ژئومکانیک مخازن هیدروکربوری

Petroleum Geomechanics

آشنایی با سیالات در مخازن هیدروکربوری

Hasan Ghasemzadeh

https://wp.kntu.ac.ir/ghasemzadeh/

فهرست مطالب

- معرفی و ضرورت
- مخازن و سیالات آنها
- تنش و اندازه‌گیری آن
- فشار منفذی و داده های درون چاهی
- رفتار سنگ در مخازن و معیارهای گسیختگی
- خواص دینامیکی مخزن
- گسل ها و ناپایداری‌های مخزن
- شکافت هیدرولیکی
- مدل ژئومکانیکی
- پروژه

Petroleum Fluids
Phase Behavior and Basic Properties.

- Introduction.
- Petroleum reservoir fluids.
- Fluid phase behavior.
- Classification of reservoir fluids.
- Basic reservoir gas properties
- Basic reservoir oil properties.

سیال مخزن

مخلوطی از یک یا چندین ترکیب آلی
حالت های گاز، مایع، جامد و یا مخلوط آنها
دارای رفتاری چند فازی برحسب دما و فشار

نام تجاری سیالات و مشخصات آنها

Petroleum fraction	Approximate hydrocarbon range	Approximate boiling range	
		°C	°F
Light gases	C_2–C_4	−90 to 1	−130–30
Gasoline (light and heavy)	C_4–C_{10}	−1–200	30–390
Naphthas (light and heavy)	C_4–C_{11}	−1–205	30–400
Jet fuel	C_9–C_{14}	150–255	300–490
Kerosene	C_{11}–C_{14}	205–255	400–490
Diesel fuel	C_{11}–C_{16}	205–290	400–550
Light gas oil	C_{14}–C_{18}	255–315	490–600
Heavy gas oil	C_{18}–C_{28}	315–425	600–800
Wax	C_{18}–C_{36}	315–500	600–930
Lubricating oil	$>C_{25}$	>400	>750
Vacuum gas oil	C_{28}–C_{55}	425–600	800–1100
Residuum	$>C_{55}$	>600	>1100

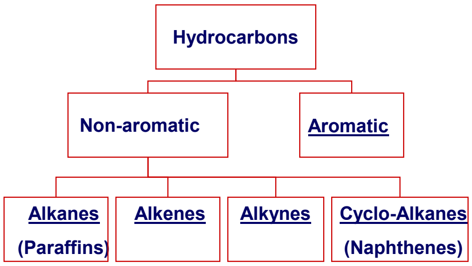
Petroleum Fluids

- **Reservoir fluids typically contains hundreds or thousands of hydrocarbon compounds and a few non-organic compounds.**
- **The physical properties of a reservoir fluid depends on composition, temperature and pressure.**
- **Natural gas is composed of mainly low-molecular weight alkanes (paraffins), CO_2, H_2S and N_2.**
- **Most crude oils are composed of higher-molecular weight hydrocarbon compounds (Aromatic and Naphthenes).**

Example Compositions

Hydrocarbons

$$C_nH_{2n+h}$$


Hydrocarbons

Non-aromatic

Aromatic

Alkanes (Paraffins)

Alkenes

Alkynes

Cyclo-Alkanes (Naphthenes)

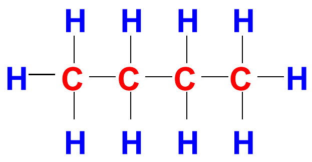
Petroleum Fluids – Example Compositions

Component	Dry Gas	Wet Gas	Gas Condensate	Near-Critical Oil	Volatile Oil	Black Oil
CO_2	0.10	1.41	2.37	1.30	0.93	0.02
N_2	2.07	0.25	0.31	0.56	0.21	0.34
C_1	86.12	92.46	73.19	69.44	58.77	34.62
C_2	5.91	3.18	7.80	7.88	7.57	4.11
C_3	3.58	1.01	3.55	4.26	4.09	1.01
i-C_4	1.72	0.28	0.71	0.89	0.91	0.76
n-C_4		0.24	1.45	2.14	2.09	0.49
i-C_5	0.50	0.13	0.64	0.90	0.77	0.43
n-C_5		0.08	0.68	1.13	1.15	0.21
$C_{6(s)}$		0.14	1.09	1.46	1.75	1.61
C_{7+}		0.82	8.21	10.04	21.76	56.40
Properties						
$M_{C_{7+}}$		130	184	219	228	274
$\gamma_{C_{7+}}$		0.763	0.816	0.839	0.858	0.920
K_{wC_7}		12.00	11.95	11.98	11.83	11.47
GOR, scf/STB	∞	105,000	5,450	3,650	1,490	300
OGR, STB/MMscf	0	10	180	275		
γ_{API}		57	49	45	38	24
γ_g		0.61	0.70	0.71	0.70	0.63
p_{sat}, psia		3,430	6.560	7,015	5,420	2,810
B_{sat}, ft^3/scf or bbl/STB		0.0051	0.0039	2.78	1.73	1.16
ρ_{sat}, lbm/ft^3		9.61	26.7	30.7	38.2	51.4

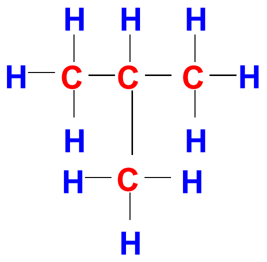
Alkanes (Paraffins)

Structure Formula

C_nH_{2n+2}



n-C_4H_{10} : normal-butane

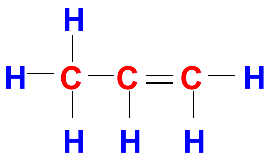


i-C_4H_{10} : iso-butane

Alkenes (Olefins)

Structure Formula

C_nH_{2n}



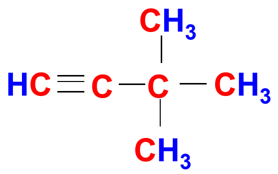
C_3H_6 : propene

Alkenes are seldom found in reservoir fluids due to their unstable nature

Alkynes

Structure Formula

C_nH_{2n-2}



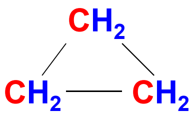
C_6H_{10} : Heksyne

Alkynes are seldom found in reservoir fluids due to their unstable nature

Cyclo-alkanes (Naphthenes)

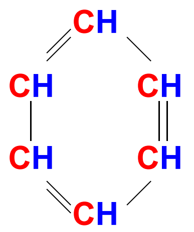
Structure Formula

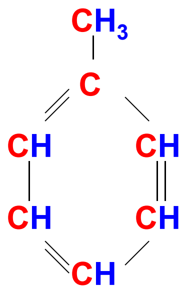
C_nH_{2n}



C_3H_6 : cyclo-butane

Aromatics





Benzene

Tuolene

Fluid Phase Behavior

All substances can occur in three states (phases):

1. **Vapor**
2. **Liquid**
3. **Solid**

***"Thermodynamic Equilibrium"*:**

- **No net mass transfer between the phases.**
- **Temperature and pressure of the co-existing phases are the same.**
- **The chemical potential of each component in each phase are equal.**
- **The system attains it minimum energy level.**

Gibbs Phase Rule

$$F = n - P + 2$$

- **Single-Component Systems.**
- **Two-Component Systems.**
- **Multi-Component Systems.**
- **Retrograde Condensation.**

Gibbs Phase Rule

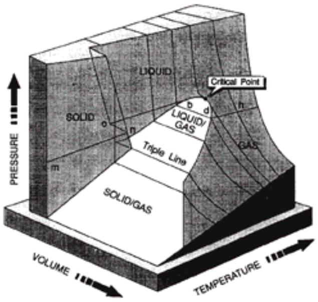
$$F = n - P + 2$$

- **F = Degrees of freedom (number of independent variables).**
- **n = Number of components.**
- **P = Number of phases.**

- *Intensive thermodynamic variables* such as temperature, pressure, composition, and density, do not depend upon the extent of the system.
- *Extensive variables* such as flow rate, total mass, or liquid volume depends upon the extent of the system.

