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.

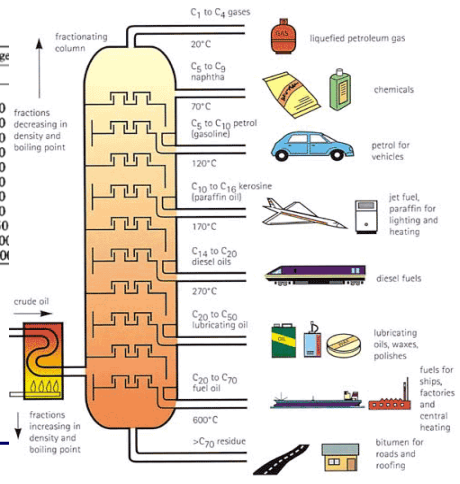
- Introduction.
- Petroleum reservoir fluids.
- Fluid phase behavior.
- Classification of reservoir fluids.
- Basic reservoir gas properties
- Basic reservoir oil properties.

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	Approximate boiling range °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



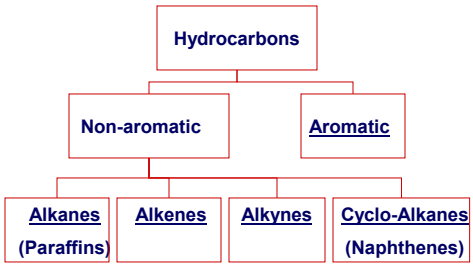
Petroleum Fluids

- 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 hydro-carbon compounds (Aromatic and Naphthenes).

Example Compositions

Hydrocarbons

$$C_nH_{2n+h}$$



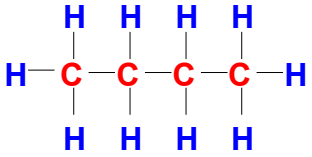
Petroleum Fluids – Example Compositions

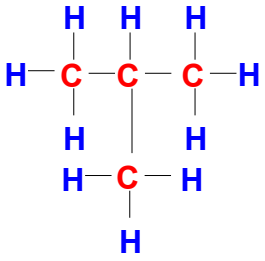
Component	Dry Gas	Wet Gas	Gas Condensate	Near-Critical Oil	Volatile Oil	Black Oil
CO_2	0.10	1.41	2.37	1.30	0.93	0.02
N_2	2.07	0.25	0.31	0.56	0.21	0.34
C_1	86.12	92.46	73.19	69.44	58.77	34.62
C_2	5.91	3.18	7.80	7.88	7.57	4.11
C_3	3.58	1.01	3.55	4.26	4.09	1.01
i-C_4	1.72	0.28	0.71	0.89	0.91	0.76
n-C_4		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}, ft³/scf or bbl/STB		0.0051	0.0039	2.78	1.73	1.16
ρ_{sat}, lbm/ft³		9.61	26.7	30.7	38.2	51.4

Alkanes (Paraffins)

Structure Formula

C_nH_{2n+2}





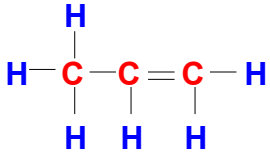
$n\text{-}C_4H_{10}$: normal-butane

$i\text{-}C_4H_{10}$: iso-butane

Alkenes (Olefins)

Structure Formula

C_nH_{2n}



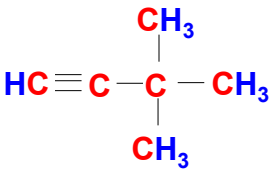
C_3H_6 : propene

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

Alkynes

Structure Formula

C_nH_{2n-2}



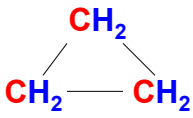
C_6H_{10} : Heksyne

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

Cyclo-alkanes (Naphthenes)

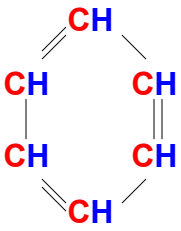
Structure Formula

C_nH_{2n}

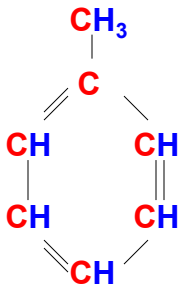


C_3H_6 : cyclo-butane

Aromatics



Benzene



Tuolene

Petroleum Geomechanics

11

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.**

Petroleum Geomechanics

12

Gibbs Phase Rule

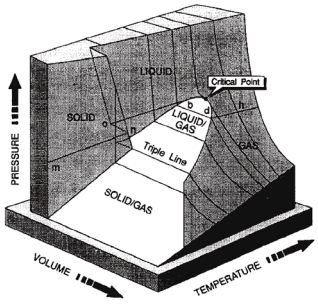
$$F = n - P + 2$$

- **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

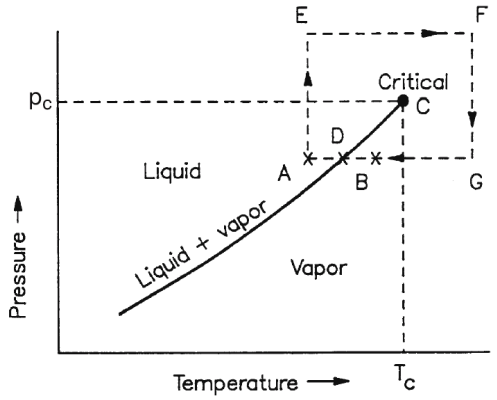
$$F = 1 - P + 2$$



- 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*** temperature 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

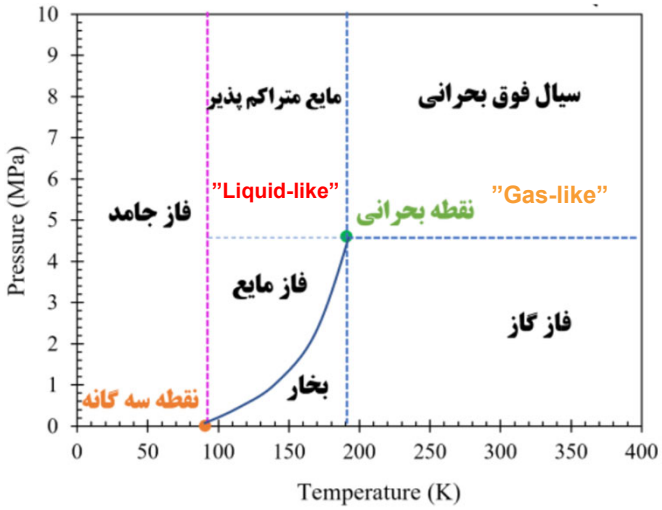


- Along the vapor-pressure curve, the two-phases are in thermodynamic equilibrium.
- The vapor-pressure curve ends at the critical point.
- At the critical point the two phases are indistinguishable.
- Liquid and vapor cannot coexist at temperatures above the critical temperature, or for pressures above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

