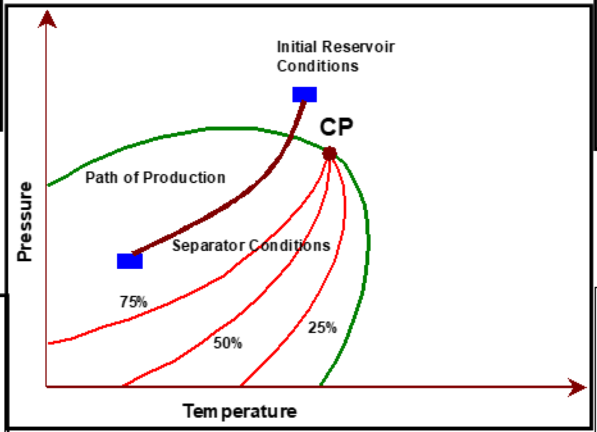
Black Oil Reservoir



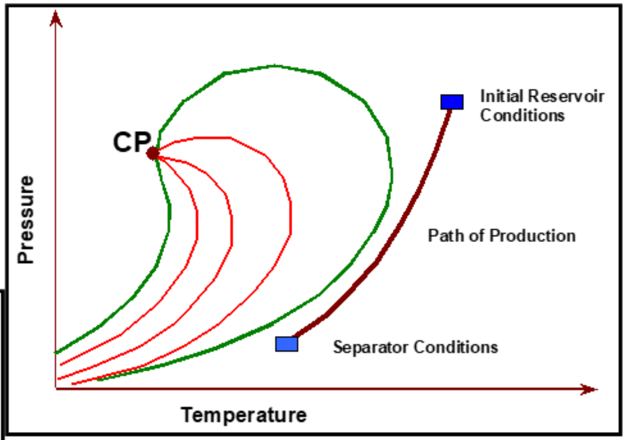
Wet Gas Reservoir



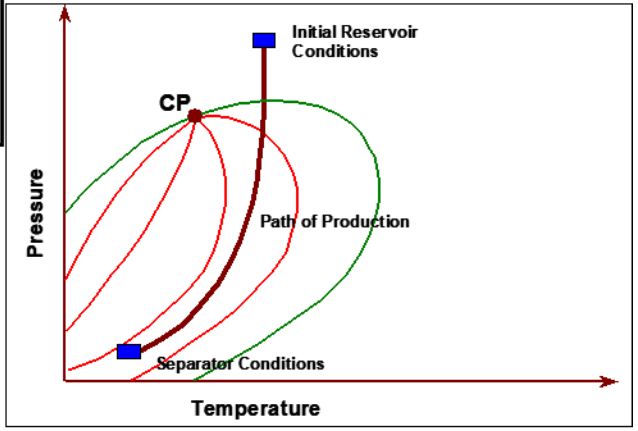
Volatile Oil Reservoir



Dry Gas Reservoir



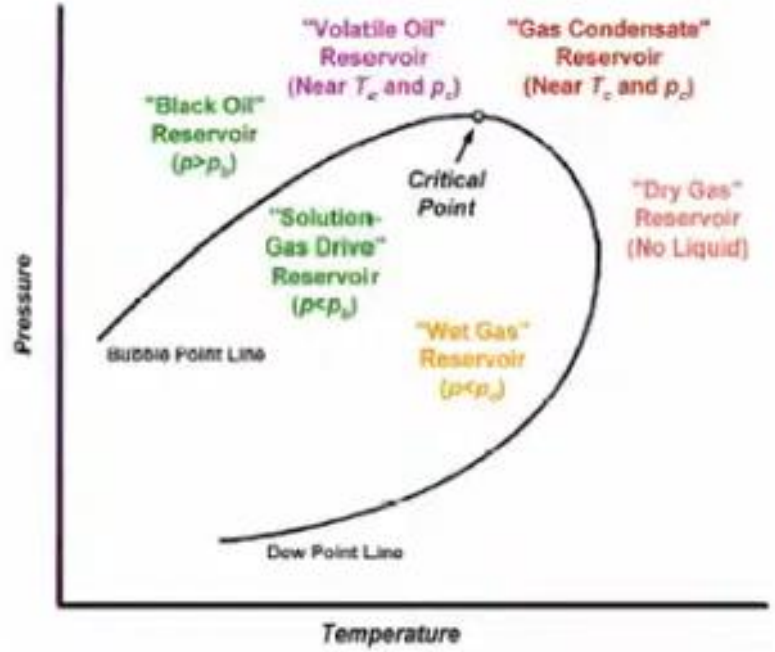
Retrograde Gas Reservoir



Reservoir Fluids

Generic Schematic Diagram for Hydrocarbon Reservoir Fluids

● From: *Fundamentals of Reservoir Engineering* — Calhoun (1953). (modified to reflect various reservoir fluid cases)



- <u>Schematic *p-T* Diagram</u>: Hydrocarbon Reservoir Fluids
  - Names represent conventional nomenclature.
  - Locations of names represent relative locations of these fluid types.

Orientation — Phase Behavior | Slide — 6

	Black Oil	Volatile Oil	Retrograde Condensate	Wet Gas	Dry Gas
GOR (m3/m3)	<300	300-600	>600	>2500	no liquid
API gravity	<40	>40	>40	up to 70	no liquid
liquid color	Black Green	Color, Red	light color	water white	no liquid
C7+ mol%	>20	12.5-20	4-12.5	0.7-4	<0.7

Note : 1 sm3/m3 :: 5.61 scf/bbl

HYDROCARBON IN PLACE CALCULATION

Initial In-Place = GRV * N/G * Phi * (1-S_w) / FVF

GAS → IGIP **OIL → OOIP**

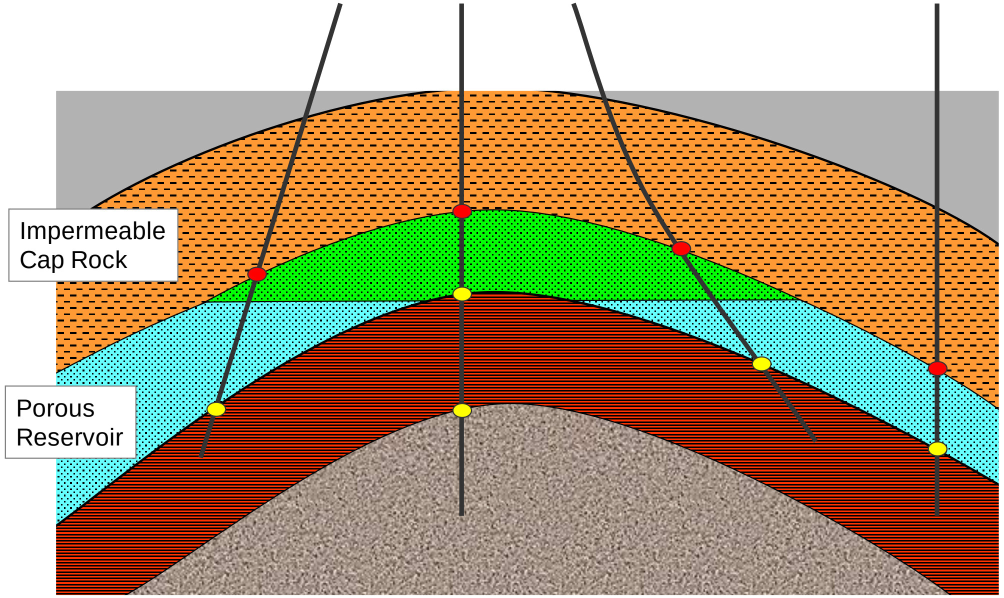
GRV
Total Volume of Rock (reservoir & non-reservoir) between two consecutive geological markers

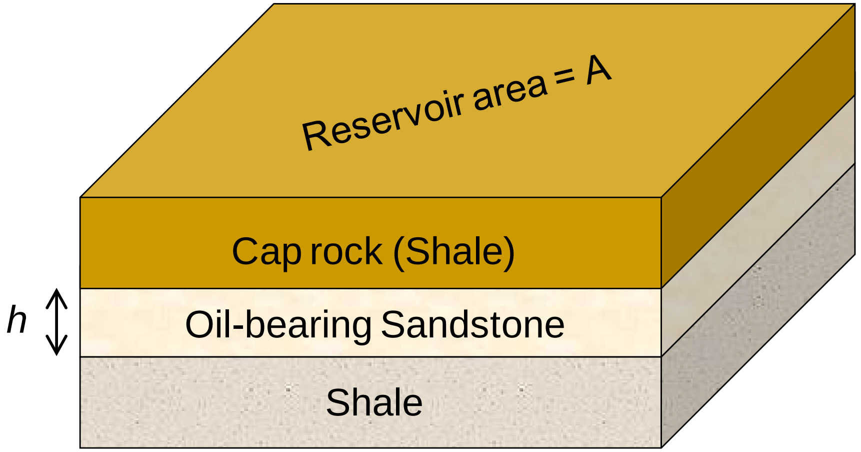
N/G
Net Reservoir Proportion (exclude non-reservoir) within GRV. Unit: fraction or %

Phi
porous space in reservoir rock which saturated by hydrocarbon (effective porosity). Unit: fraction or %

1-Sw
($S_{HC} = 1 - S_W$) Proportion of the porosity occupied by oil or/and gas. Unit: fraction or %

FVF
ratio of HC volume at standard/surface condition vs. reservoir condition. Known as Bo for OIL & Bg for GAS. Unit: v/v.