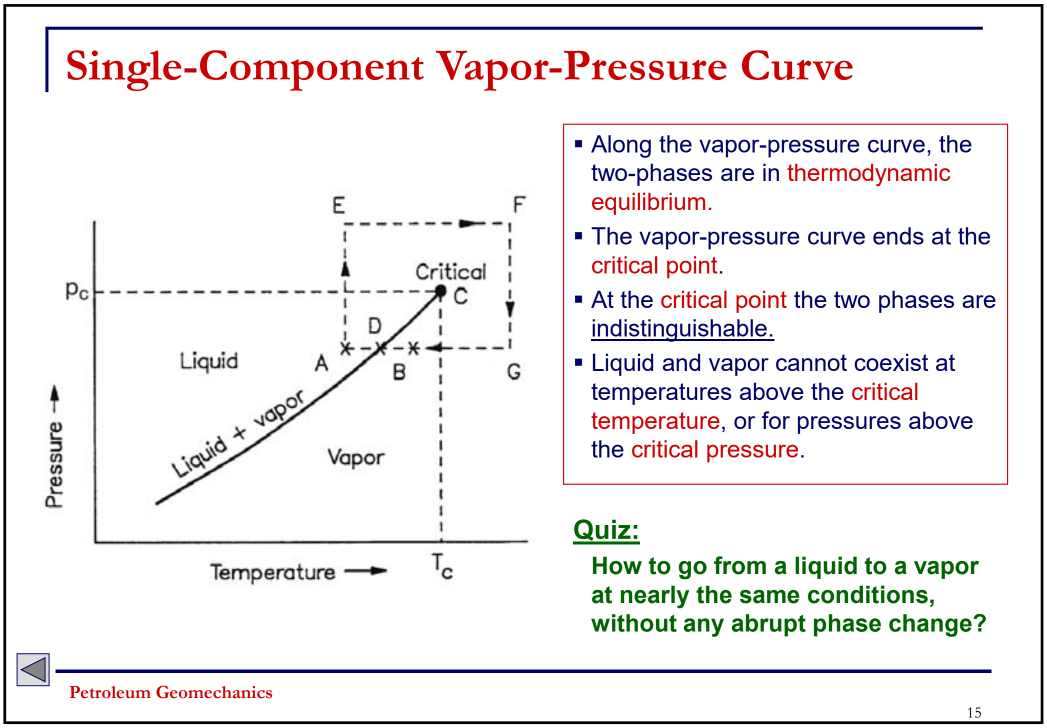
Single-Component Phase Behavior

$$F = 1 - P + 2$$



- Vapor curve (p-T diagram).
- Phase transition (p-V diagram).

- For a single-phase, single-component system **F = 2**, and the phase behavior is completely determined by pressure ***and*** temperature (or pressure and volume, at a given temperature).
- For a two-phase, single-component system **F = 1**, and pressure ***or*** pressure needs to be specified to determine the system.
- Vapor-Liquid Equilibrium (VLE) occurs only at the Vapor Pressure, which is a unique function of temperature that culminates at the Critical Point.

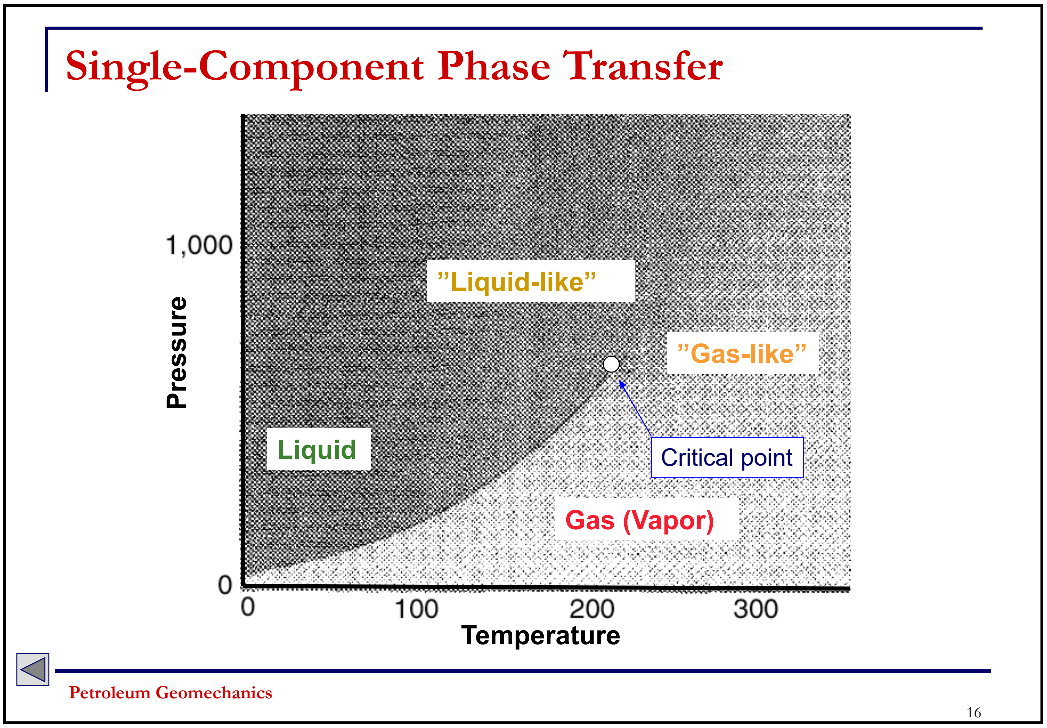


Single-Component Vapor-Pressure Curve

- Along the vapor-pressure curve, the two-phases are in thermodynamic equilibrium.
- The vapor-pressure curve ends at the critical point.
- At the critical point the two phases are indistinguishable.
- Liquid and vapor cannot coexist at temperatures above the critical temperature, or for pressures above the critical pressure.

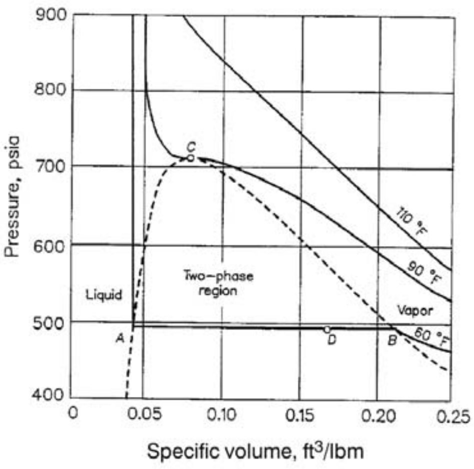
Quiz:

How to go from a liquid to a vapor at nearly the same conditions, without any abrupt phase change?



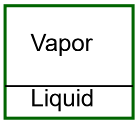
Single-Component Phase Transfer

Single-Component Pressure-Volume Curve

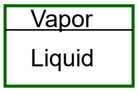


- In a single-component system, the transition from vapor to liquid takes place at a constant pressure.

Quiz:



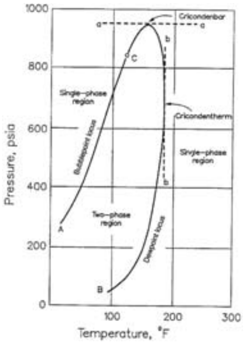
V = V1
T = T1
P = P1
$\rho_o = \rho 1$



V < V1
T = T1
P = ?
ρ_o = ?

Two-Component Phase Behavior

$$F = 2 - P + 2$$



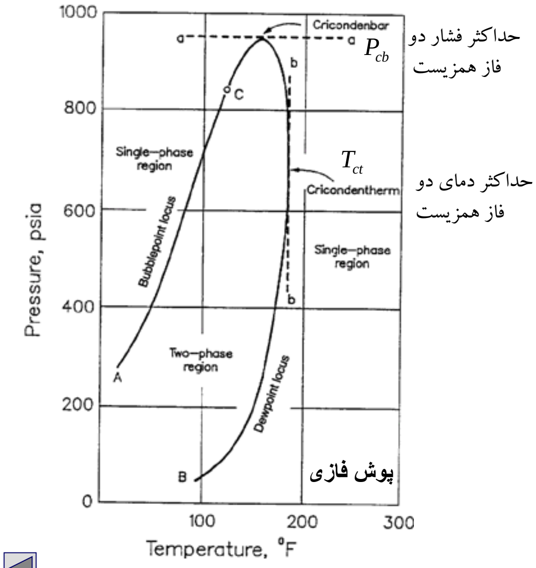
- p-T diagram
- p-V diagram
- p-x diagram

Equilibrium K-Values

$$K_i \equiv y_i / x_i$$

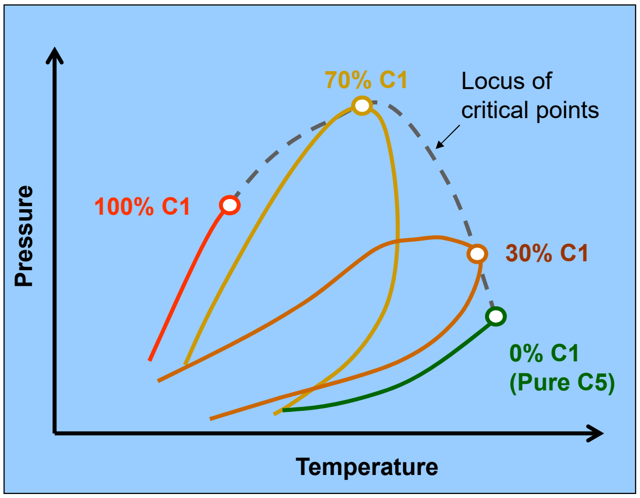
- For a single-phase, two-component system, **F = 3**, and the phase behavior is completely determined by pressure, temperature and composition.
- For a two-phase, two-component system, **F = 2** and in addition to composition, either pressure ***or*** temperature must to be specified to determine the system.
- In going from a single- to a two-component system, the saturated p-T projection is now represented by a phase envelope, rather than a single vapor-pressure curve.