Quiz:

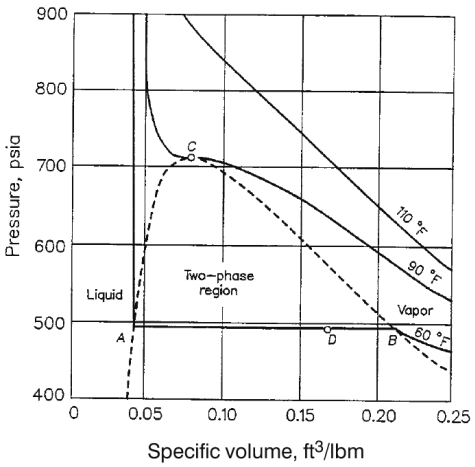
How to go from a liquid to a vapor at nearly the same conditions, without any abrupt phase change?

Single-Component Phase Transfer



دیاگرام فازی متان

Single-Component Pressure-Volume Curve



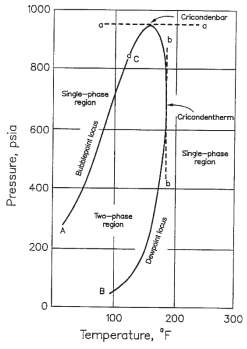
- In a single-component system, the transition from vapor to liquid takes place at a constant pressure.

Quiz:

Vapor Liquid	Vapor Liquid
V = V1 T = T1 P = P1 $\rho_o = \rho 1$	V < V1 T = T1 P = ? ρ_o = ?

Two-Component Phase Behavior

$$F = 2 - P + 2$$



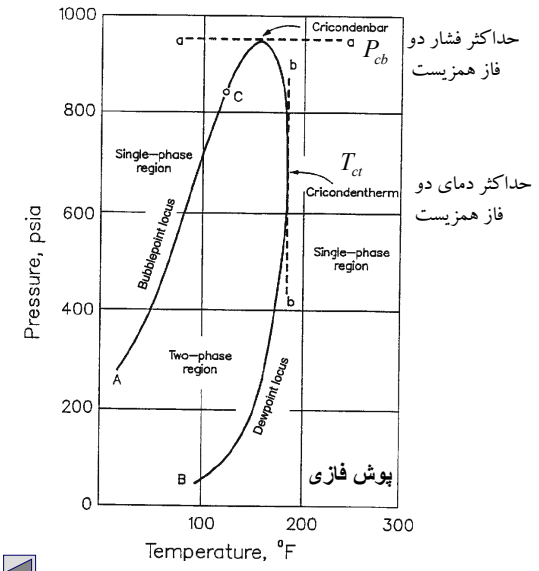
- p-T diagram
- p-V diagram
- p-x diagram

Equilibrium K-Values

$$K_i \equiv y_i / x_i$$

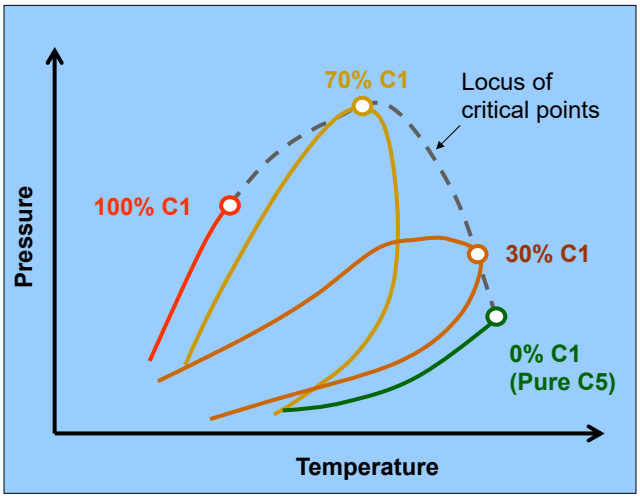
- For a single-phase, two-component system, **F = 3**, and the phase behavior is completely determined by pressure, temperature and composition.
- For a two-phase, two-component system, **F = 2** and in addition to composition, either pressure ***or*** temperature must to be specified to determine the 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



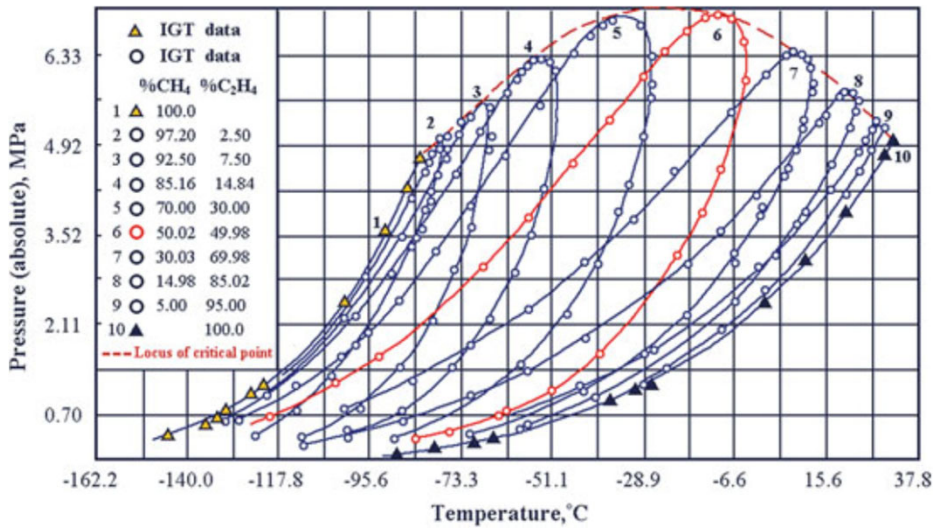
- In going from one to two (or more) components, the P-T Diagram (at constant composition) goes from a Vapor Pressure Curve to a Two-Phase Envelope.
- Two-phase envelopes always consist of Bubble Point and Dew Point surfaces, which meet at Critical Points. At the critical point, the phases are indistinguishable.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