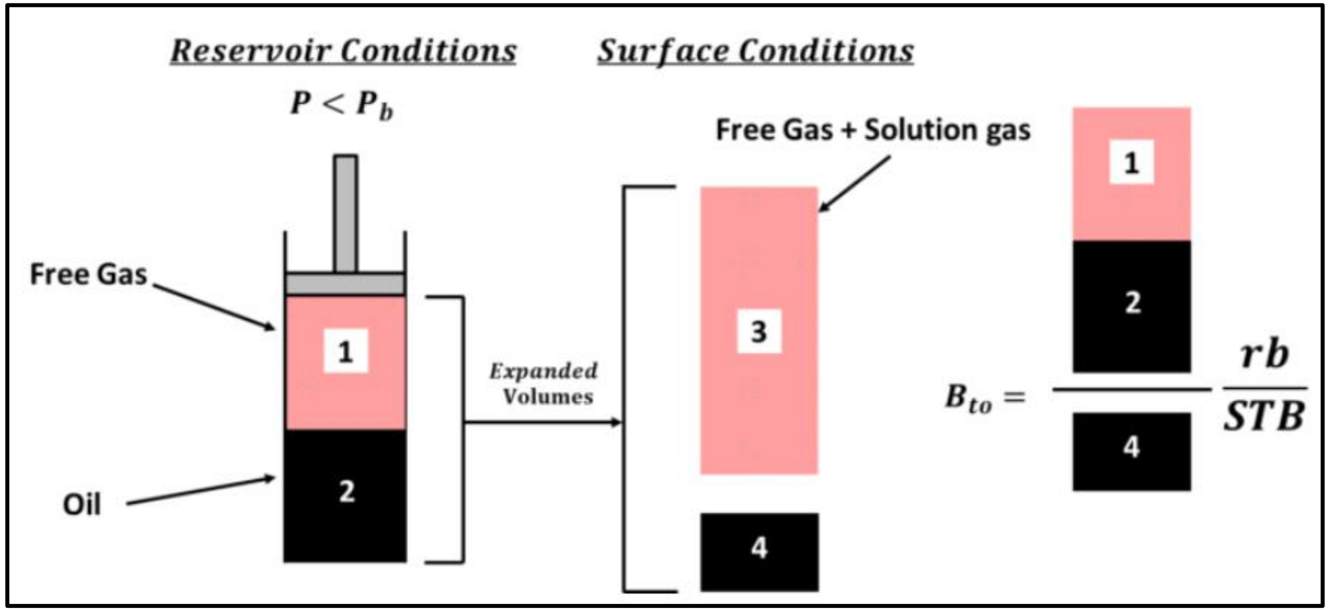


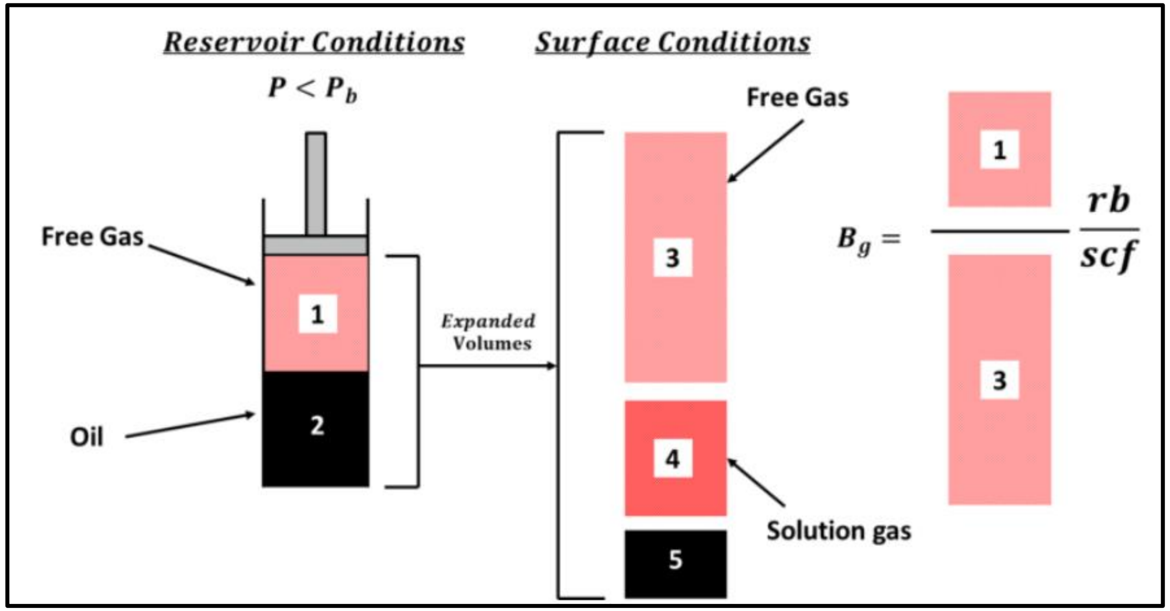
GRV	$h \times A$
Net Volume	$h \times A \times NTG$
Pore volume	$h \times A \times \text{NTG x } \phi$
HC volume	$h \times A \times \text{NTG x } \phi \times S_{hc}$
HC volume @ surface	$h \times A \times \text{NTG x } \phi \times S_{hc} \times 1/B_{o/g}$

$$Bo = \frac{Vo\ res}{Vo\ std} = \frac{\text{Volume of oil in reservoir (P \& T) conditions}}{\text{Volume of stock tank oil in standard conditions}}$$

$$Bg = \frac{Vg\ res}{Vg\ std} = \frac{\text{Volume of gas in reservoir (P \& T) conditions}}{\text{Volume of gas in standard conditions}}$$

Oil & Gas Formation Volume Factor





OIL RESERVOIRS the original oil-inplace(OOIP)

OOIP = 7,758 * Rock Volume * f* (1-Sw) * 1/Bo

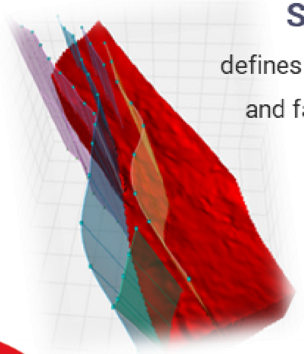
- Rock Volume (acre feet) = A * h
- A = Drainage area, acres
- h = Net pay thickness, feet
- 7,758 = API Bblper acre-feet (converts acre-feet to stock tank barrels)
- f= Porosity, fraction of rock volume available to store fluids
- Sw= Volume fraction of porosity filled with interstitial water
- Bo = Formation volume factor (Reservoir Bbl/STB) (dimensionless factor for the change in oil volume between reservoir conditions and standard conditions at surface)

GAS RESERVOIRS the original oil-inplace(OOIP)

OGIP = 43,560 * Rock Volume * f* (1-Sw) * 1/Bg

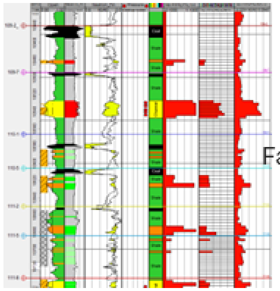
- Rock Volume (acre feet) = A * h
- A = Drainage area, acres (1 ha = 43,560 sq ft)
- h = Net pay thickness, feet
- 7,758 = API Bblper acre-feet (converts acre-feet to stock tank barrels)
- f= Porosity, fraction of rock volume available to store fluids
- Sw= Volume fraction of porosity filled with interstitial water
- Bg= Formation volume factor (Reservoir ft^3/SCF) (dimensionless factor for the change in gas volume between reservoir conditions and standard conditions at surface)

Understanding of regional geological context is paramount to build a proper geomodel



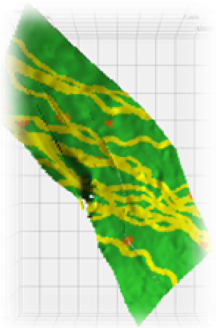
01 STRUCTURAL MODEL

defines geological surface/horizon and fault interpretation based on seismic



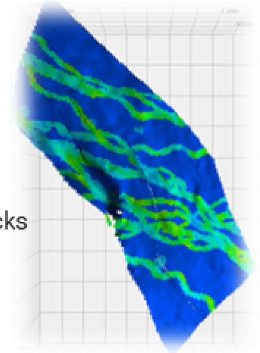
02 UPSCALE

Increasing the size of reservoir properties (NTG, Facies, Porosity, Permeability) from log scale into grid/cell scale.



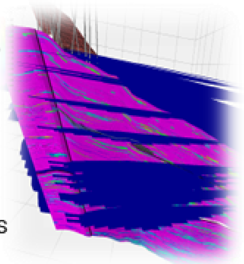
03 FACIES MODEL

defines the rock types or type of facies, trend of deposition, fairways, and the dimension of geobodies.



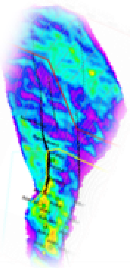
04 PETROPHYSICAL MODEL

Distributes the reservoir properties (NTG, Porosity, Permeability) inside reservoir rocks or facies using geostatistic approaches (sometimes guided by seismic attributes)



05 FLUID CONTACTS

Defines initial fluid contact (GOC or OWC), usually based on well to well correlation. In this part, Reservoir Engineering introduces the concept of transition zone above Free Water Level (known as J-Function)



06 VOLUMETRIC (IN-PLACE)

the result is a volume of hydrocarbon in the reservoir. The unit of volume shall be transferred in surface volume (requires Bo/Bg). In some cases, multi realization is required to introduce probabilistic values (P90, P50, P10)

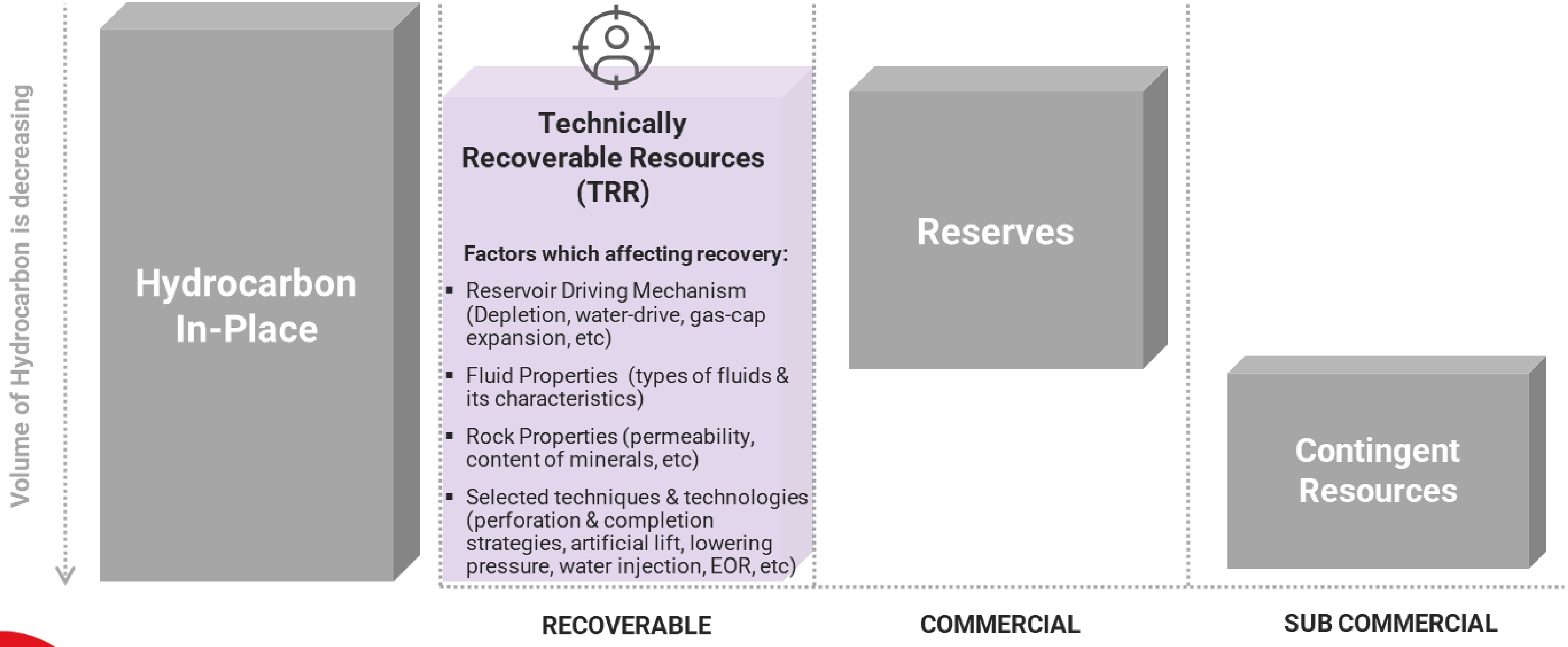
⚠ INITIALIZATION

STATIC GEOMODEL

General workflow is defined by Geologist to estimate the initial hydrocarbon volume in the reservoir. This process might be more complex or simpler depend on geological context and data availability

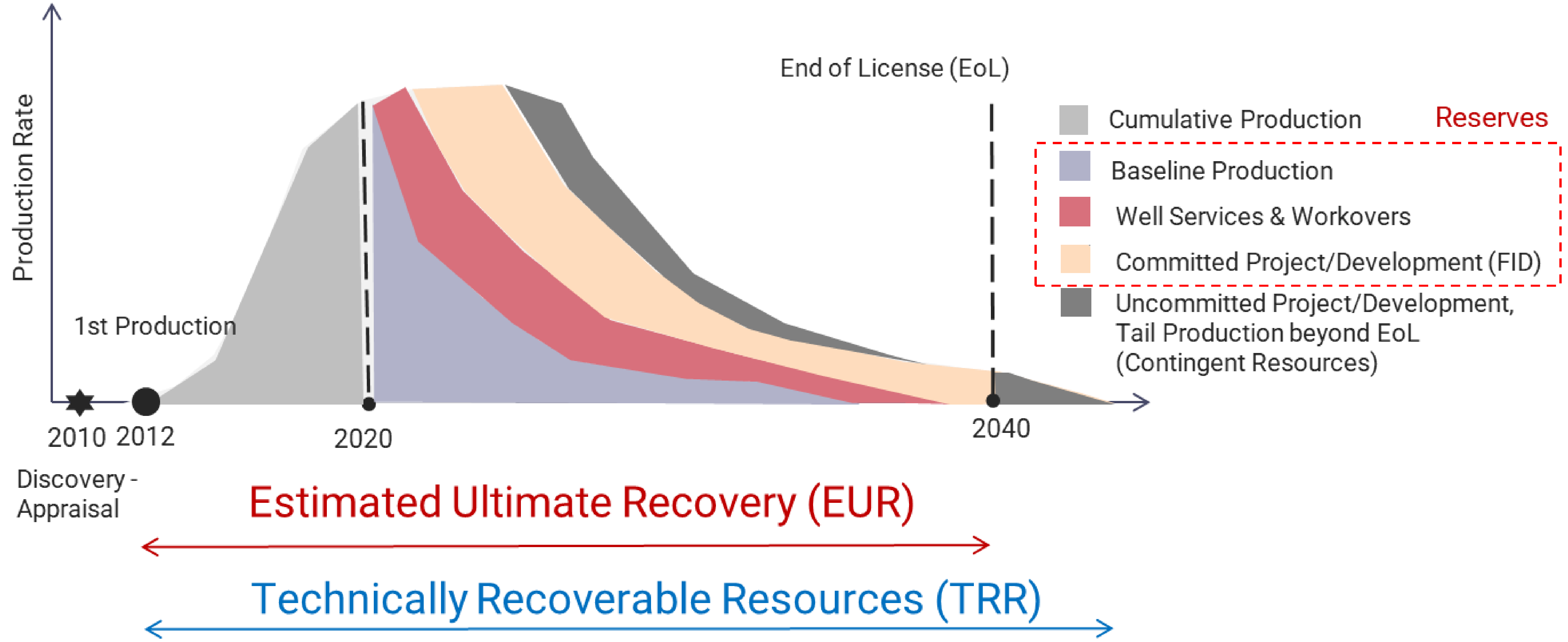
Technically Recoverable Resources

Those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations



Reserves, EUR, TRR: What is the different?