Two-Component Phase Envelope



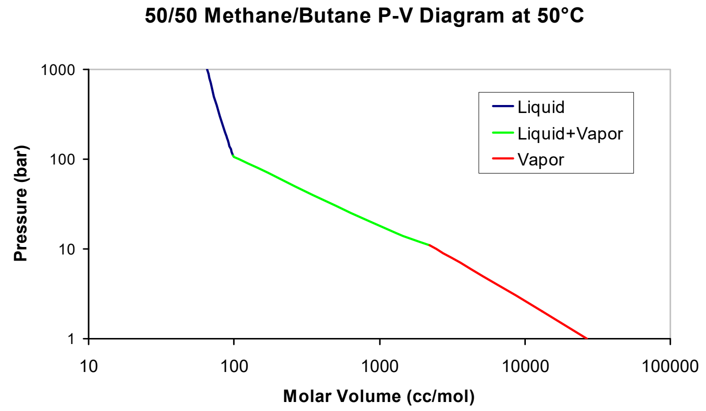
- In going from one to two (or more) components, the P-T Diagram (at constant composition) goes from a Vapor Pressure Curve to a Two-Phase Envelope.
- Two-phase envelopes always consist of Bubble Point and Dew Point surfaces, which meet at Critical Points. At the critical point, the phases are indistinguishable.
- Cricondentherm = The highest temerature at which two phases can co-exist
- Cricondenbar = The highest pressure at which two phases can co-exist

Phase Diagram for Various C_1-C_5 Mixtures



- The shape of the phase diagram is dependent on the fluid composition.
- The critical temperature of the mixture is always between the critical temperatures of the pure components
- The critical pressure of the mixture is usually higher than the critical pressure of the pure components.
- In general, the bigger difference between the pure components, the higher the critical pressure will be.

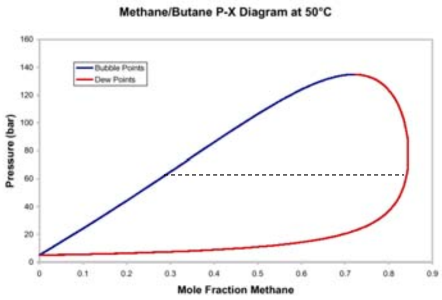
Two-Component p-V Diagram



50/50 Methane/Butane P-V Diagram at 50°C

- At constant temperature and composition, the pressure of a two-phase, multi-component system decreases as the volume increases (whereas, for a 1-component system, it stays constant)

Two-component p-x diagram



Methane/Butane P-X Diagram at 50°C

- For a 2-component system at constant temperature, the P-x Diagram uniquely defines the two-phase envelope of pressures and compositions.
- Equilibrium Compositions are given by the Tie Lines that connect bubble points to dew points at constant pressure.

Quiz:

- What is the equilibrium gas and liquid composition for a 50-50 mixture of C1-C4 mixture at 50 C and 60 bara?

Equilibrium K-Values

$$K_i \equiv y_i / x_i$$

- y_i = mole fraction of component *i* in the vapor phase
- x_i = mole fraction of component *i* in the liquid phase

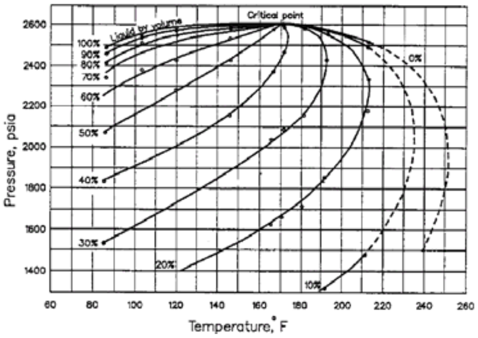
- Equilibrium K-values are a function of pressure, temperature and overall composition.
- K-values can be estimated by correlations, or by satisfying the equal-fugacity constraint with an Equation of State (EoS) model.

Binary Mixture Example

Figure

Multi-Component Phase Behavior

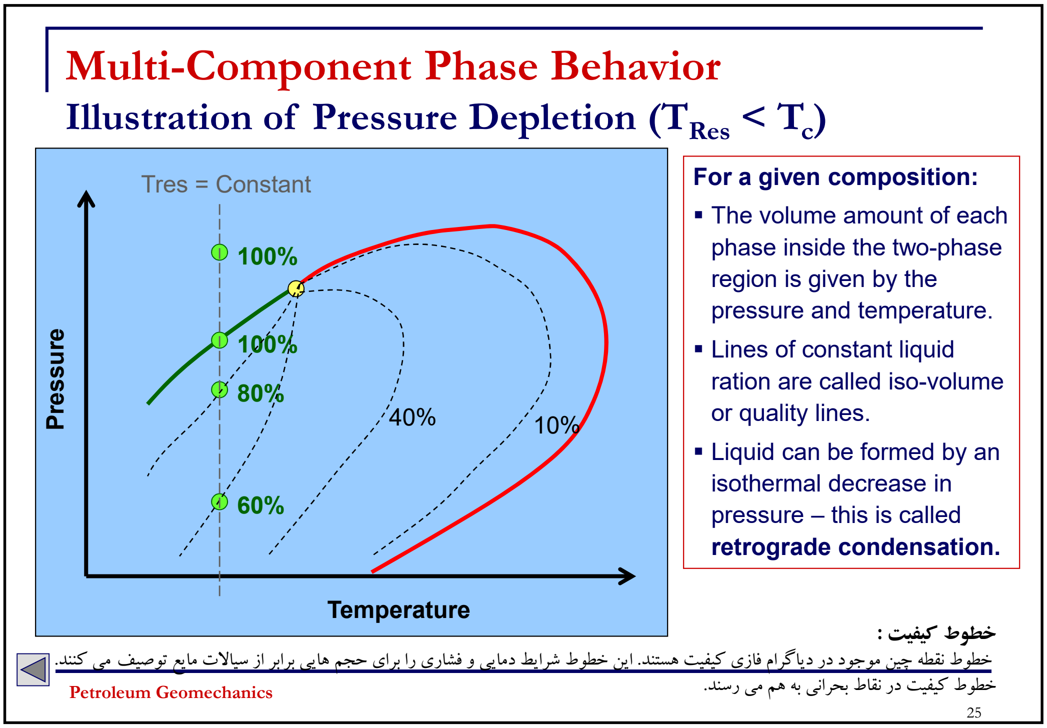
$$F = n_c - P + 2$$



PT-diagram for gas condensate fluid (after Katz et. al) showing lines of constant liquid percentage (quality lines).

- Multi-component constant-composition P-T and P-V Diagrams remain qualitatively similar to those of 2-component systems.
- Constant-temperature P-x Diagrams also remain similar, but are no longer unique and no longer define equilibrium tie lines. Also, the critical point no-longer coincides with the cricondenbar.

Illustration: Pressure Depletion



Multi-Component Phase Behavior

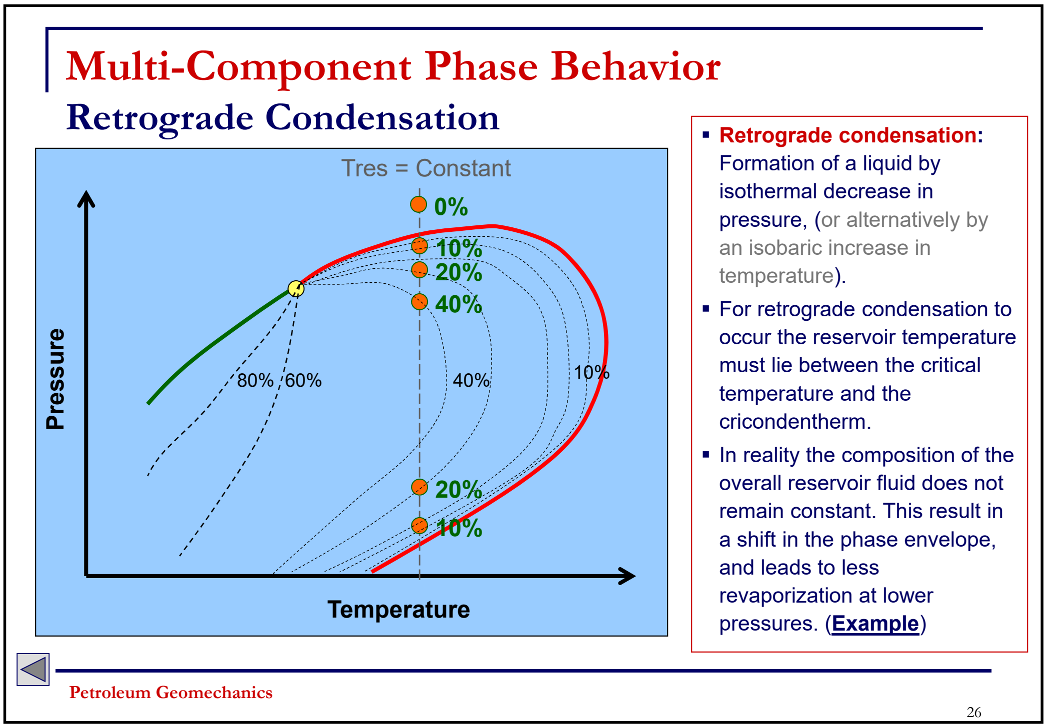
Illustration of Pressure Depletion ($T_{Res} < T_c$)