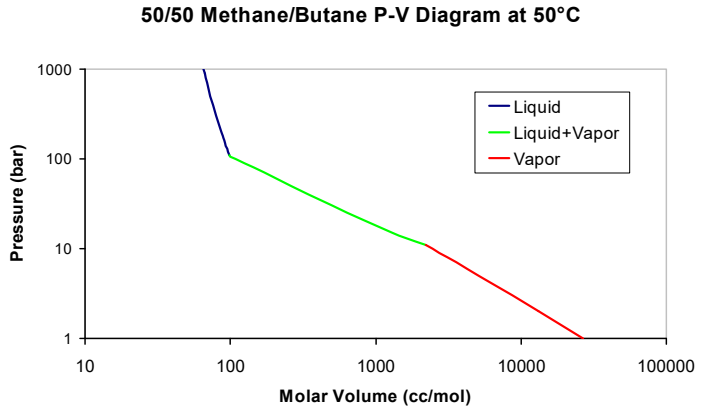


- The shape of the phase diagram is dependent on the fluid composition.
- The critical temperature of the mixture is always between the critical temperatures of the pure components
- The critical pressure of the mixture is usually higher than the critical pressure of the pure components.
- In general,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

Phase Diagram of mixtures of methane and ethane

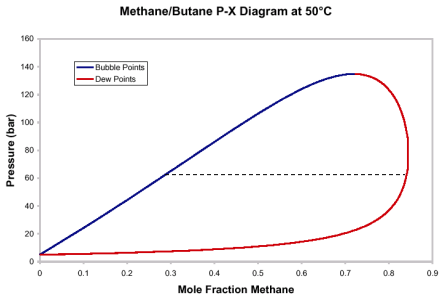


Two-Component p-V Diagram



- 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



- 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 bar?

Equilibrium K-Values

$$K_i \equiv y_i / x_i$$

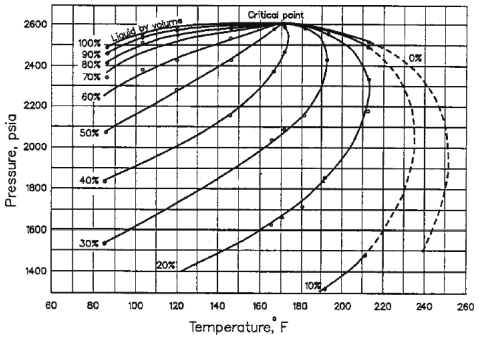
- y_i = mole fraction of component *i* in the vapor phase
- x_i = mole fraction of component *i* in the liquid phase

- 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

$$F = n_c - P + 2$$



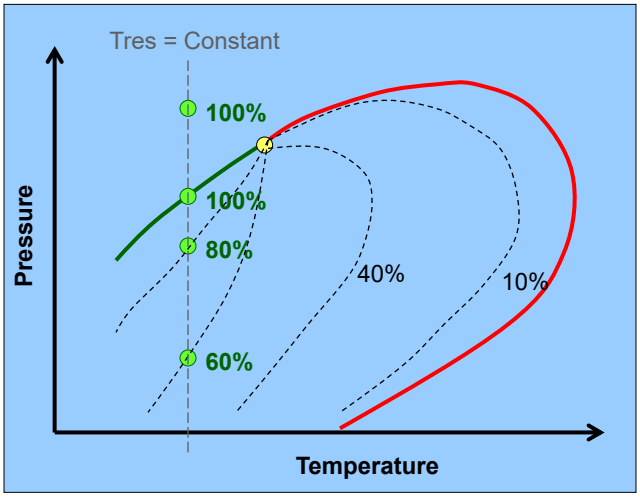
PT-diagram for gas condensate fluid (after Katz et. al) showing lines of constant liquid percentage (quality lines).

- 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:

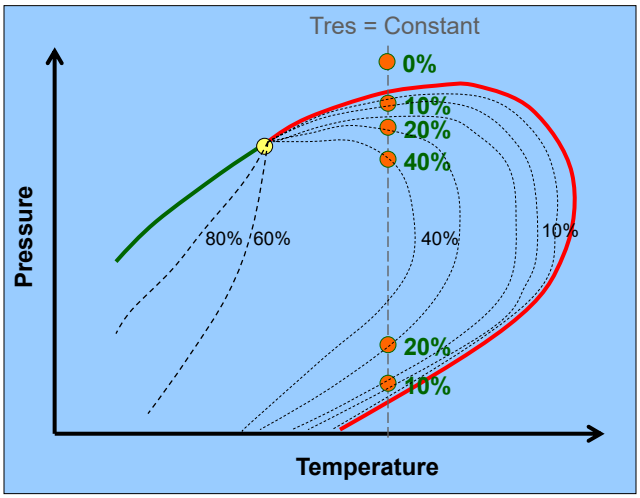
- The volume amount of each phase inside the two-phase region is given by the pressure and temperature.
- Lines of constant liquid ratio are called iso-volume or quality lines.
- Liquid can be formed by an isothermal decrease in pressure – this is called **retrograde condensation.**

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

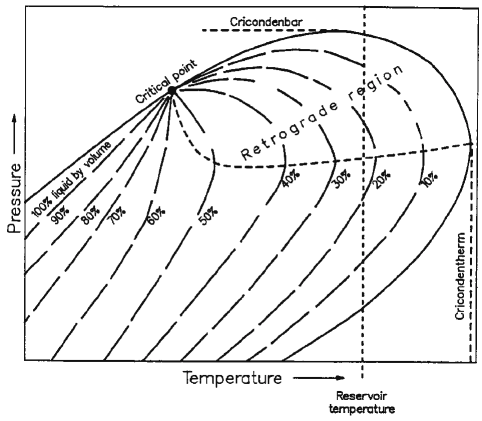
Retrograde Condensation



- **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



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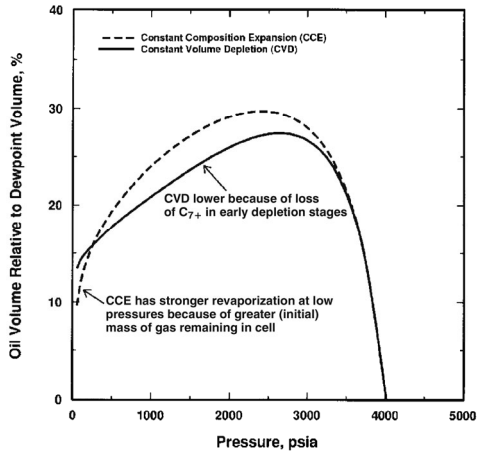
Retrograde Liquid Dropout