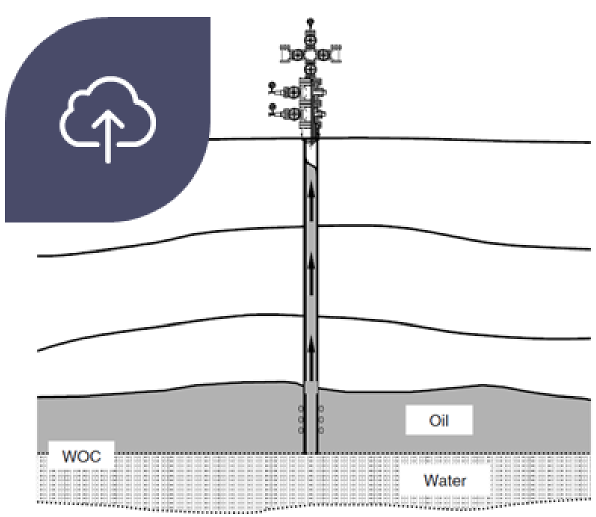
As Reserves is part of EUR, the border of both two terminologies lays on specific terms & conditions



PRMS (Rev. Jun-2018): 1.1.0.8

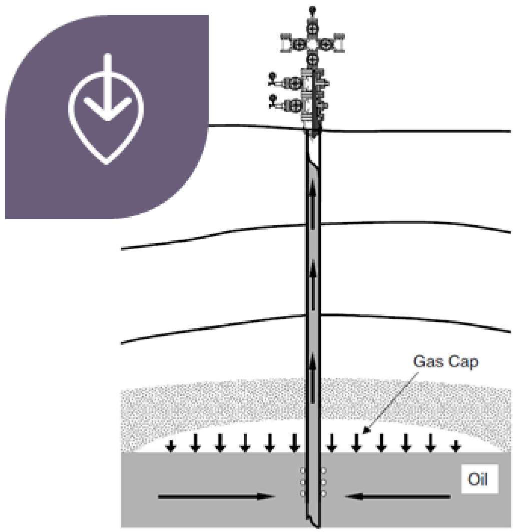
Reservoir Driving Mechanism

Driving mechanism is a natural pressure maintenance mechanism, while reservoir pressure is a key role for hydrocarbon recovery



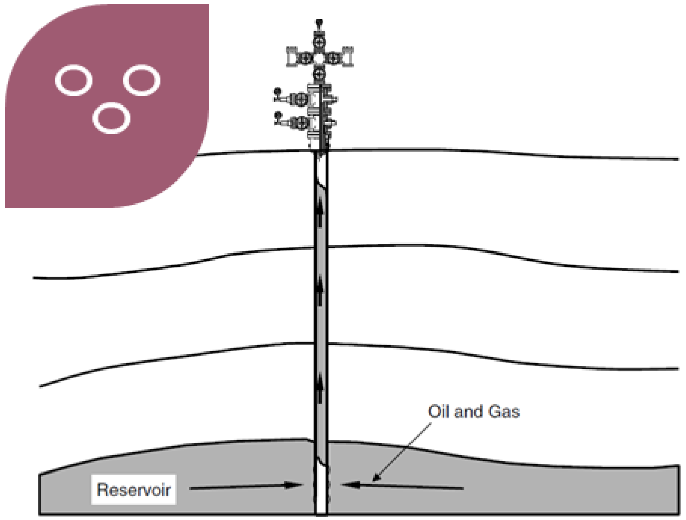
AQUIFER SUPPORT

- Reservoir Pressure is maintained, pressure depletion may occurred during high HC withdrawal rate
- High production water rate observed at well level
- Stable Gas-Oil Ratio (GOR) at well level
- Good recovery for Oil Reservoir (up to 60% of STOIIP)
- Poor recovery for Gas Reservoir, the gas reservoir can suddenly died once water breakthrough. Hence very dependent on how far the Gas-Water Contact (GWC)



GAS-CAP EXPANSION

- Reservoir pressure will be depleted during production, depletion can be more severed if gas cap is produced
- GOR will increase exponentially during production if gas-conning occurred
- Moderate oil recovery (up to 40% of STOIIP) depend how good the reservoir management strategies in order to avoid gas cap production



DEPLETION DRIVE

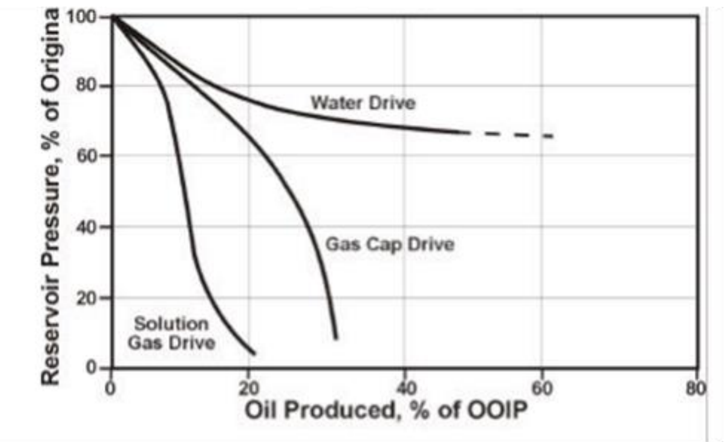
- Reservoir pressure will be sharply depleted during production
- GOR will increase rapidly once reservoir pressure dropped below bubble point pressure, then will sharply declined once the reservoir pressure becomes very depleted
- Low recovery for Oil Reservoir (max. 30% of STOIIP)
- Good recovery for Gas Reservoir (up to 90% of IGIP), will be driven by the network pressure in the surface.

Recovery IS NOT ONLY depend on the driving mechanism, hence what's called as "Recovery Factor" is a RANGE OF VALUE.

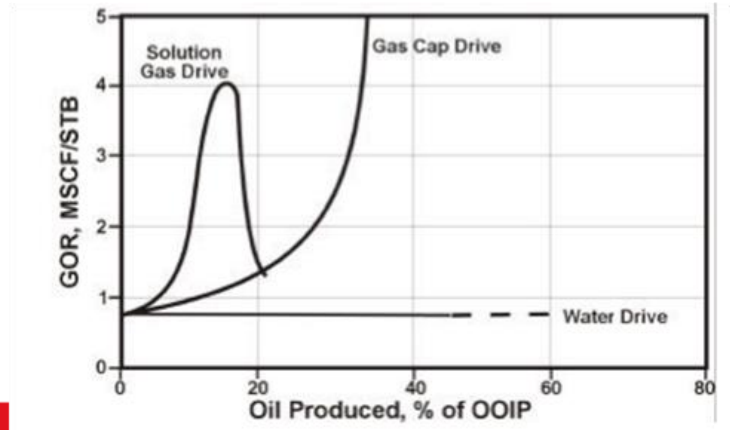
Driving Mechanism Identification

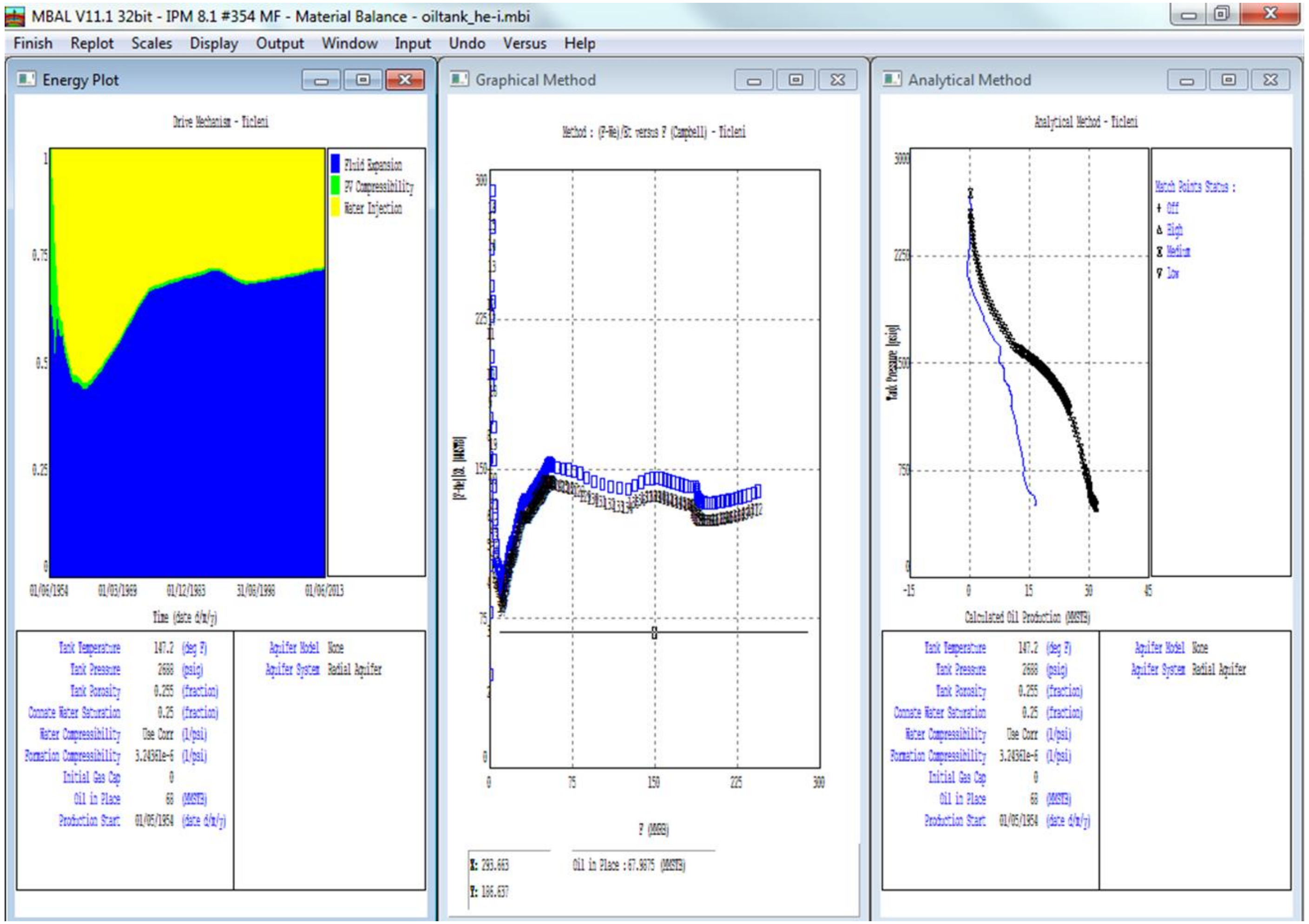
Good understanding on our reservoir driving mechanism leads to chose the best production strategy