For a given composition:

- The volume amount of each phase inside the two-phase region is given by the pressure and temperature.
- Lines of constant liquid ration are called iso-volume or quality lines.
- Liquid can be formed by an isothermal decrease in pressure – this is called **retrograde condensation.**

خطوط کیفیت :

خطوط نقطه چین موجود در دیاگرام فازی کیفیت هستند. این خطوط شرایط دمایی و فشاری را برای حجم هایی برابر از سیالات مایع توصیف می کنند.
خطوط کیفیت در نقاط بحرانی به هم می رسند.



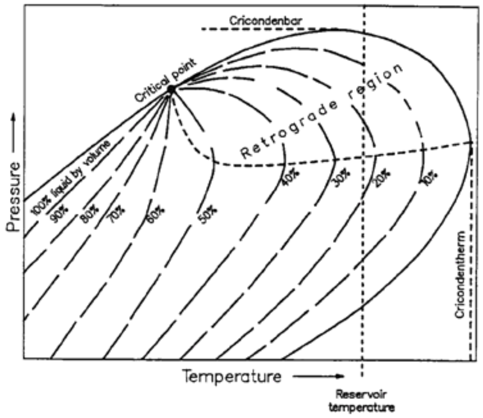
Multi-Component Phase Behavior

Retrograde Condensation

- **Retrograde condensation**: Formation of a liquid by isothermal decrease in pressure, (or alternatively by an isobaric increase in temperature).
- For retrograde condensation to occur the reservoir temperature must lie between the critical temperature and the cricondentherm.
- In reality the composition of the overall reservoir fluid does not remain constant. This result in a shift in the phase envelope, and leads to less revaporization at lower pressures. (**Example**)

Retrograde Condensation

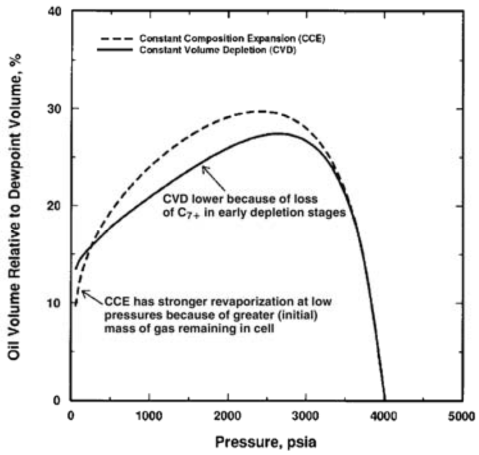
"Constant Composition" Analysis



- Retrograde condensation: Formation of a liquid by isothermal decrease in pressure, (or alternatively by an isobaric increase in temperature).
- For retrograde condensation to occur the reservoir temperature must lie between the critical temperature and the cricondentherm.
- In reality the composition of the overall reservoir fluid does not remain constant. This result in a shift in the phase envelope, and leads to less revaporization at lower pressures. (Example)

Retrograde Liquid Dropout

Constant Composition vs. Constant Volume



CVD lower because of loss of C_{7+} in early depletion stages

CCE has stronger revaporization at low pressures because of greater (initial) mass of gas remaining in cell

Classification of Reservoir Fluid Systems

Classifications:

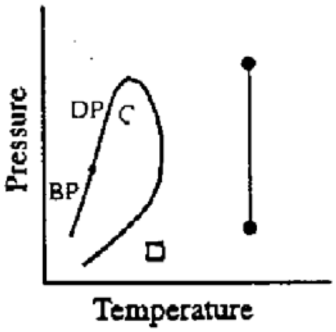
1. **Dry Gas.**
2. **Wet Gas.**
3. **Gas Condensate.**
4. **Volatile Oil.**
5. **Black Oil.**

Example compositions

The classification of fluid reservoir systems is determined by:

- **The location of the reservoir temperature with respect to the critical temperature and cricondentherm.**
- **Location of the first-stage separator pressure and temperature with respect to the phase diagram of the reservoir fluid.**