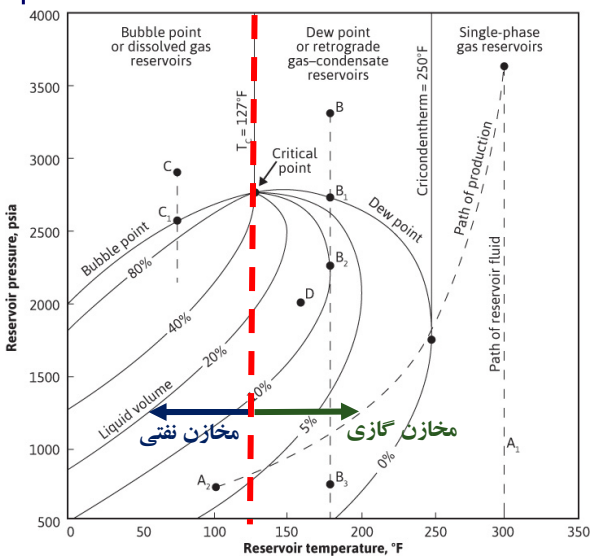
Constant Composition vs. Constant Volume



Petroleum Geomechanics

29

Classification of Reservoir Fluid Systems



نوع مخزن

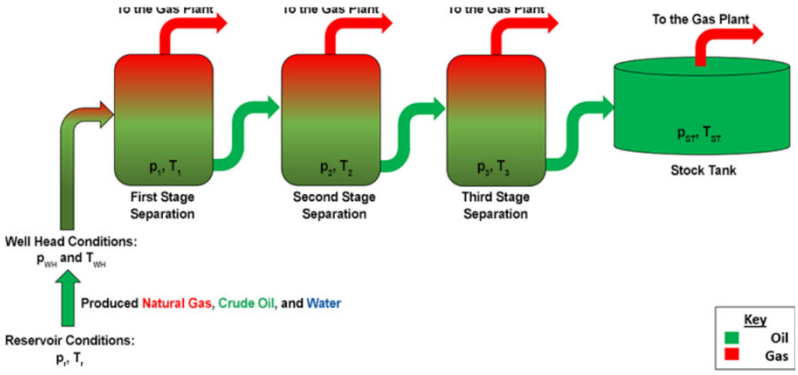
مخازن نفتی :

اگر دمای مخزن کمتر از دمای بحرانی سیال مخزن Tc باشد.

مخازن گازی:

اگر دمای مخزن بیشتر از دمای بحرانی سیال هیدروکربنی مخزن باشد.

دما و فشار در قسمتهای مختلف تولید



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واحدهای حجم

Volume Units:		
4#P P VWE	@#1/333#P VWE#ru#hVWE	@#1/333/333#VWE
4#P P eeo	@#1/333#P eeoru#eeo	@#1/333/333#eeo
4#P P VFI	@#1/333#P VFI#ru#runVFI	@#1/333/333#VFI
4#P P #w^3	@#1/333#P #w^3 ru#h#w^3	@#1/333/333#w^3
4#P P VWE2gd|	@#1/333#P VWE2gd|#w^3 ru#hVWE2gd|#	@#1/333/333#VWE2gd|
4#P P VFI2gd|	@#1/333#P VFI2gd|#ru#hVFI2gd|#	@#1/333/333#VFI2gd|

bbl: Barrel
SCF: Standard Cubic Feet
STB: Stock Tank Barrel

1 bbl = 42 gal (U.S.)= 159 litres

Classification of Reservoir Fluid Systems

Classifications:

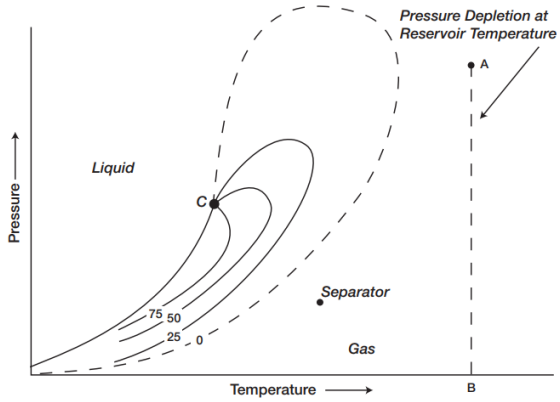
1. Dry Gas.
2. Wet Gas.
3. Gas Condensate.
4. Volatile Oil.
5. Black Oil.

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



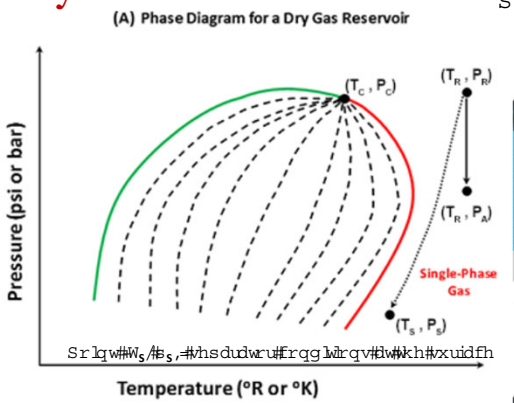
Phase diagram for a dry gas.
(*After Clark, N.J.* Elements of Petroleum Reservoirs, *SPE, 1969.*)

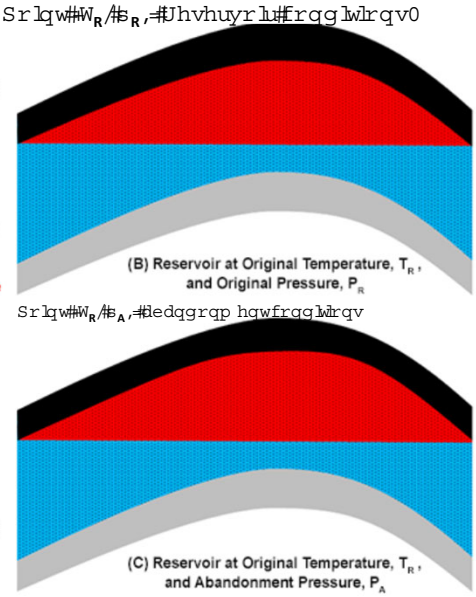
Dry Gas

- Mainly composed of C_1 in addition to non-HC components such as N_2 , CO_2 and water
- The gas remains single-phase from the reservoir to surface conditions (no condensate drop-out).
- system having a gas-oil ratio greater than 100,000 scf/STB is considered to be a dry gas

scf/STB: standard cubic feet per Stock Tank Barrel

Dry Gas



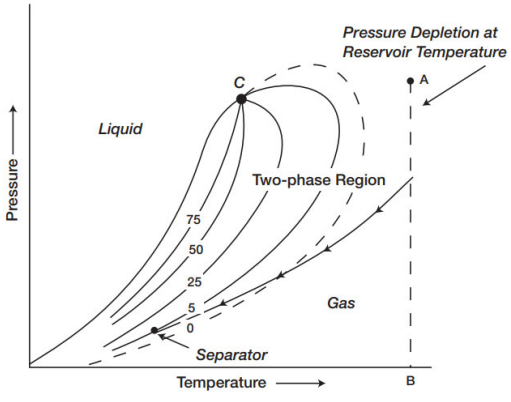


Impermeable Rock
Gas Bearing Rock
Oil Bearing Rock
Water Bearing Rock
Under Burden