Reservoir Pressure Trends for Drive Mechanisms

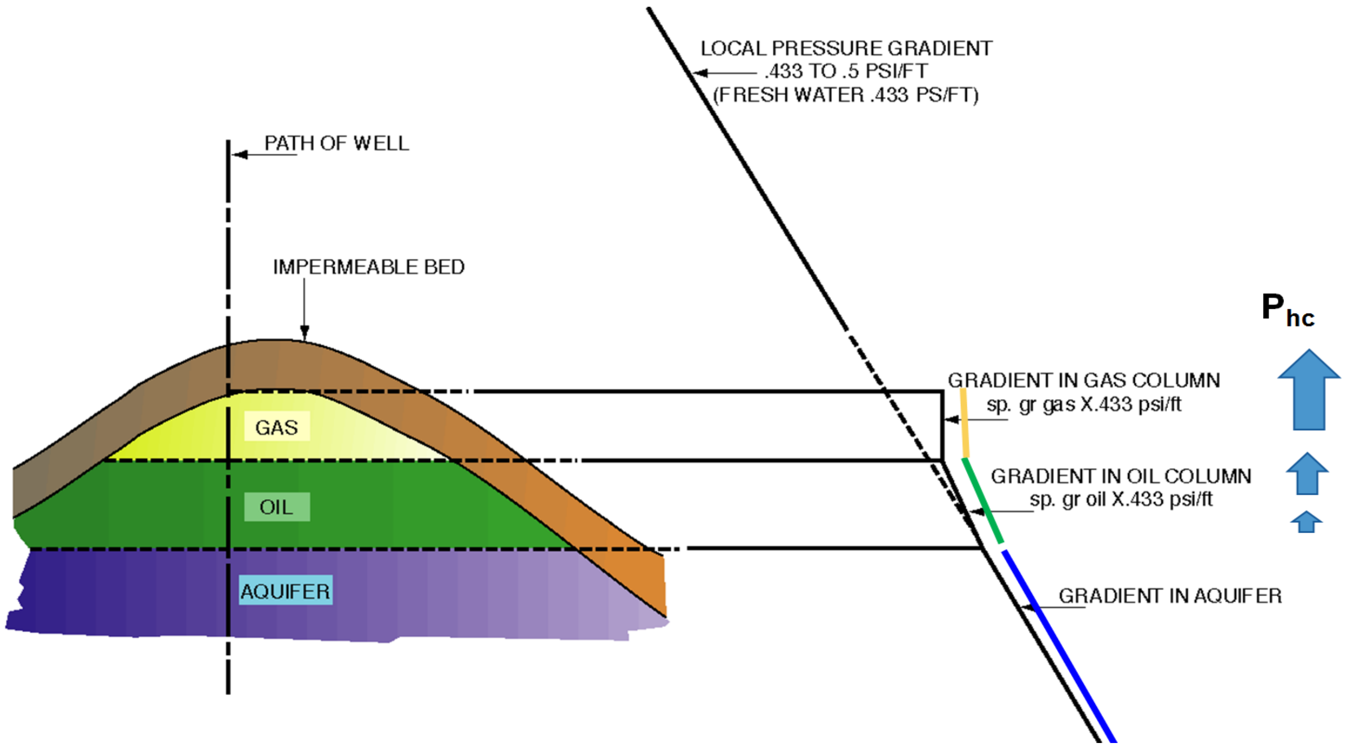


GOR Trends for Drive Mechanisms

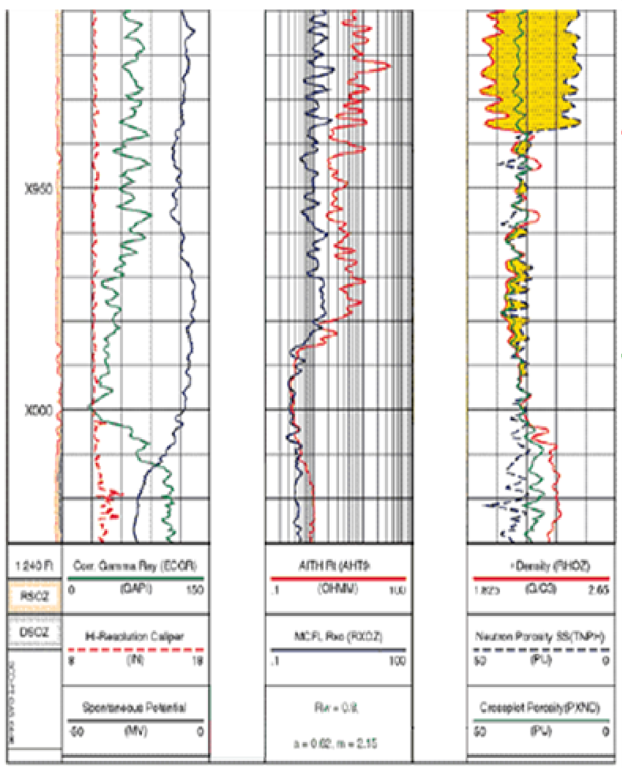


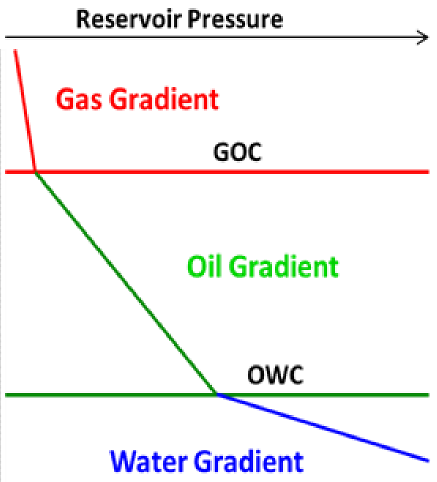


Hydrostatic Pressure and Pressure Distribution



Identifying Fluid Contact





Gradients in psi/m:

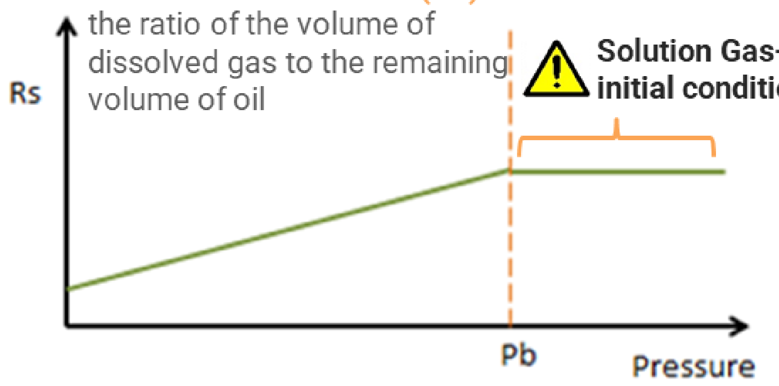
- Gas : 0.16 to 0.36 psi/m
- Oil : 0.88 to 1.18 psi/m
- Water : 1.420 to 1.509 psi/m

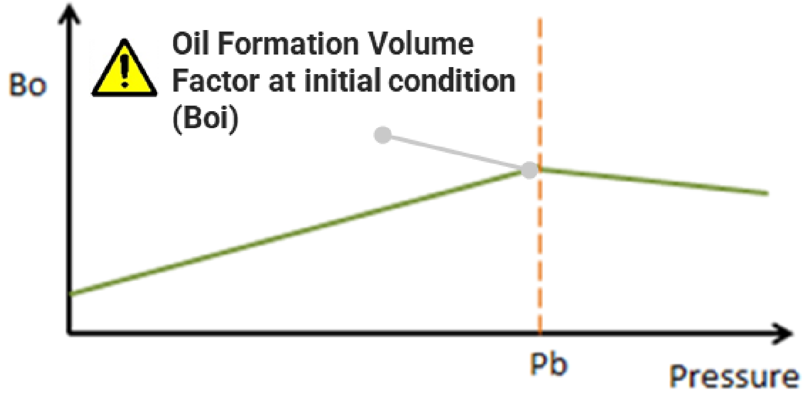
PVT Data

Understanding the effect of pressure toward hydrocarbon properties (Rs, Bo, Bg) and In-Place

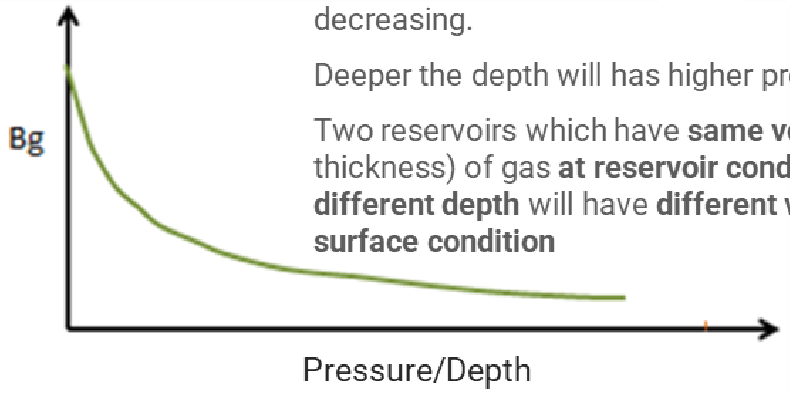
Solution Gas-Oil Ratio (Rs)

the ratio of the volume of dissolved gas to the remaining volume of oil





Bg vs Depth



Gas Formation Volume Factor (Bg)

The volume of gas is increasing while pressure is decreasing.

Deeper the depth will has higher pressure.

Two reservoirs which have **same volume** (area x thickness) of gas **at reservoir condition** but laid in **different depth** will have **different volume** of gas at **surface condition**

Oil Formation Volume Factor (Bo)

If the **reservoir pressure (Pr)** is equal to its hydrostatic pressure (virgin), then the reservoir pressure is also equal to bubble point pressure (Pb)

At the **initial contact of Gas-Oil**, the pressure is usually at **hydrostatic condition (virgin)**

→ **Hence the Bo is at initial condition (Boi)**

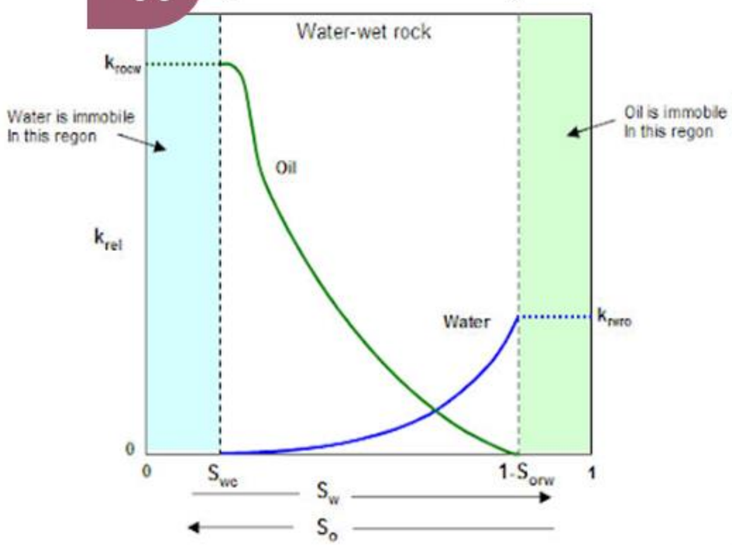
Important Parameters for estimating In-Place & Reserves

Relative Permeability

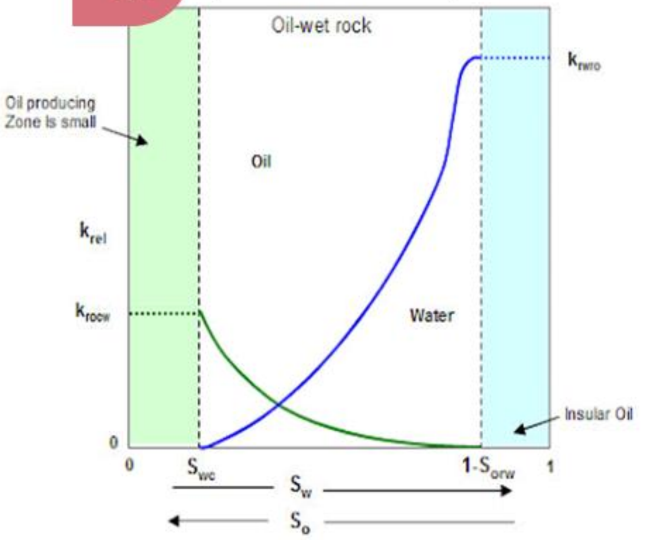
This data is typically a rare data, generated from Special Core Analysis (SCAL), conducted in Lab.

a CORE SCALE but it's applied to FIELD SCALE

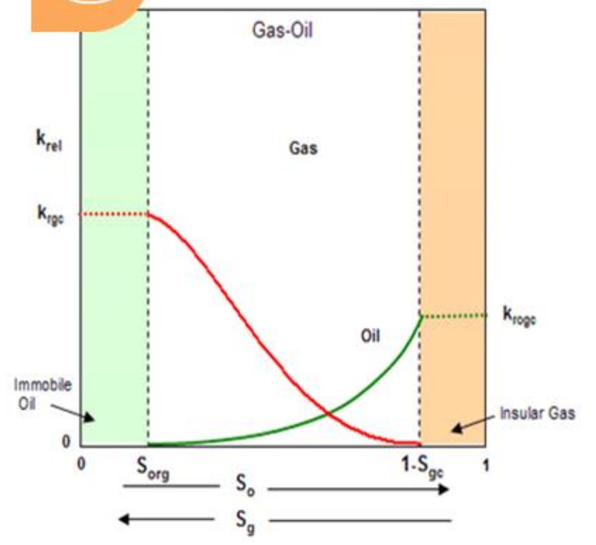
OIL-WATER Relative Permeability (Water-Wet Reservoir)



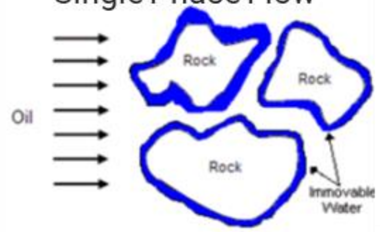
OIL-WATER Relative Permeability (Oil-Wet Reservoir)



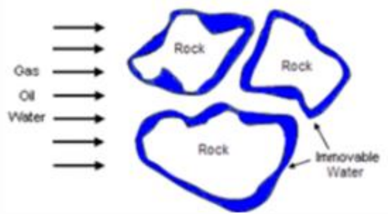
GAS-OIL Relative Permeability



Single Phase Flow



Multi Phase Flow



$$k_{ro} = \frac{k_o}{k}, k_{rw} = \frac{k_w}{k}, k_{rg} = \frac{k_g}{k}$$

Thus,

$$k_{ro} + k_{rw} + k_{rg} < 1$$

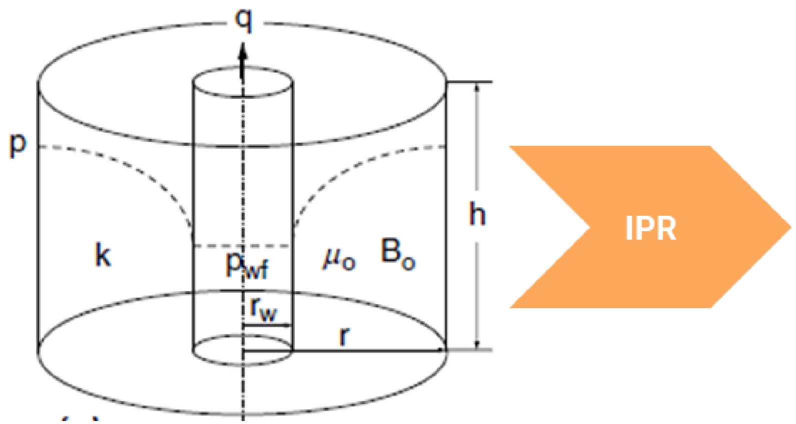
Why Relative Permeability is important?