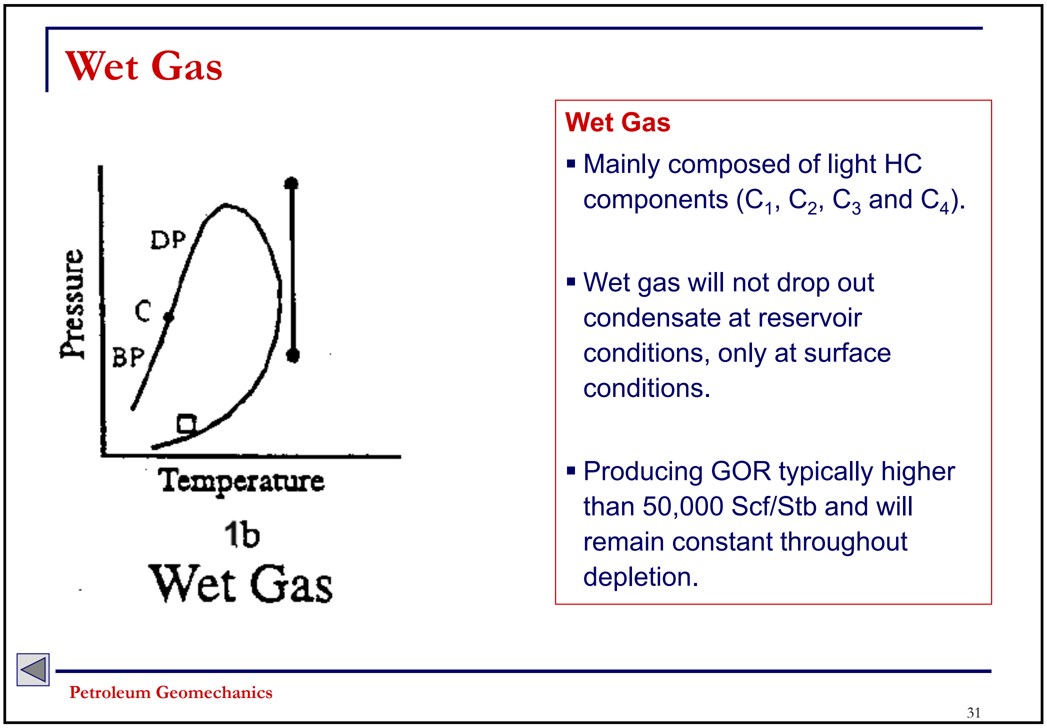
Dry Gas



1a
Dry Gas

Dry Gas

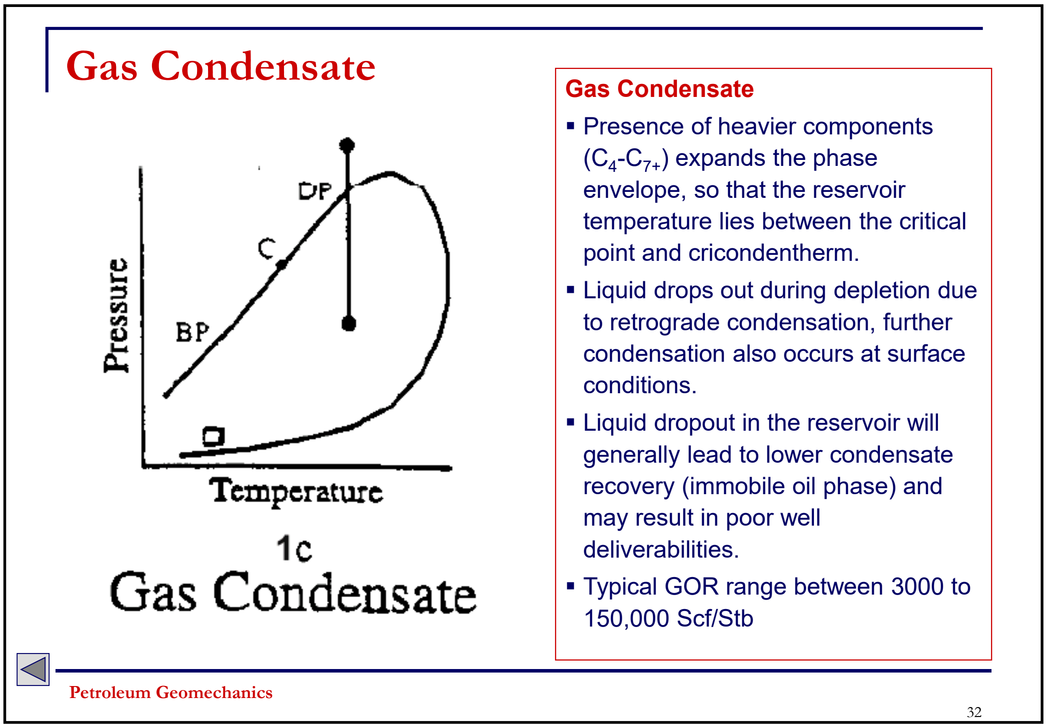
- Mainly composed of C_1 in addition to non-HC components such as N_2 and CO_2
- The gas remains single-phase from the reservoir to surface conditions (no condensate drop-out).



Wet Gas

Wet Gas

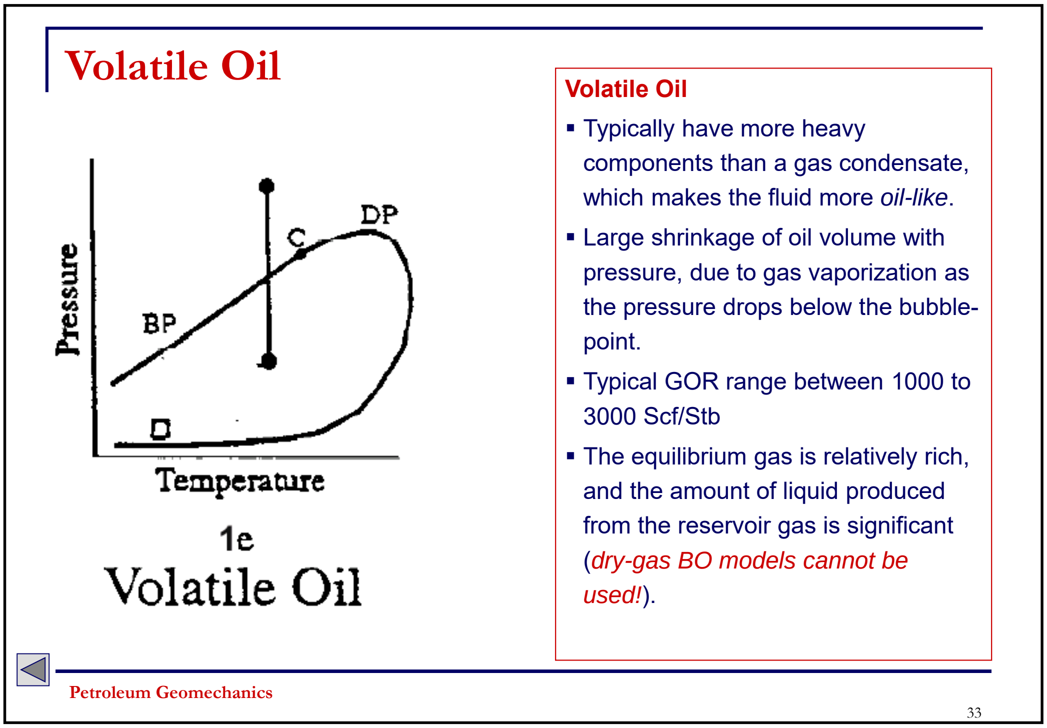
- Mainly composed of light HC components (C_1, C_2, C_3 and C_4).
- Wet gas will not drop out condensate at reservoir conditions, only at surface conditions.
- Producing GOR typically higher than 50,000 Scf/Stb and will remain constant throughout depletion.



Gas Condensate

Gas Condensate

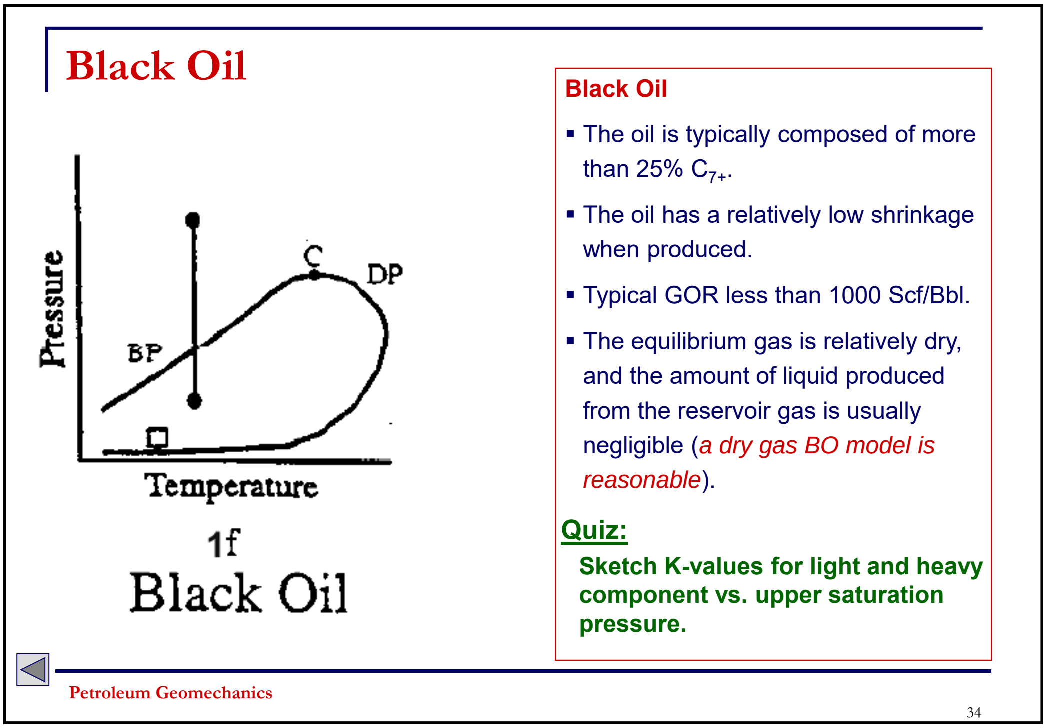
- Presence of heavier components (C_4-C_{7+}) expands the phase envelope, so that the reservoir temperature lies between the critical point and cricondentherm.
- Liquid drops out during depletion due to retrograde condensation, further condensation also occurs at surface conditions.
- Liquid dropout in the reservoir will generally lead to lower condensate recovery (immobile oil phase) and may result in poor well deliverabilities.
- Typical GOR range between 3000 to 150,000 Scf/Stb



Volatile Oil

Volatile Oil

- Typically have more heavy components than a gas condensate, which makes the fluid more *oil-like*.
- Large shrinkage of oil volume with pressure, due to gas vaporization as the pressure drops below the bubble-point.
- Typical GOR range between 1000 to 3000 Scf/Stb
- The equilibrium gas is relatively rich, and the amount of liquid produced from the reservoir gas is significant (*dry-gas BO models cannot be used!*).



Black Oil

Black Oil

- The oil is typically composed of more than 25% C_{7+}.
- The oil has a relatively low shrinkage when produced.
- Typical GOR less than 1000 Scf/Bbl.
- The equilibrium gas is relatively dry, and the amount of liquid produced from the reservoir gas is usually negligible (*a dry gas BO model is reasonable*).

Quiz:

Sketch K-values for light and heavy component vs. upper saturation pressure.