Petroleum Geomechanics

35

Wet Gas



Phase diagram for a wet gas.
(*After Clark, N.J.* Elements of Petroleum Reservoirs, *SPE, 1969.*)

Wet Gas

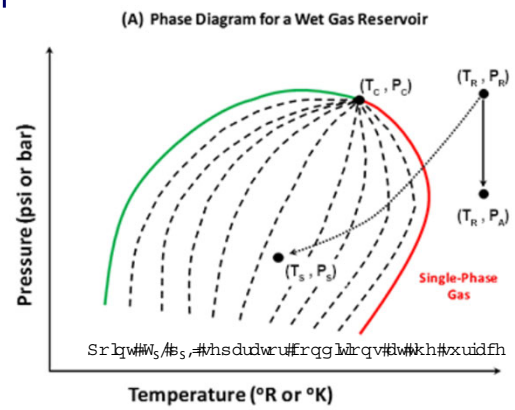
- Mainly composed of light HC components (C_1, C_2, C_3 and C_4).
- Wet gas will not drop out condensate at reservoir conditions, only at surface conditions.
- Producing GOR typically higher than 50,000 Scf/Stb and will remain constant throughout depletion.

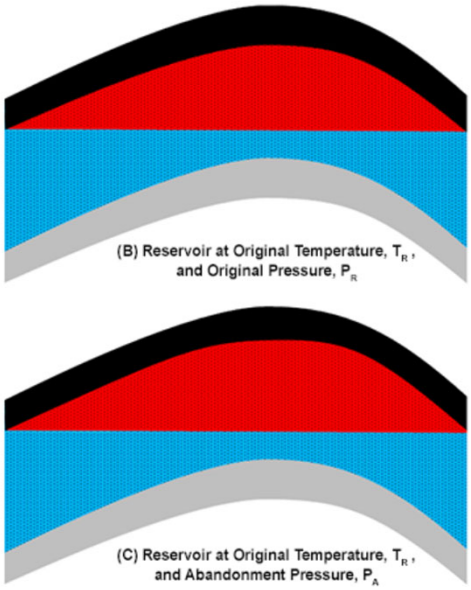
Petroleum Geomechanics

GOR : Gas-Oil Ratio

36

مخزن گاز مرطوب





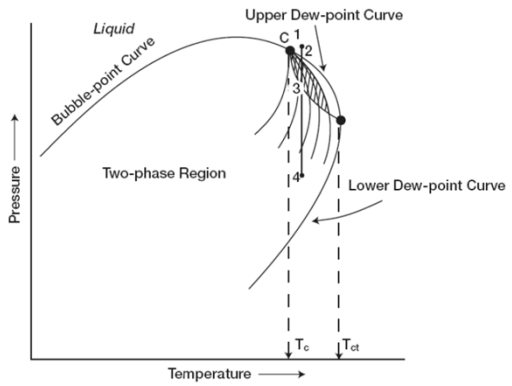
Impermeable Rock
Gas Bearing Rock
Oil Bearing Rock
Water Bearing Rock
Under Burden

Z hw#Jdv#
Uhvhuyrluv

Petroleum Geomechanics

37

Gas Condensate



A typical p-T diagram for 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 drop out 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

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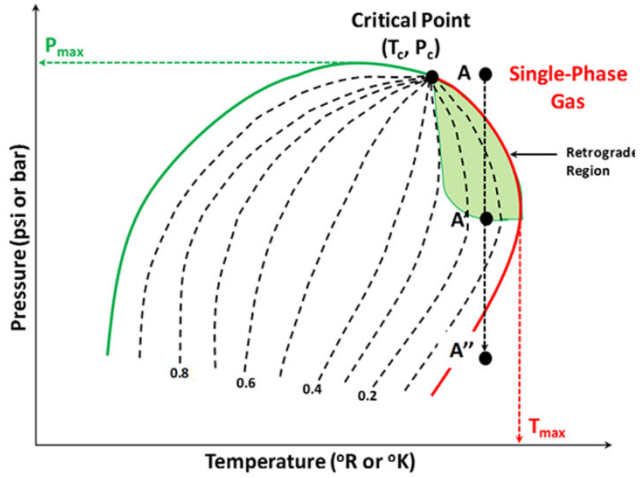
38

مخزن میعانات گازي

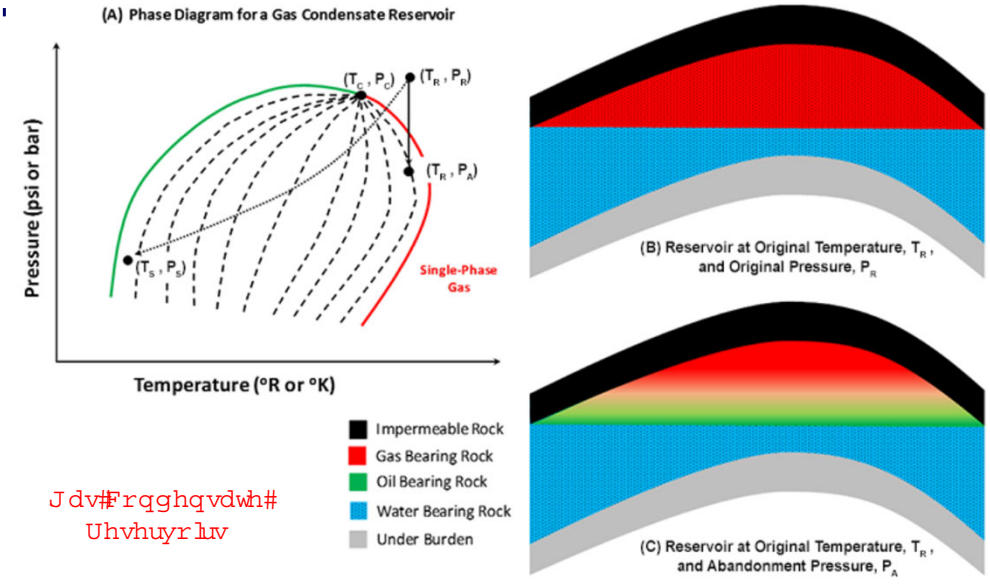


این نوع مخازن ابتدا در حالت گازی است و با استخراج و کاهش فشار مخزن، مایع در مخزن ایجاد می شود.
در هنگام به سطح آمدن نیز ایجاد مایع خواهیم داشت.