- Fluid flow behavior through porous media
- Timing of water breakthrough
- Hydrocarbon recovery

Inflow Performance Relationship (IPR)

Understanding several factors that affect on reservoir deliverability

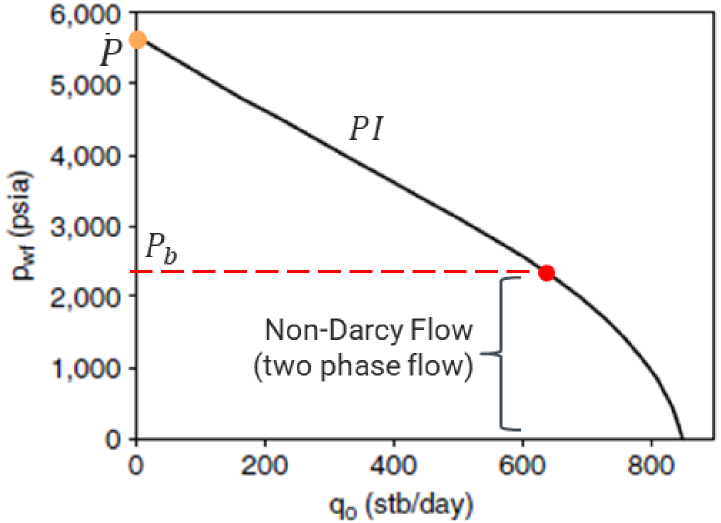
Radial Flow Model, $C_A = 31.6$



Fluid flow is easier to be observed under **Pseudo Steady State Condition**, where Reservoir Pressure is the average ($\bar{P}$), hence the flow equation is derived:

$$q = \frac{kh(\bar{P} - P_{wf})}{141.2 B_o u_o \left(\ln \frac{r_e}{r_w} - \frac{3}{4} + S\right)}$$

$$q = PI(\bar{P} - P_{wf})$$



Reservoir Deliverability depends on:

- Reservoir Pressure
- Payzone Permeability (k) & Thickness (h)
- The distance (r_e) & type of reservoir boundary (C_A)
- Wellbore radius (r_w)
- Near wellbore condition (Skin, S)
- Fluid Properties (Bo & viscosity, u)
- Relative Permeability (k_r)

OIL IPR

- Vogel
- Extended Vogel (Standing)
- Fetkovich
- PI Entry
- **Darcy**
- etc

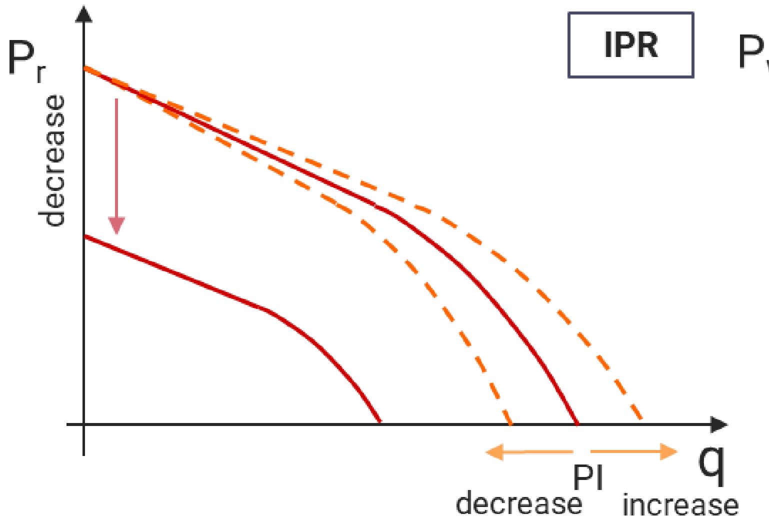
GAS IPR

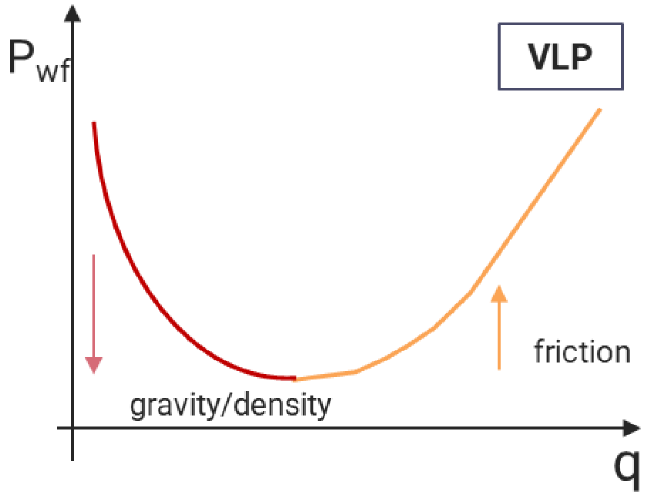
- Forcheimer
- Pseudo Forcheimer
- C & N
- **Jones**
- etc

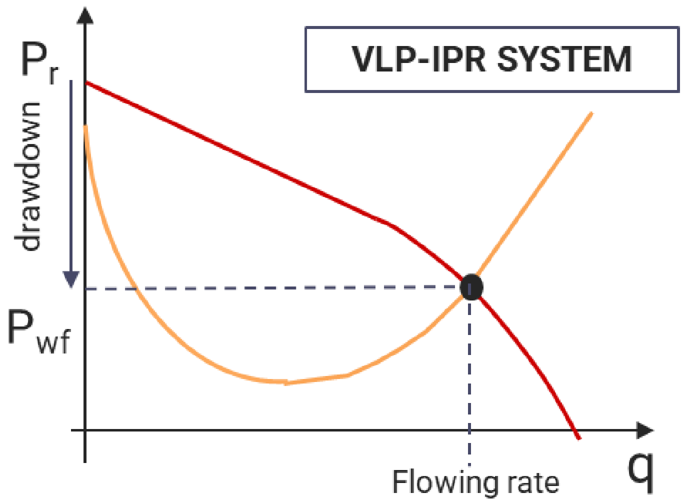
to construct IPR curve either use test data (known rates & pressures) or reservoir properties

Well-Reservoir Deliverability: Nodal Analysis

Understanding how reservoir fluid is flowing from the reservoir to the well up to surface

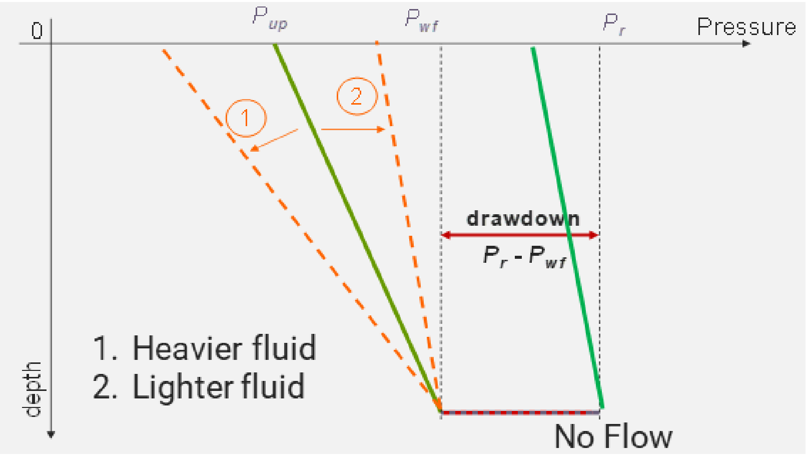






Vertical Lift Performance (VLP) depend on:

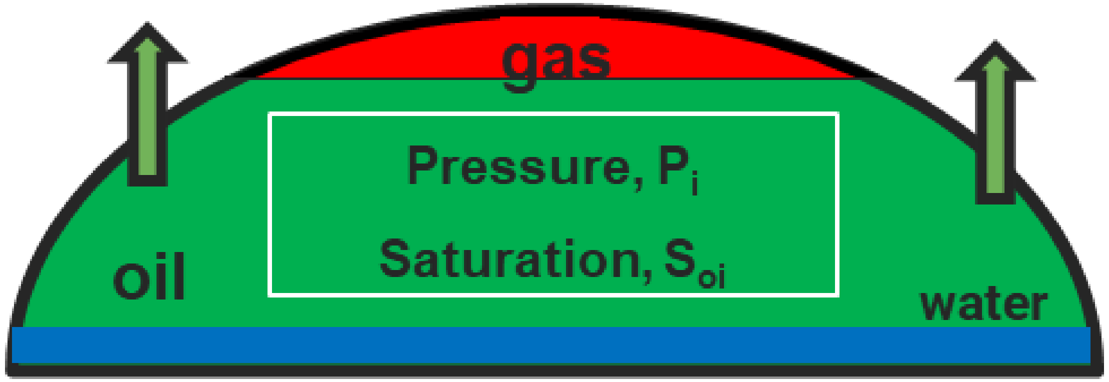
- Surface / Network Pressure
- Fluid Properties
- Flow regime inside & along the well
- Flowing velocity
- Tubing Size ID
- Tubing Roughness
- Temperature



a plot of VLP – IPR system is only capturing one time step, the curves will be changing over time.

Material Balance Approach

Reservoir as a Tank, total withdrawal volume shall be equal to total influx and/or fluid volume expansion (balance)



A = Penambahan akibat ekspansi minyak dan gas terlarut mula-mula

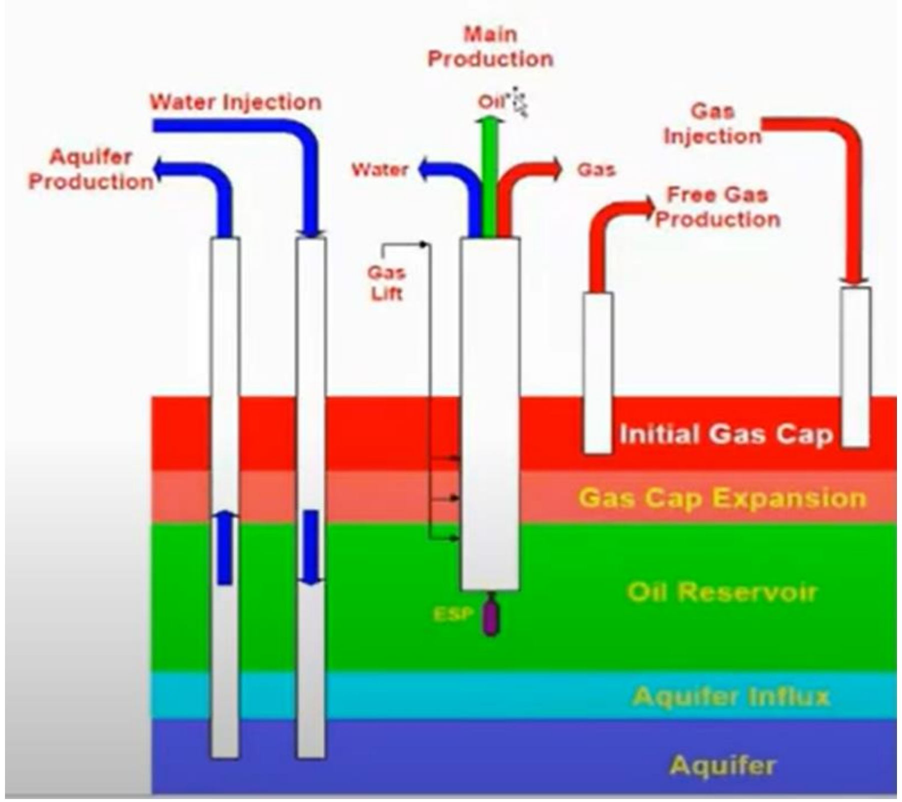
B = Penambahan akibat ekspansi Gas cap mula-mula