Composition of Several Reservoir Fluids

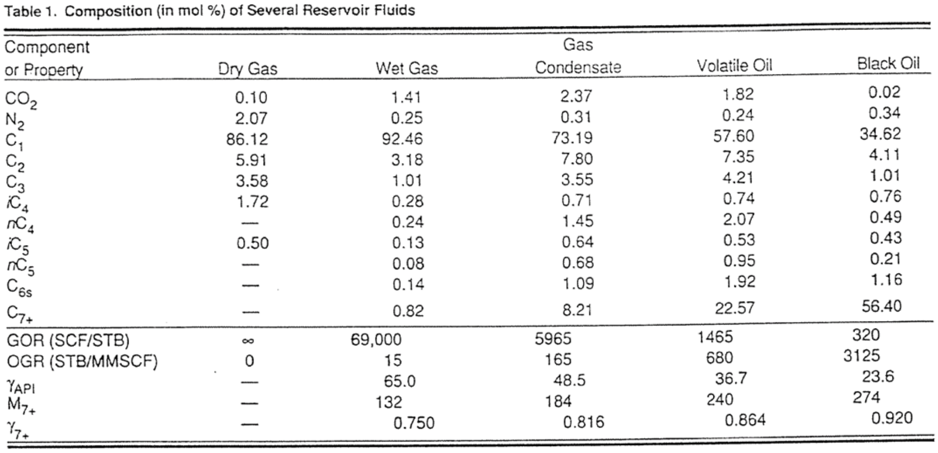


Table 1. Composition (in mol %) of Several Reservoir Fluids

Component or Property	Dry Gas	Wet Gas	Gas Condensate	Volatile Oil	Black Oil
CO_2	0.10	1.41	2.37	1.82	0.02
N_2	2.07	0.25	0.31	0.24	0.34
C_1	86.12	92.46	73.19	57.60	34.62
C_2	5.91	3.18	7.80	7.35	4.11
C_3	3.58	1.01	3.55	4.21	1.01
iC_4	1.72	0.28	0.71	0.74	0.76
nC_4	—	0.24	1.45	2.07	0.49
iC_5	0.50	0.13	0.64	0.53	0.43
nC_5	—	0.08	0.68	0.95	0.21
C_{6s}	—	0.14	1.09	1.92	1.16
C_{7+}	—	0.82	8.21	22.57	56.40
GOR (SCF/STB)	∞	69,000	5965	1465	320
OGR (STB/MMSCF)	0	15	165	680	3125
γ_{API}	—	65.0	48.5	36.7	23.6
M_{7+}	—	132	184	240	274
γ_{7+}	—	0.750	0.816	0.864	0.920

Gas PVT Properties

Gas Properties:

- Compressibility factor, Z.
- Density, ρ_g.
- Specific gravity, γ_g.
- Gas volume factor, B_g.
- Solution oil-gas ratio, r_v.
- Viscosity, μ_g.

The Ideal Gas Law

$$pV = nRT$$

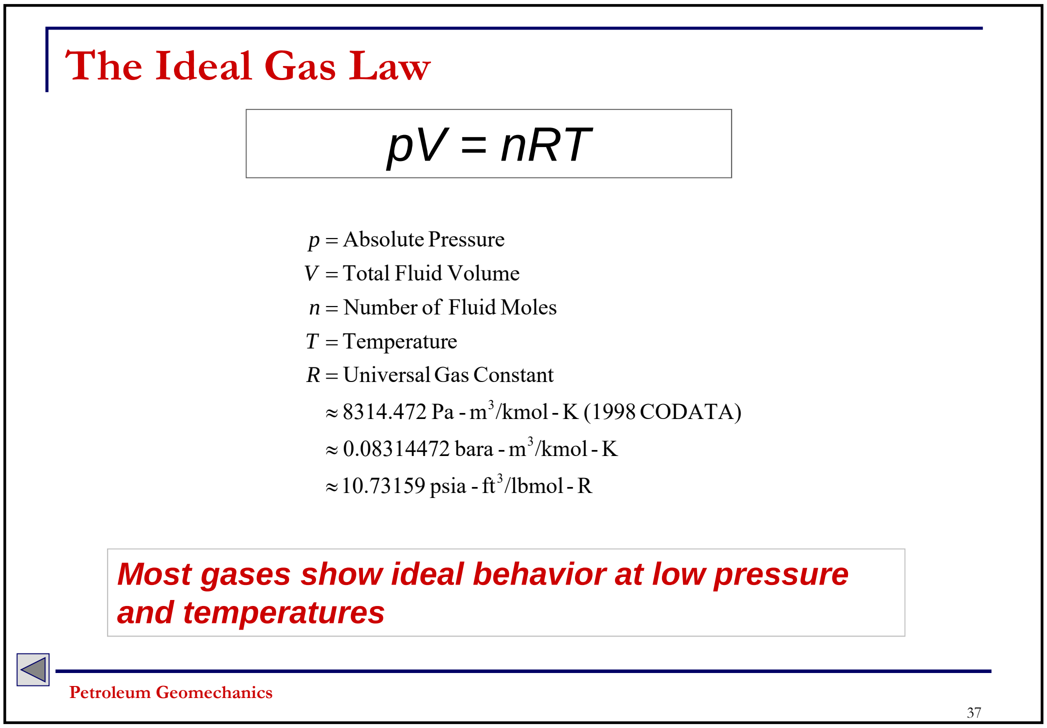
Ideal gases:

- *No interacting forces between the molecules.*
- *The volume of the molecules are negligible compared to the total gas volume.*

The deviation from ideal behavior is expressed by the Z-factor.

The Real Gas Law

$$pV = ZnRT$$

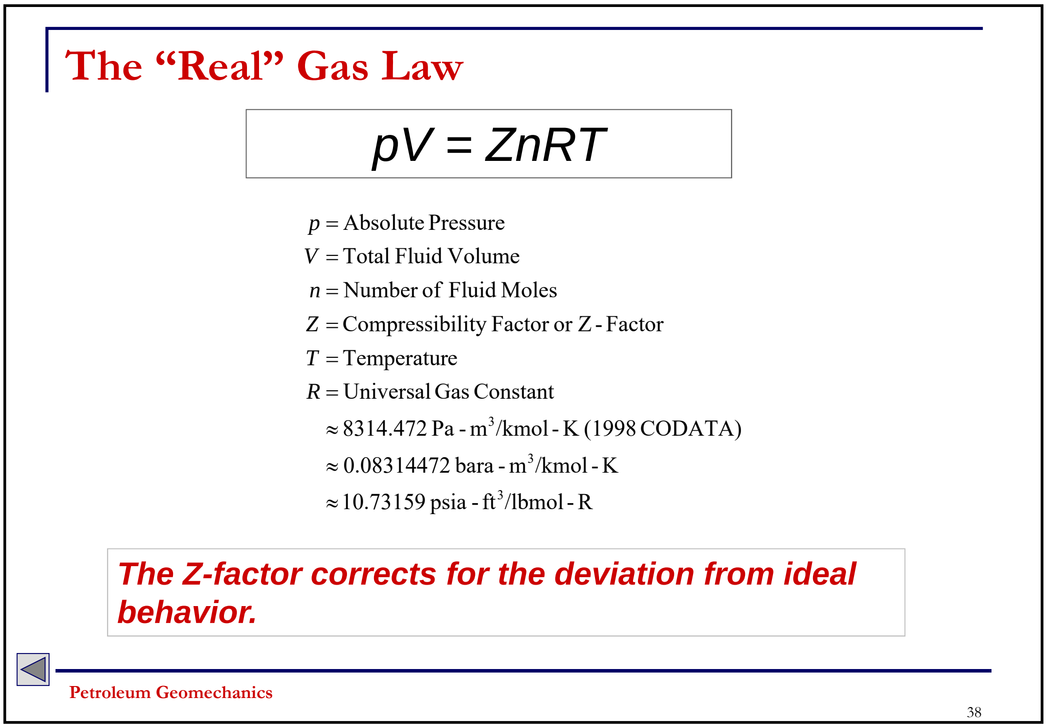


The Ideal Gas Law

$$pV = nRT$$

p = Absolute Pressure
V = Total Fluid Volume
n = Number of Fluid Moles
T = Temperature
R = Universal Gas Constant
≈ 8314.472 Pa - m^3/kmol - K (1998 CODATA)
≈ 0.08314472 bara - m^3/kmol - K
≈ 10.73159 psia - ft^3/lbmol - R

Most gases show ideal behavior at low pressure and temperatures



The "Real" Gas Law

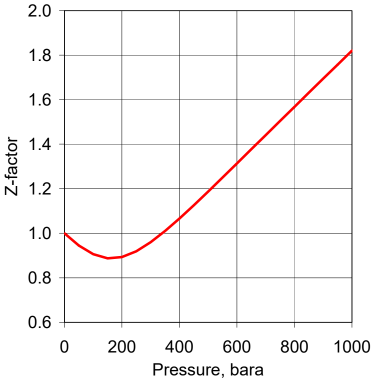
$$pV = ZnRT$$

p = Absolute Pressure
V = Total Fluid Volume
n = Number of Fluid Moles
Z = Compressibility Factor or Z - Factor
T = Temperature
R = Universal Gas Constant
≈ 8314.472 Pa - m^3/kmol - K (1998 CODATA)
≈ 0.08314472 bara - m^3/kmol - K
≈ 10.73159 psia - ft^3/lbmol - R

The Z-factor corrects for the deviation from ideal behavior.