Petroleum Geomechanics

39

مخزن میعانات گازي



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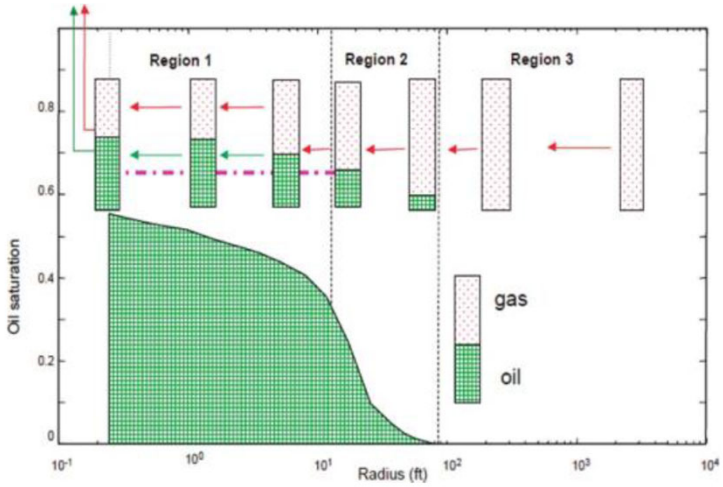
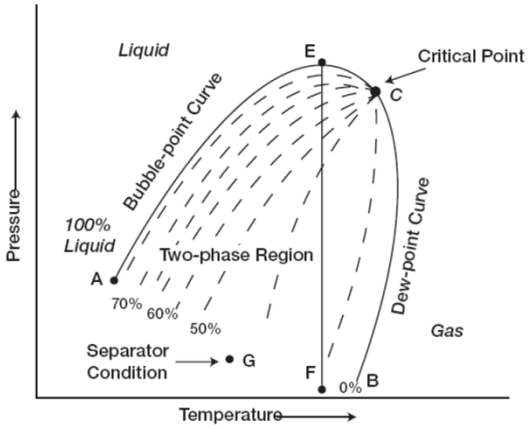
40

رفتار مخزن گازي در اطراف چاه



سه ناحیه ی رفتار چگالیده و جریان گاز در یک نمونه مخزن چگالش گازی (فواگ ۱۹۹۵)

Volatile Oil

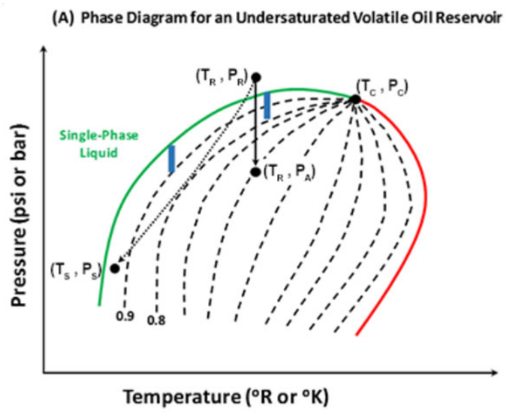


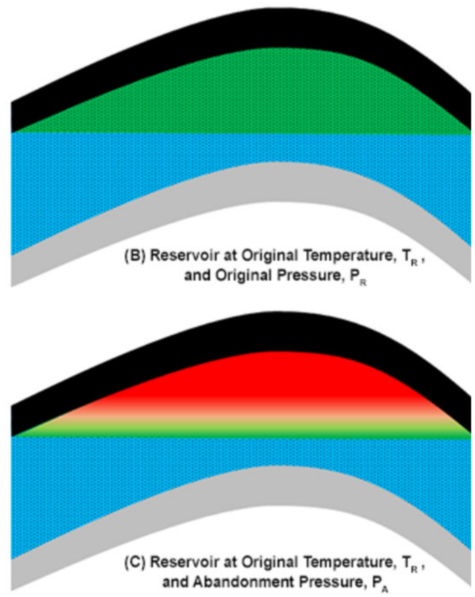
p-T diagram for a volatile oil (High-shrinkage).

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!*).

Volatile Oil

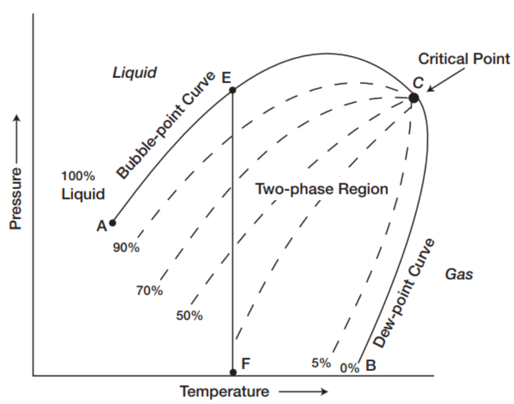




uhvhuyrlu#zlwk#dq#ruljlqdo# whp shudwxuh#uhodwlyho|# forvh#wr#wkh#fulwlfdo#srlqw

Undersaturated Volatile Oil (High Shrinkage Oil) Reservoirs

Black Oil



A typical p-T diagram for an ordinary black oil.

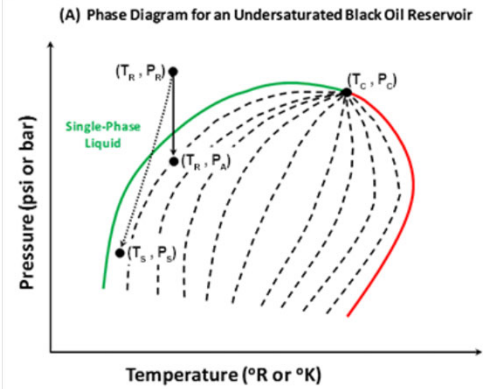
Black Oil

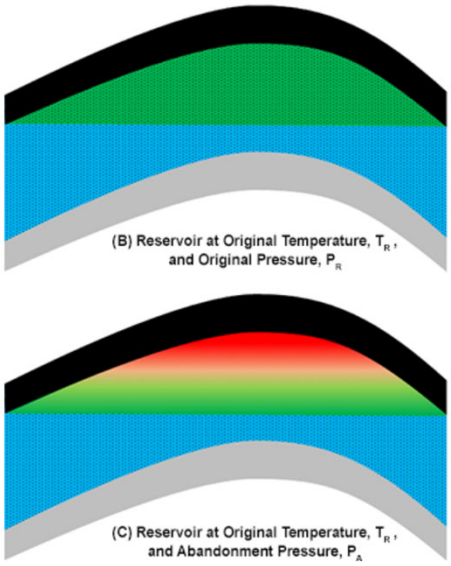
- The oil is typically composed of more than 25% C_{7+}.
- The oil has a relatively low shrinkage when produced.
- Typical GOR less than 1000 Scf/Bbl.
- The equilibrium gas is relatively dry, and the amount of liquid produced from the reservoir gas is usually negligible (*a dry gas BO model is reasonable*).