C = Penambahan akibat pengurangan HCPV karena kombinasi dari efek-efek penambahan Connate Water dan pengurangan volume pori reservoir

HCPV = Hydrocarbon Pore Volume

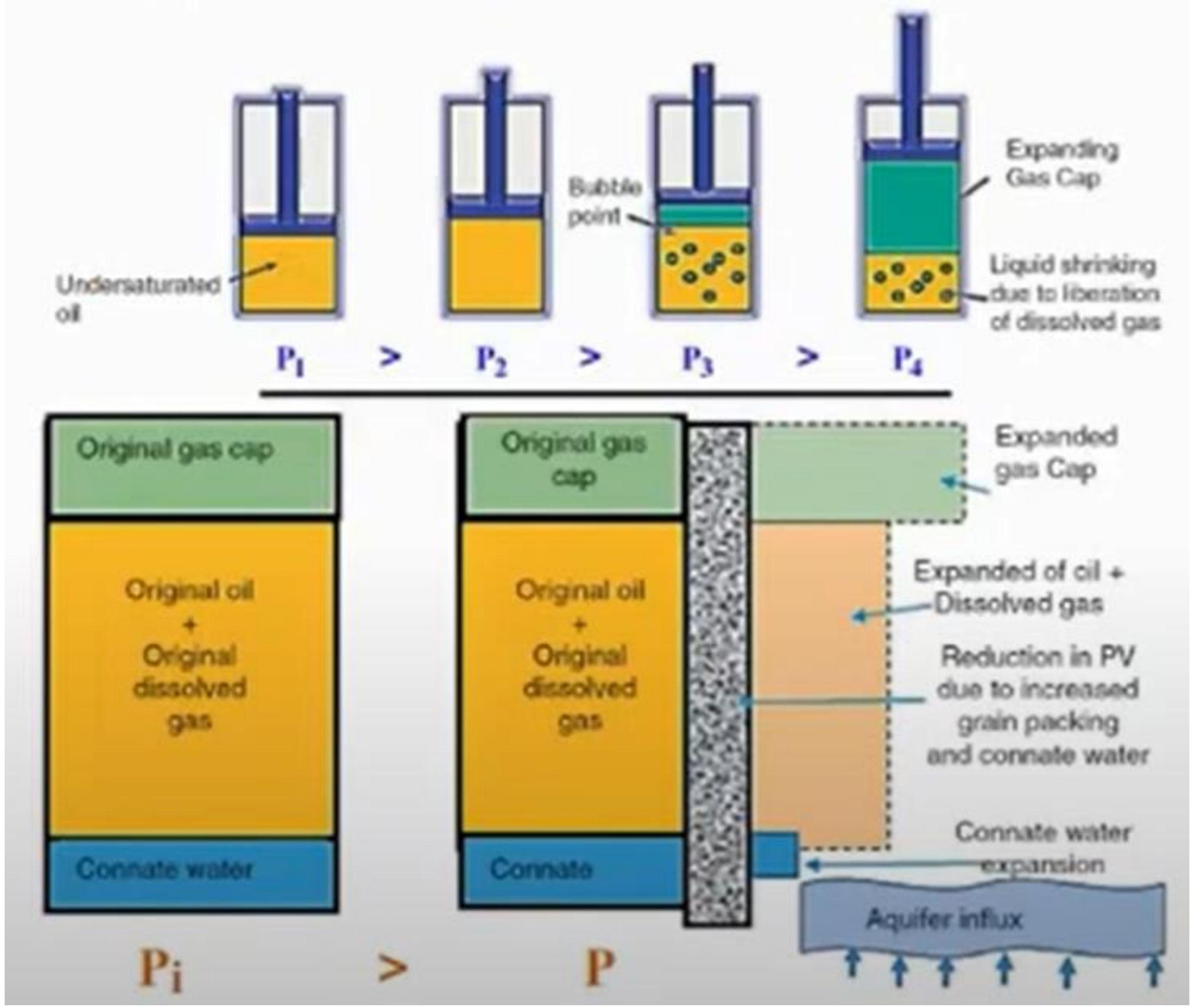
Material Balance Approach

TANK MODEL



Total undergroud withdrawal (rb)
= Expansion of the primary gas cap (rb)
+ Expansion of the original oil + original dissolved gas (rb)
+ Expansion of connate water + decrease in pore volume (rb)
+ water enroachment(rb)

Oil Material Balance System

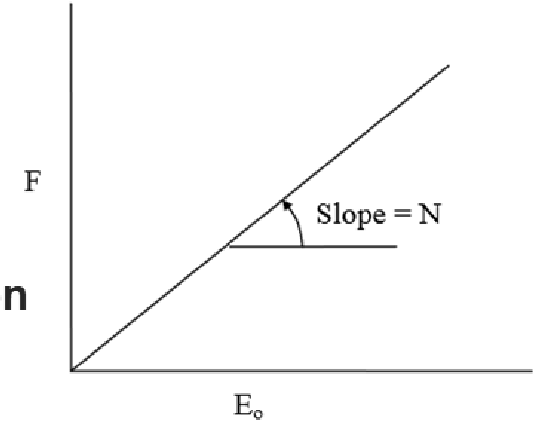


Straight Line Material Balance

Depletion Drive

$$F = NE_o$$

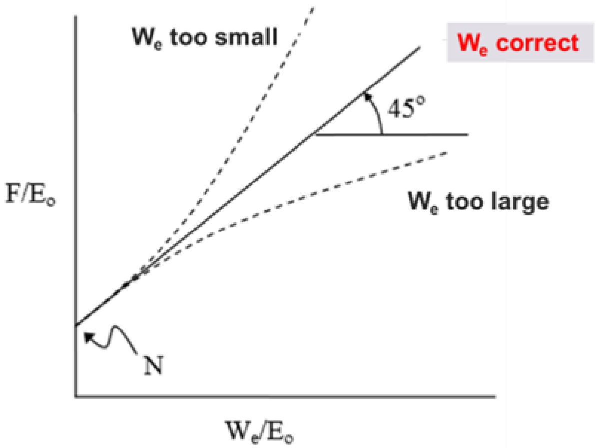
F = Underground Withdrawal
E_o = Oil and solution gas expansion



Water Drive

$$F = NE_o + W_e$$
$$\frac{F}{E_o} = N + \frac{W_e}{E_o}$$

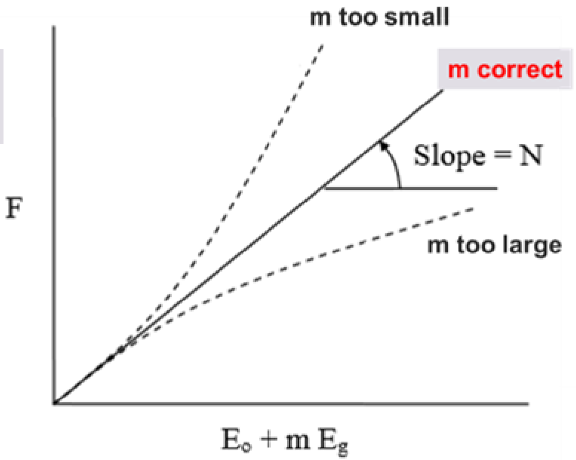
W_e = Water encroachment



Gas Cap Drive

$$F = N(E_o + mE_g)$$

m = ratio gas cap/oil in place
E_g = Gas cap expansion



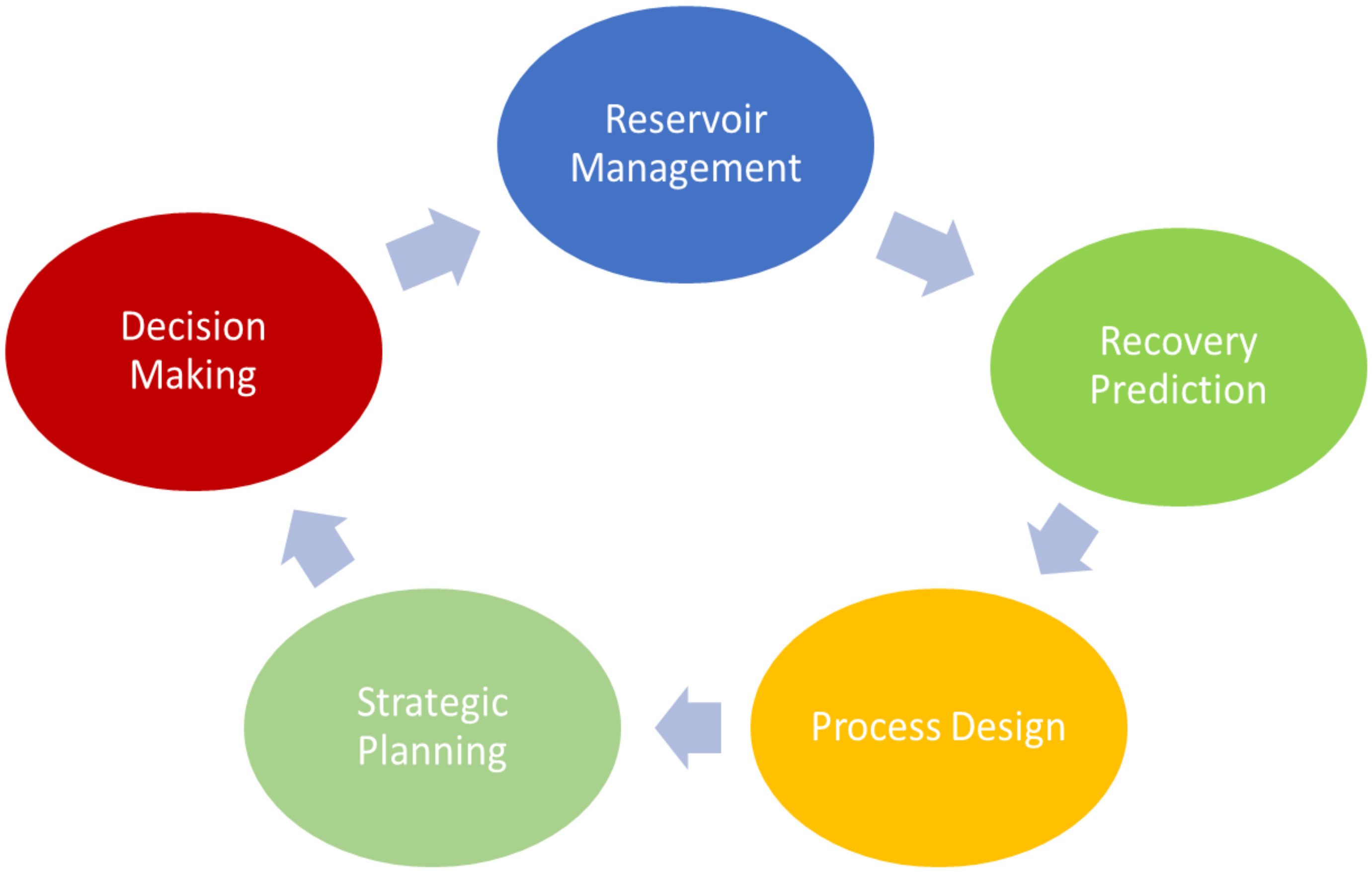
RESERVOIR SIMULATION

Reservoir Simulation

Purpose of Reservoir Simulation:

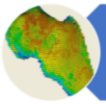
1. To model reservoir condition mathematically, by integrating all available data (geological, geophysical, petrophysical, & reservoir),
2. To get a better understanding on how reservoir behave,
3. And thus one could obtain a forecast of reservoir behavior, transalated as production profile.
4. And one could also perform & test optimization strategy to obtain the best recovery of a reservoir

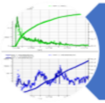
Reservoir Simulation is an indispensable tool for

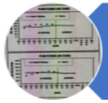


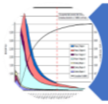
Numerical Simulation Approach

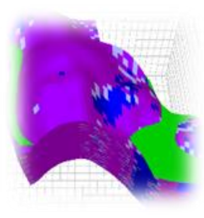
Reservoir is defined into grid cells, fluid flow through one cell to other cells is modeled using transmissibility equation