Compressibility Factor (Z-Factor)

$$Z = \frac{Actual\,V_g}{Ideal\,V_g}$$



- The Z-factor gives accurate gas volumetric properties (B_g, ρ_g, c_g)
- The Z-factor is particularly important for estimating initial gas in place (IGIP = HCPV/B_g) and gas depletion recovery factors.
- Z-factor is a function of pressure p, temperature T, and gas composition y.
- Z-factor is usually expressed as function of pseudo-reduced pressure and temperature, Z(p_{pr},T_{pr}), where p_{pr}=p/p_{pc} and T_{pr}=T/T_{pc}. (YH Correlation)
- Pseudo-critical properties p_{pc} and T_{pc} are functions of gas composition y_i. Molar averages of the component critical properties, p_c and T_c, are normally used. (**Mixing Rules**)
- Accuracy of Z-factors from the **Standing-Katz chart** should usually be 1-3%.

Hall & Yarborough Z-factor Correlation (Based on Standing & Katz Z-factor Chart)

$$Z = \alpha p_{pr}/y, \quad \ldots\ldots\ldots\ldots \quad (3.42)$$

where $\alpha = 0.06125t\exp[-1.2(1-t)^2]$, where $t = 1/T_{pr}$.

The reduced-density parameter, y (the product of a van der Waals covolume and density), is obtained by solving

$$\begin{aligned} f(y) = 0 = &-\alpha p_{pr} + \frac{y + y^2 + y^3 - y^4}{(1-y)^3} \\ &- (14.76t - 9.76t^2 + 4.58t^3)y^2 \\ &+ (90.7t - 242.2t^2 + 42.4t^3)y^{2.18+2.82t}, \quad \ldots\ldots \quad (3.43) \end{aligned}$$

$$\begin{aligned} \text{with } \frac{df(y)}{dy} = &\frac{1 + 4y + 4y^2 - 4y^3 + y^4}{(1-y)^4} \\ &- (29.52t - 19.52t^2 + 9.16t^3)y \\ &+ (2.18 + 2.82t)(90.7t - 242.2t^2 + 42.4t^3) \\ &\times y^{1.18+2.82t}. \quad \ldots\ldots\ldots\ldots \quad (3.44) \end{aligned}$$

The derivative $\partial Z/\partial p$ used in the definition of c_g is given by

$$\left(\frac{\partial Z}{\partial p}\right)_T = \frac{\alpha}{p_{pc}}\left[\frac{1}{y} - \frac{\alpha p_{pr}/y^2}{df(y)/dy}\right]. \quad \ldots\ldots\ldots\ldots \quad (3.45)$$

Calculation of Average Mixture Properties

Having defined amounts and properties for each individual component, we can calculate average mixture properties by a simple mixing rule:

$$\bar{\theta} = \frac{\sum_{i=1}^{N_c} \phi_i \theta_i}{\sum_{i=1}^{N_c} \phi_i}$$

Where the weight factors ϕ_i may be a combination of mole fraction (z_i), mass fraction (m_i) or volume fraction (v_i)

(1) $$p_c = \sum_{i=1}^{N_c} z_i p_{ci}$$

Same mixing rule also applies to T_c and M_w.

(2) $$\rho = \frac{\sum_{i=1}^{N_c} m_i}{\sum_{i=1}^{N_c} v_i} = \frac{\sum_{i=1}^{N_c} m_i}{\sum_{i=1}^{N_c} \frac{m_i}{\rho_i}}$$

Same mixing rule applies to γ

Example: p_c, T_c

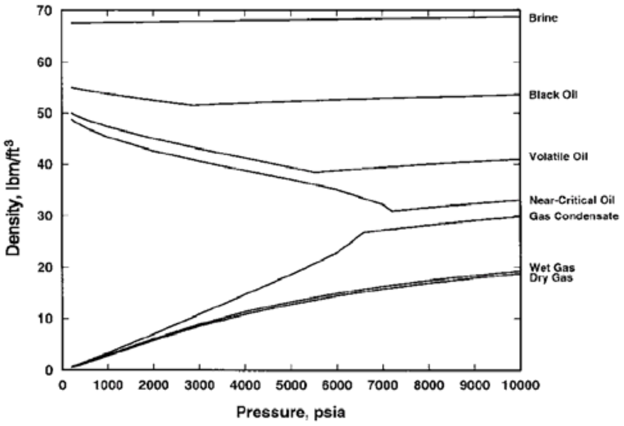
Relative Gas Density

$$\gamma_g = \frac{(\rho_g)_{sc}}{(\rho_{air})_{sc}}$$

$$\gamma_g = \frac{M_g}{M_{air}} = \frac{M_g}{28.97}$$

- **Specific gravity is the ratio of the gas density to the density of air, both at *standard conditions.***
- **Specific gravity is dimensionless number that reflects the molecular weight of the gas.**
- **The specific gravity of a gas is a function of the molar composition, and is normally calculated by a linear mixing (averaging) of the individual component molecular weights.**
- **The specific gravity can be used in Z-factor correlations.**

Gas Density



$$\rho_g = \frac{m}{V}$$

Real Gas Law:

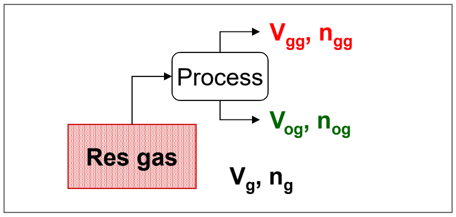
$$m = \frac{PVM}{ZRT}$$

$$\boxed{\rho_g = \frac{pM}{ZRT}}$$

Typical units:

lbm/ft³, kg/m³, g/cc

Gas Volume Factor



$$\boxed{B_g = \left(\frac{V_{g,res}}{V_{g,SC}}\right)}$$

Dry gases:

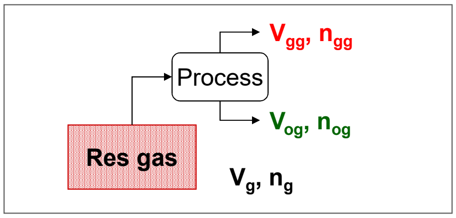
$$\boxed{B_g = \left(\frac{p_{sc}}{T_{sc}}\right)\frac{ZT}{p}}$$

Wet gases & Gas condensates:

$$\boxed{B_{gd} = \left(\frac{p_{sc}}{T_{sc}}\right)\frac{ZT}{p}\left(\frac{n_g}{n_{gg}}\right)}$$

- **Gas volume factor is defined as the ratio between gas volume at p and T to the *ideal* gas volume at standard conditions.**
- **The classical definition of B_g assumes that all the reservoir gas is produced as gas at the surface. However, for wet gases and gas condensates this is not the case, since liquid will be produced after separation.**
- **If the reservoir gas yields condensate, the “dry gas volume factor” B_{gd} is often used.**

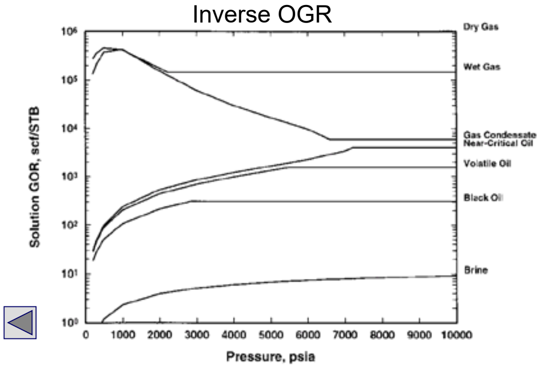
Solution Oil Gas Ratio (OGR)



Solution oil-gas ratio:

$$\boxed{r_v = \left(\frac{V_{og}}{V_{gg}}\right)}$$

- The solution oil gas ratio is defined as the volume of gas at standard conditions to the stock tank oil volume. Common units are Stb/Mscf, or Sm^3/Sm^3.
- For a wet gas reservoir, the solution OGR is more or less constant (well stream composition does not change).
- For gas condensates the solution OGR changes, due to liquid drop-out in the reservoir.


Inverse OGR

Gas Viscosity

Lee-Gonzalez gas viscosity correlation

$$\mu_g = A_1 \times 10^{-4} \exp\left(A_2 \rho_g^{A_3}\right)$$

$$\text{where } A_1 = \frac{(9.379 + 0.01607 M_g) T^{1.5}}{209.2 + 19.26 M_g + T},$$

$$A_2 = 3.448 + (986.4/T) + 0.01009 M_g,$$

$$\text{and } A_3 = 2.447 - 0.2224 A_2, \quad \ldots\ldots\ldots$$

μ_g in cp, ρ_g in g/cm^3, and T in °R

- Dynamic viscosity is a measure for the fluids “internal resistance to flow”.
- Dynamic viscosity is measured in centipoise (cP) or pascal-seconds (Pa·s)
- Gas viscosities are a function of composition, pressure and temperature.
- Gas viscosity increase with pressure. At high pressure, the gas viscosity approaches that of an liquid.
- Gas viscosities typically range between 0.01 cp for dry gases up to 0.1 cp for near critical gas condensates.
- Gas viscosities are seldom measured, but usually estimated based on correlations.