Quiz:

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

Black Oil





vhsdudwru#frqglwlrqv#dw#wkh#
vxuidfh#DSrlqw#W$/#E$,

Impermeable Rock
Gas Bearing Rock
Oil Bearing Rock
Water Bearing Rock
Under Burden

($p > p_b$)

Xqghuvdwxudwhg#Eodfn#R lc#
+Orz #Vkulqndjh,#Uhvhuyrluv

Black Oil

(A) Phase Diagram for a Saturated Black Oil Reservoir

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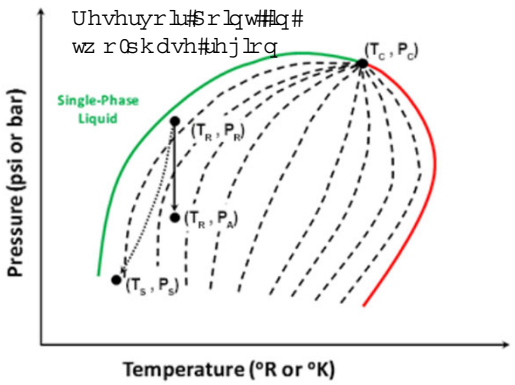
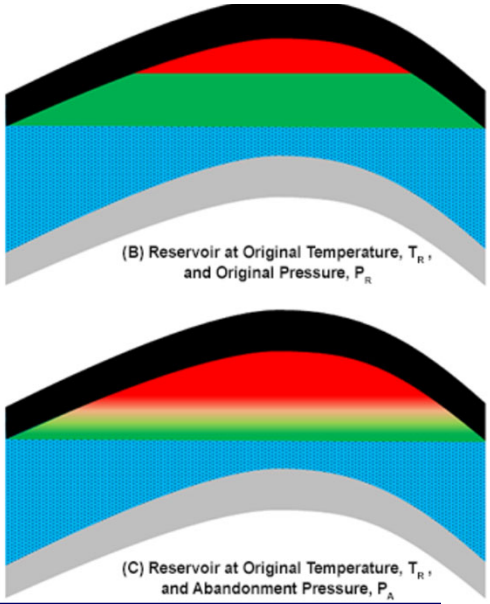
wz rOskdvh#hjlrq





Impermeable Rock
Gas Bearing Rock
Oil Bearing Rock
Water Bearing Rock
Under Burden

($p < p_b$)

Vdwxudwhg#Eodfn#R lc########
+Orz #Vkulqndjh,#Uhvhuyrluv

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

MMSCF: million standard cubic feet

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

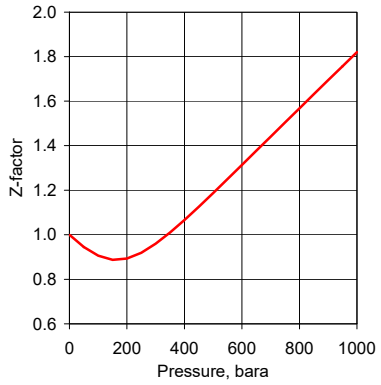
$$pV = ZnRT$$

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.
- Accuracy of Z-factors from the **Standing-Katz chart** (YH Correlation) should usually be 1-3%.

bara (Absolute Pressure), barg (Gauge Pressure)

Z-factor Correlation

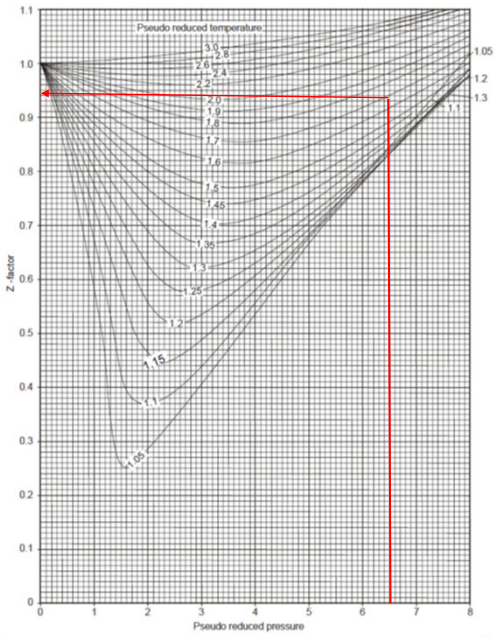
(Standing & Katz Z-factor Chart)

- Z-factor is usually expressed as function of pseudo-reduced pressure and temperature, $Z(p_{pr}, T_{pr})$

$$p_{pr} = \frac{p}{p_{pc}} \qquad p_{pc} = \sum_{i=1} y_i p_{ci}$$

$$T_{pr} = \frac{T}{T_{pc}} \qquad T_{pc} = \sum_{i=1} y_i T_{ci}$$

- 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**)



Physical properties of gases

- Physical properties of hydrocarbon gases

Gases	Molecular formula	Molecular weight	Boiling point (0.1 MPa) (°C)	Critical pressure, p_{ci} (MPa)	Critical temperature, T_{ci} (K)	Acentric factor
Methane	CH_4	16.043	−161.50	4.6408	190.67	0.0115
Ethane	C_2H_6	30.070	−88.61	4.8835	303.50	0.098
Propane	C_3H_8	44.097	−42.06	4.2568	370.00	0.1454
Isobutane	iC_4H_8	58.124	−11.72	3.6480	408.11	0.1756
Normalbutane	nC_4H_8	58.124	−0.50	3.7928	425.39	0.1928
Isobutane	iC_5H_{12}	72.151	27.83	3.3336	460.89	0.2273
Normalpentane	nC_5H_{12}	72.151	36.06	3.3770	470.11	0.2510