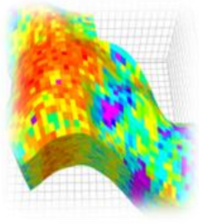

Initialization

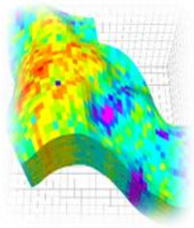

History matching


PI Matching

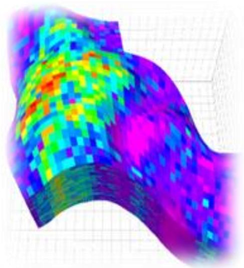

Forecasting Prediction


Rock Type/Facies w/ HC Contacts


NTG


Porosity

Phi – k Correlation

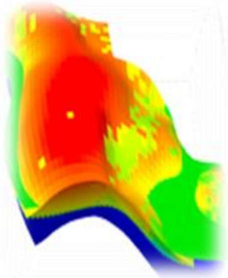

Permeability (k_h & k_v)

Inter Grid Transmissibility:

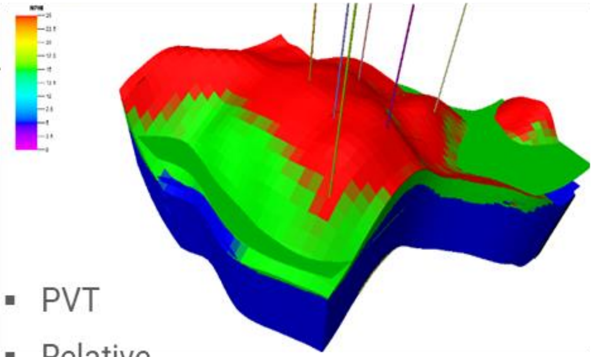
$$\nabla \cdot \left(\frac{K \cdot k_{rl}}{\mu_l B_l} \nabla p_l \right),$$

Where: $\lambda = \frac{k_r}{\mu B}$

- Upscaling
- J-Function


Initialization

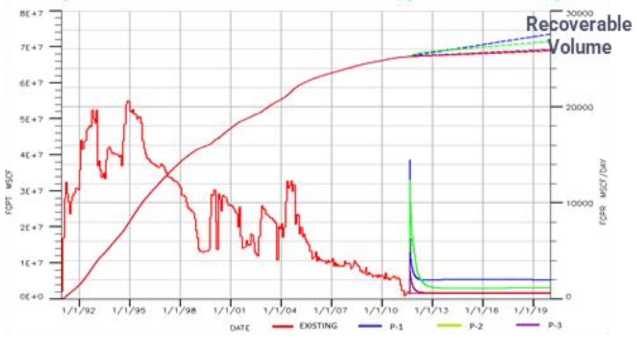
Dynamic Simulation



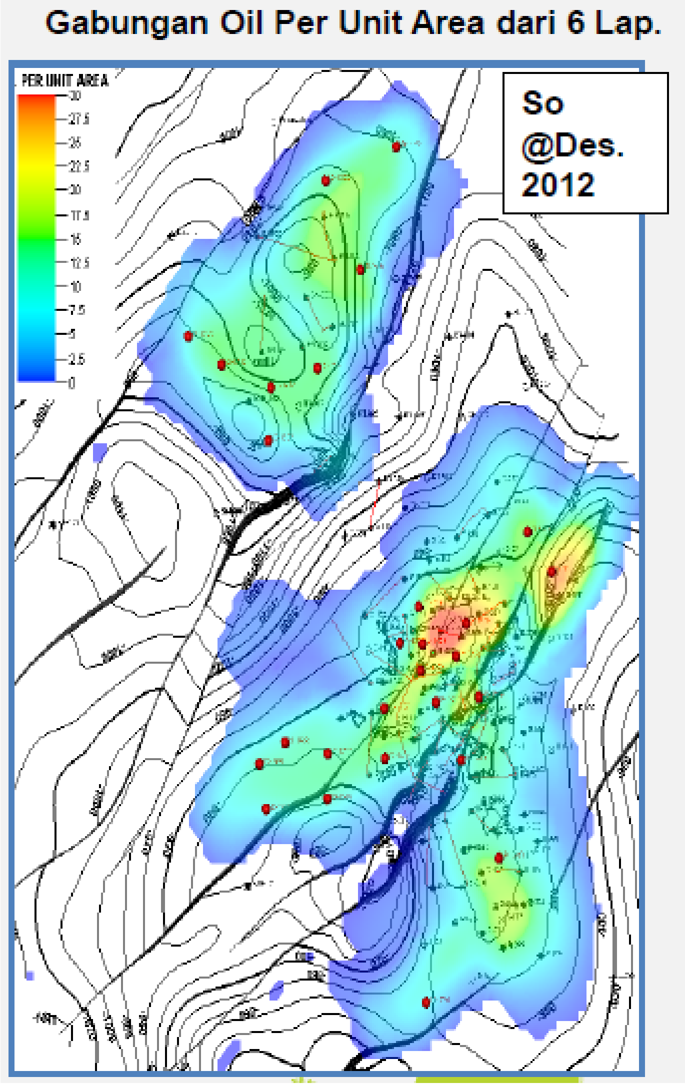
- PVT
- Relative Permeability

History Match (Pressure & Fluids)

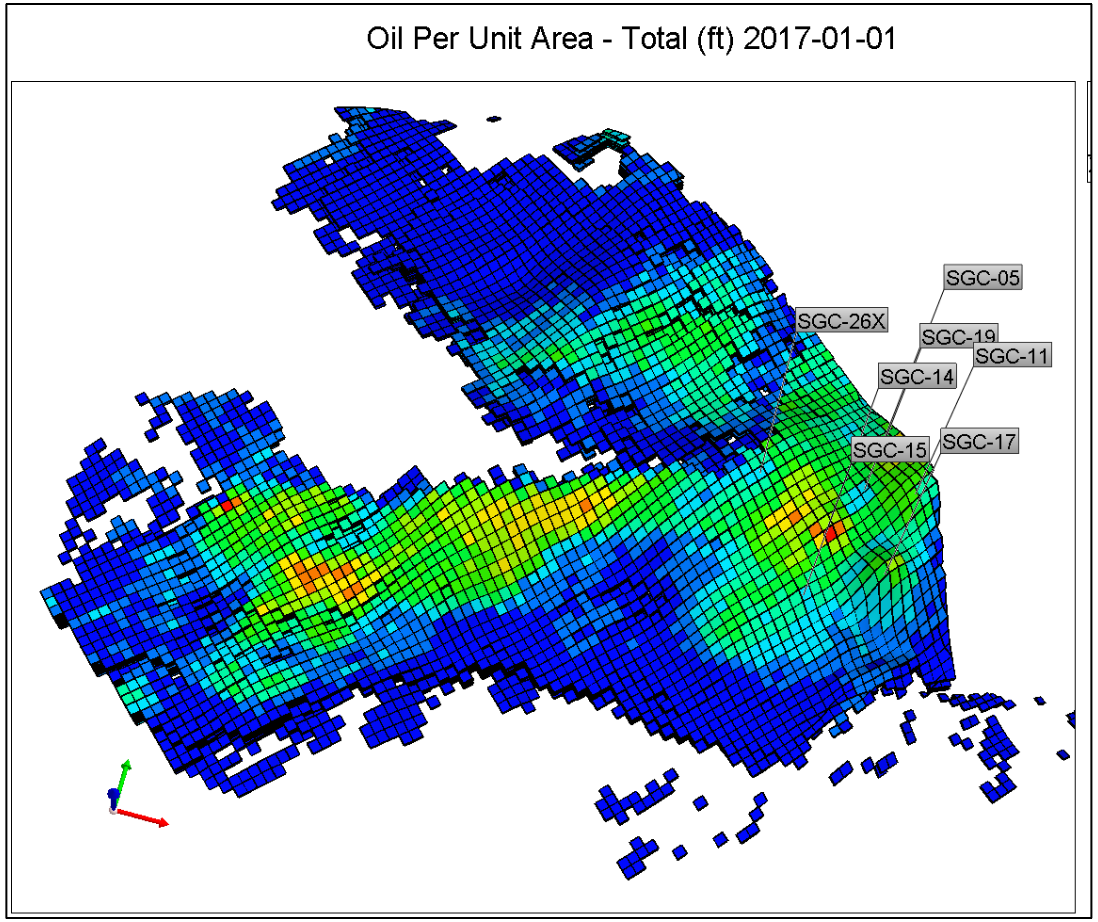
Forecast (Several Scenario)



Reservoir Simulation



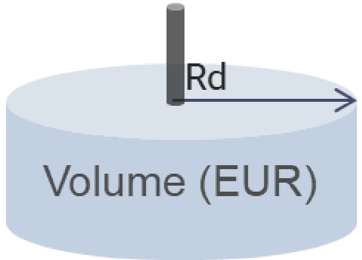
Saturation or Mobile oil map at the end of simulation to pinpoint infill location



Statistical Approach of Drainage Radius (Rd)

Using historical production data to generate a drainage value for each reservoir, statistical analysis performed on populated data

1 Derives Rd from Died Reservoir* (Cum. Prod. = EUR):



Rd for Gas

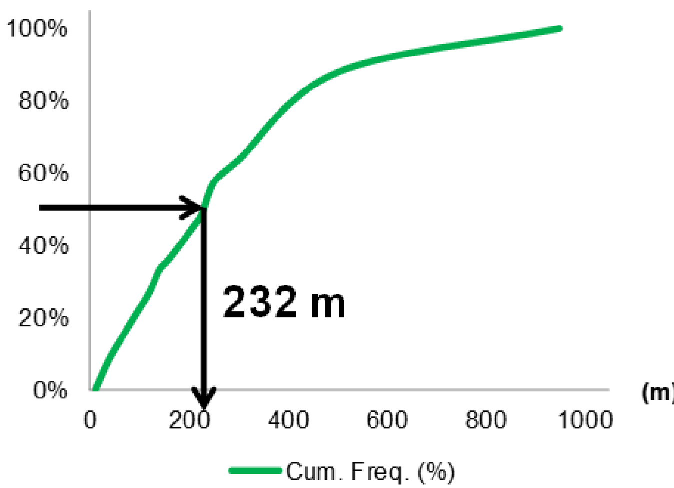
$$R_d = \sqrt{\frac{EUR \times B_g \times 10^9}{\pi \times HPM \times RF \times 35.31}}$$

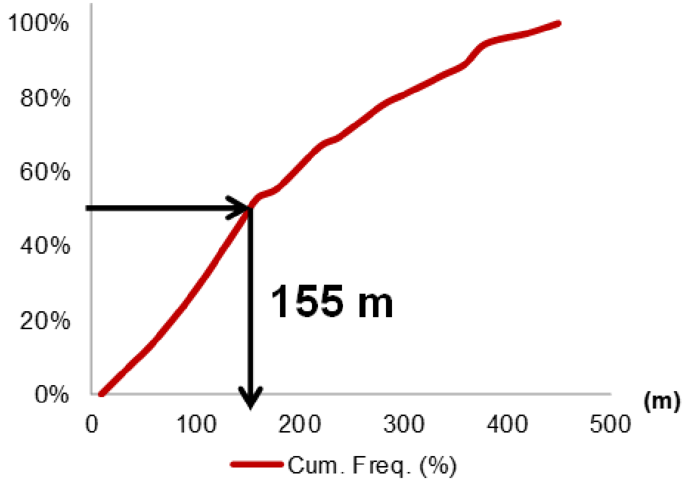
Rd for Oil

$$R_d = \sqrt{\frac{EUR \times B_o \times 10^6}{\pi \times HPM \times RF \times 6.29}}$$

Where: $HPM = h * (1 - Sw) * \varphi$

2 Populates the Rd** to find probabilistic parameter (P90, P50, P10)





⚠ **RF** is the most uncertain parameters in this approach

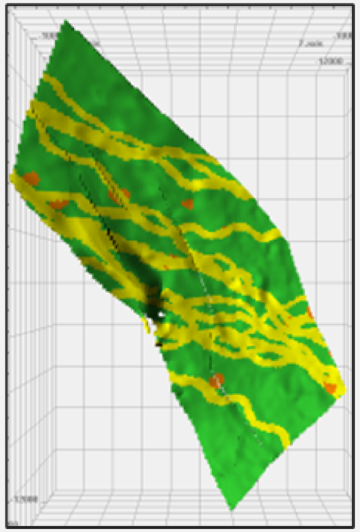
3 Calculates Connected Volume or EUR:

$$COIP/CGIP = \frac{\pi * (Rd)^2 * HPM}{Bo/Bg}$$

$$EUR = \frac{\pi * (Rd)^2 * HPM * RF}{Bo/Bg}$$

Type of Facies

- Channel
- Bar
- Shale



*Robust production allocation at reservoir level is a key!