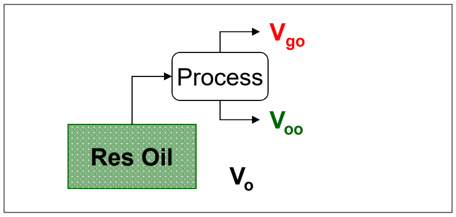
Oil PVT Properties

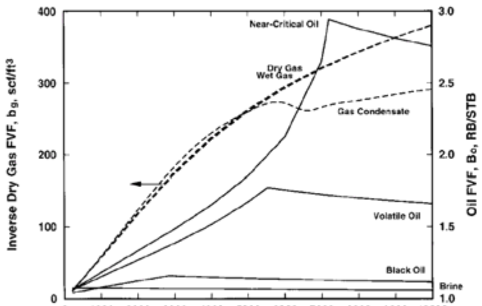
Oil Properties:

- Volume factor, B_o
- Solution gas-oil ratio, R_s
- Density, ρ_o.
- Viscosity, μ_o

- The description of volumetric properties oil properties are divided into two categories:
  - ***Saturated oil.***
  - ***Under-saturated oil.***
- The volumetric behavior at the bubble-point is highly dependent upon the amount of solution gas.

Oil Volume Factor





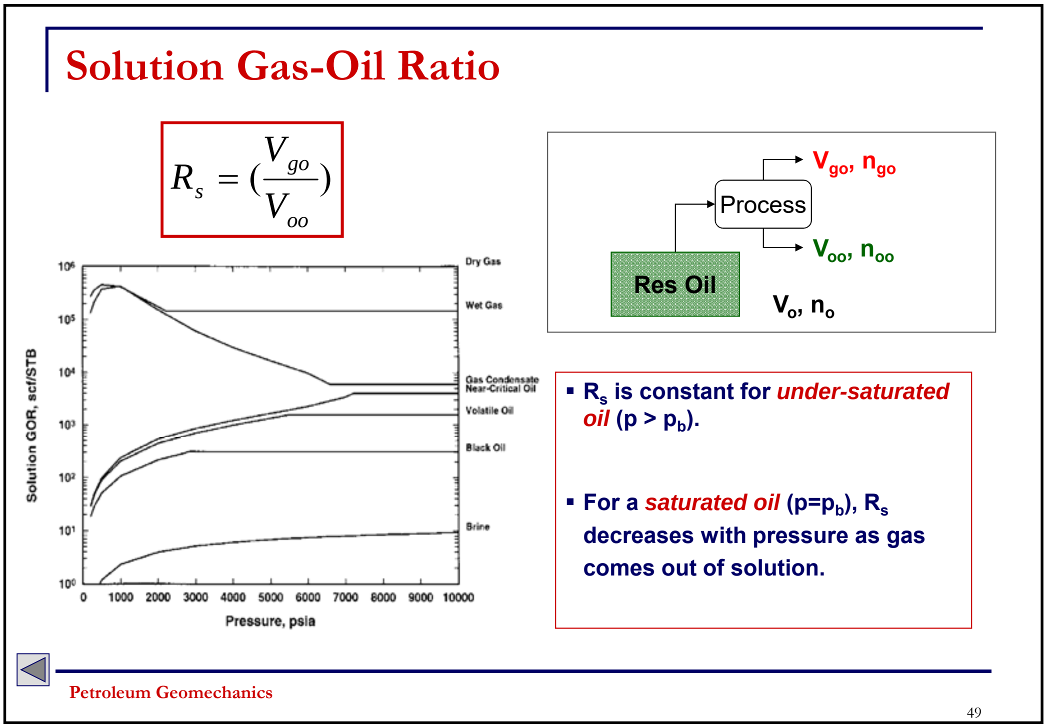
Oil Volume Factor

$$B_o = \left(\frac{V_o}{V_{oo}}\right)$$

- **For an *under-saturated* oil ($p > p_b$), B_o decreases with pressure due to expansion of the oil. The oil expansion is given by the compressibility factor, C_o:**

$$B_o = B_{ob}(1 - C_o(p - p_b))$$

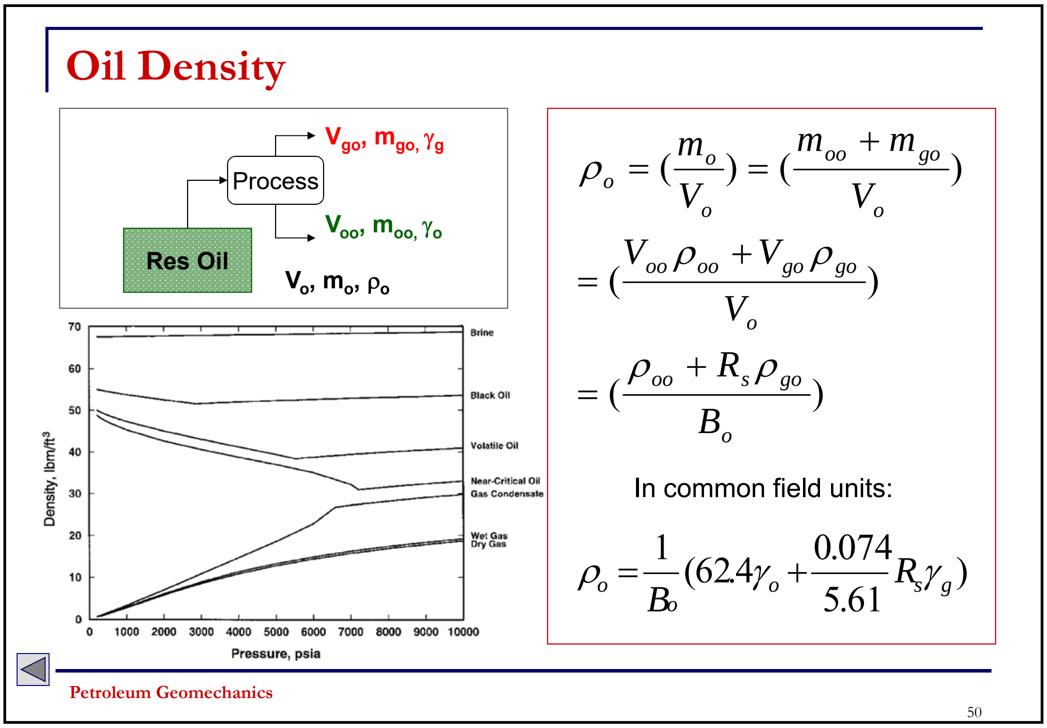
- **For a *saturated* oil ($p = p_b$), Bo decreases with pressure due to oil shrinkage as gas comes out of solution.**



Solution Gas-Oil Ratio

$$R_s = \left(\frac{V_{go}}{V_{oo}}\right)$$

- R_s is constant for *under-saturated oil* ($p > p_b$).
- For a *saturated oil* ($p=p_b$), R_s decreases with pressure as gas comes out of solution.



Oil Density

$$\rho_o = \left(\frac{m_o}{V_o}\right) = \left(\frac{m_{oo} + m_{go}}{V_o}\right)$$

$$= \left(\frac{V_{oo}\rho_{oo} + V_{go}\rho_{go}}{V_o}\right)$$

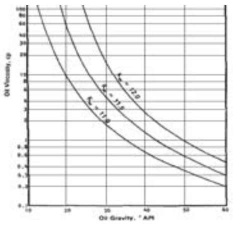
$$= \left(\frac{\rho_{oo} + R_s\rho_{go}}{B_o}\right)$$

In common field units:

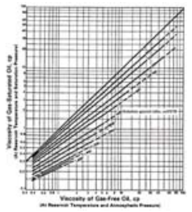
$$\rho_o = \frac{1}{B_o}\left(62.4\gamma_o + \frac{0.074}{5.61} R_s \gamma_g\right)$$

Oil Viscosity

- Typical oil viscosities range from 0.1 cp for near critical oils to > 100 cp for heavy crudes.
- Temperature, stock-tank oil density and dissolved gas amount are they key parameters determining the oil viscosity.
- Live oil viscosities are often estimated from correlations which account for the effect of dissolved gas and pressure on viscosity.
- Oil viscosity increase with increasing STO density, decreasing temperature, and decreasing solution gas amount.
- Oil viscosities are difficult to estimate – typical accuracy only about 10-20%



Dead oil viscosity chart



Live oil viscosity chart