**Reservoir is gathered based on facies or stratigraphic level (its homogeneities)

Decline Curve Analysis

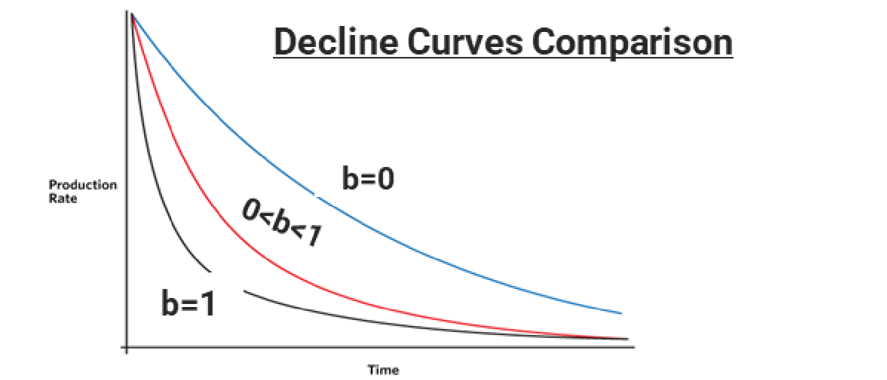
Using historical production trend by characterized its decline then predicts the future of production (forecast)

	b=0 Exponential	0<b<1 Hyperbolic	b=1 Harmonic
Rate: f (time)	$q = q_i\, e^{(-a\,t)}$	$q = \dfrac{q_i}{(1 + b\, a_i\, \Delta t)^{\left(\frac{1}{b}\right)}}$	$q = \dfrac{q_i}{(1 + a_i\, \Delta t)}$
Rate: f (cumulative)	$q = q_i - Q\, a$	$q^{(1-b)} = q_i^{\,(1-b)} - \dfrac{Q\, a_i(1-b)}{q_i^{\,b}}$	$q = q_i\, e^{\left(\frac{-Q\, a_i}{q_i}\right)}$
EUR	$Q_f = Q_i + \left[\dfrac{q_i - q_f}{a}\right]$	$Q_f = Q_i + \left[\dfrac{q_i^{\,b}}{a_i(1-b)}\left(q_i^{\,(1-b)} - q_f^{\,(1-b)}\right)\right]$	$Q_f = Q_{i+}\left[\dfrac{q_i}{a_i}\ln\left(\dfrac{q_i}{q_f}\right)\right]$

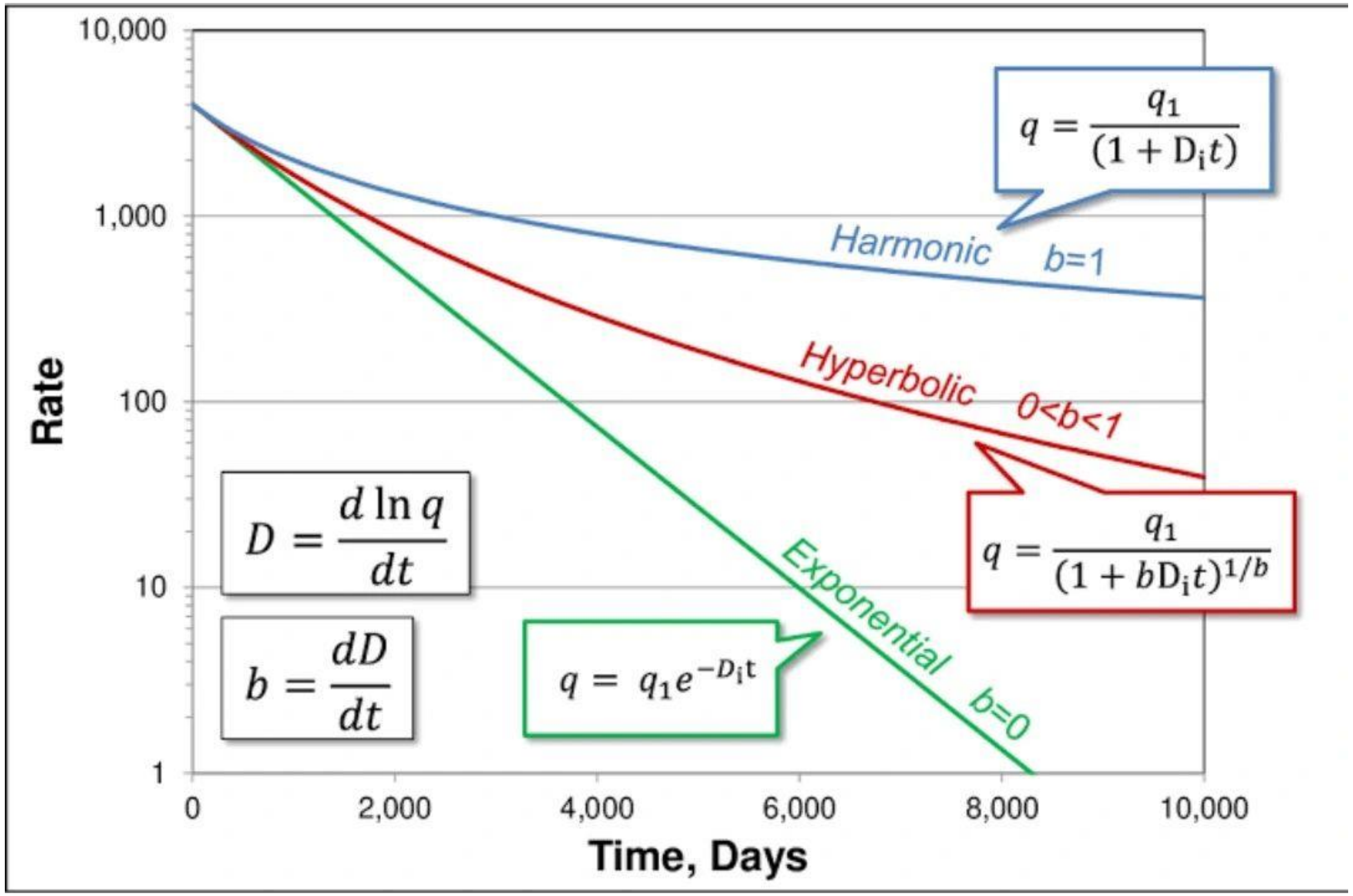
Where: a **: Constant Decline Rate,** b **Arps Constant**

⚠ There is empirical type curve for defining "the Arps*" or you may find it also by performing goal-seek analysis in Ms. Excel ☺

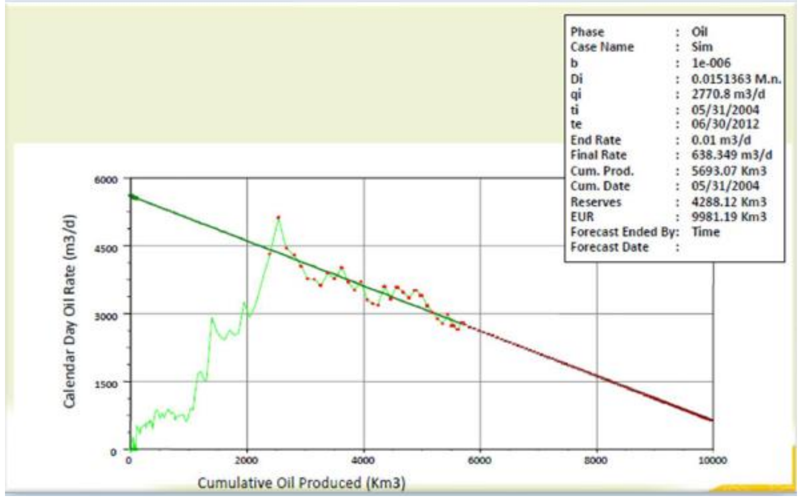
*J.J. Arps was an American geologist who published a mathematical relationship for the rate at which oil production from a single well declines over time (1945)

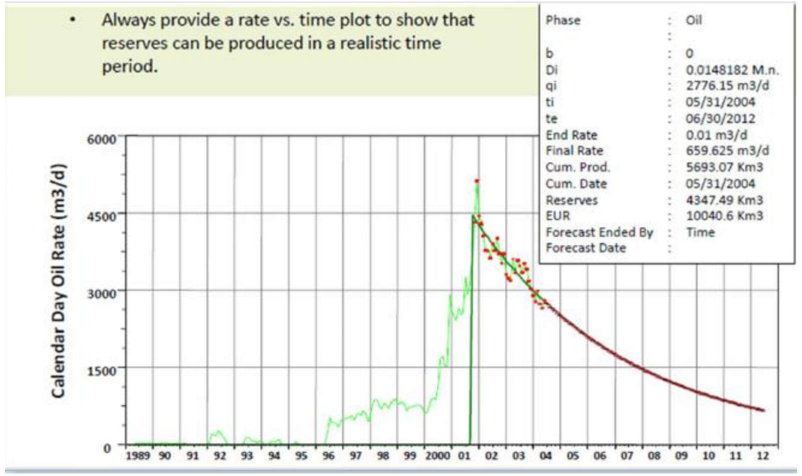


Decline Curve Analysis



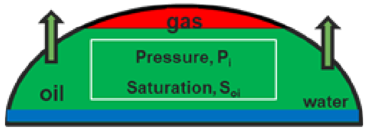
Example Exponential Decline

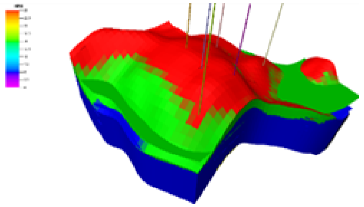


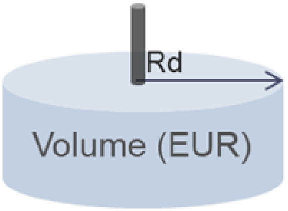


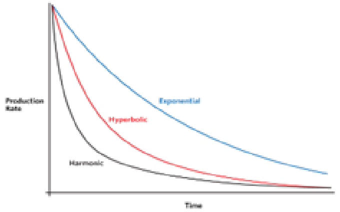
Summary for All Different Approach

The approach to estimate reserves is depend on the objective of study, type of reservoir, reservoir characteristics, the amount of data, data availability, project timeline, etc.





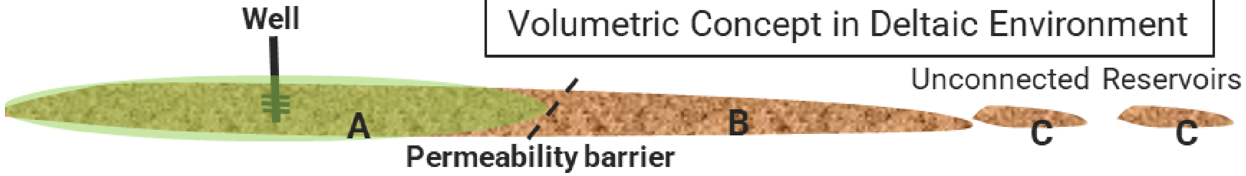




Material Balance	Numerical Simulation	Drainage Radius (Rd)	Decline Curve Analysis
Initialization: In-Place Dynamic ≤ In-Place Volumetric	Initialization: In-Place Dynamic ± In-Place Volumetric (~5% difference)	No initialization	No Initialization
History Match: Focus matching on Reservoir Pressure	History Match: Focus matching on Production Fluids	No History Match	Using historical data for fine tuning the decline/rate
Prediction/Forecast: Each Production Fluids & future Reservoir Pressure can be forecasted	Prediction/Forecast: Each Production Fluids & future Reservoir Pressure can be forecasted	Prediction/Forecast: Prediction result is in form of volume for HC fluids (either oil or gas)	Prediction/Forecast: The analysis for oil and gas reservoir is conducted separately
Spatial Information & Reservoir Heterogeneity can't be captured	Spatial Information & Reservoir Heterogeneities are well captured (different well location and penetration point will have different EUR result)	Grouping the populated data into different facies/rock type group or surface area and depth interval level may capture Reservoir Heterogeneity	Not honoring Spatial Information & Reservoir Heterogeneity hence can't predict EUR of new reservoir (reservoir with no production data)

The unconnected volume might be mapped in Geostatic Model. However to produce it, the reservoir have to be connected by a dedicated well, in which for many cases is not economic, due to usually small volume accumulation

Volumetric Concept in Deltaic Environment



IOIP = A + B + C | COIP = A | Reserves = COIP x RF

PERTAMINA


MENJADI SEBAIK-BAIK MANUSIA.
Rasulullah ﷺ bersabda yang artinya:
"Sebaik - baik manusia adalah yang paling bermanfaat bagi manusia."
(HR. Ahmad, ath-Thabrani, ad-Daruqutni. dihasankan oleh al-Albani didalam Shahihul Jami' No: 3289)

Terima Kasih

Ketulusan untuk Melayani