- Physical properties of nonhydrocarbon gases

Gases	Molecular formula	Molecular weight	Boiling point (0.1 MPa) (°C)	Critical pressure, p_{ci} (MPa)	Critical temperature, T_{ci} (K)	Acentric factor, ω
Carbon dioxide	CO_2	44.010	−78.51	7.3787	304.17	0.2250
Helium	He	4.003	−268.93	0.2289	5.278	
Hydrogen	H_2	2.016	−252.87	1.3031	33.22	−0.2234
Hydrogensulfide	H_2S	34.076	−60.31	9.0080	373.56	0.0949
Nitrogen	N_2	28.013	−195.80	3.3936	126.11	0.0355
Oxygen	O_2	31.999	−182.96	5.0807	154.78	0.0196
Aqueous vapor	H_2O	18.015	100	22.1286	647.33	0.3210

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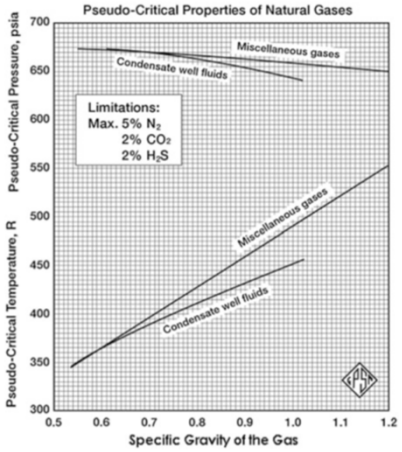
53

Z-factor Correlation

In cases where the composition of a natural gas is not available, the pseudocritical properties, i.e., p_{pc} and T_{pc}, can be estimated from the specific gravity of the gas.



According to van der Waals, (theorem of corresponding states) all fluids, when compared at the same reduced temperature and reduced pressure, have approximately the same compressibility factor.

°R = °F + 459.67

(°F) Fahrenheit scale
(°R) Rankine scale

0 K (−273.15 °C; −459.67 °F)

1 K = 9/5 °R

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54

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

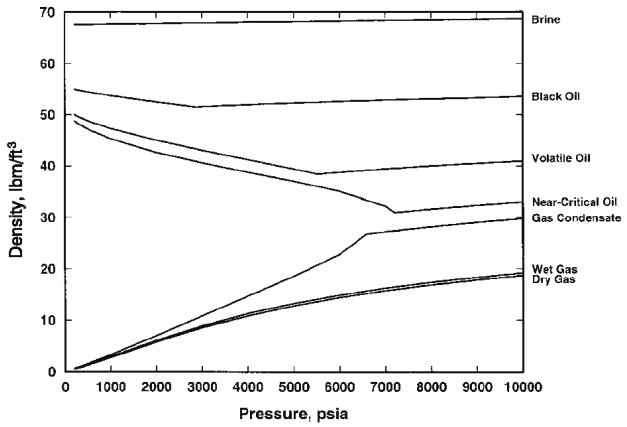
Relative Gas Density

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

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

- 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:

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

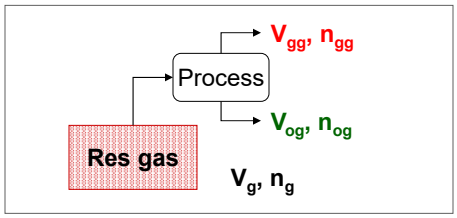
$$\rho_g = \frac{pM}{ZRT}$$

Typical units:

lbm/ft³, kg/m³, g/cc

Gas (Formation) Volume Factor

ضریب حجمی گاز(سازند)



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

Dry gases:

$$B_g = \left(\frac{p_{sc}}{T_{sc}}\right)\frac{ZT}{p}$$ or $$B_g = \frac{Z(273+t)}{2930p}$$

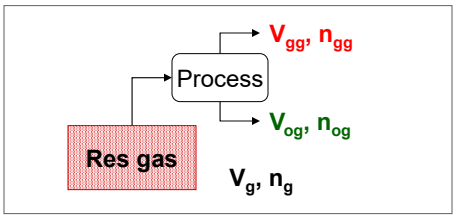
p: MPa

Wet gases & Gas condensates:

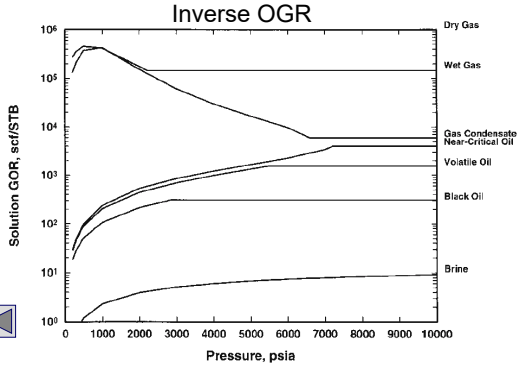
$$B_{gd} = \left(\frac{p_{sc}}{T_{sc}}\right)\frac{ZT}{p}\left(\frac{n_g}{n_{gg}}\right)$$

- **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)



Inverse OGR



Solution oil-gas ratio:

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

- 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.

59

Gas Viscosity

Lee-Gonzalez gas viscosity correlation

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

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

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

and $A_3 = 2.447 - 0.2224 A_2$, ...

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.

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60

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.

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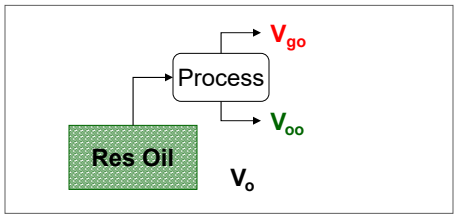
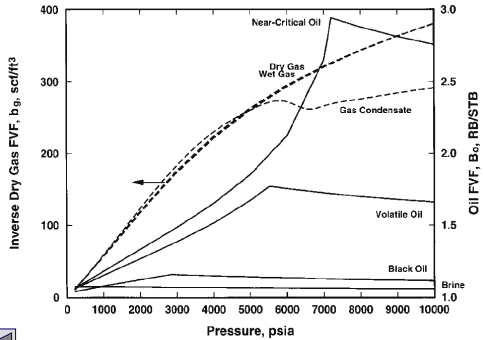
61

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 increases with pressure due to oil shrinkage as gas comes out of solution.

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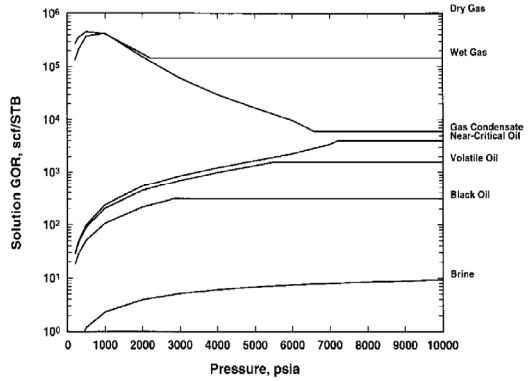
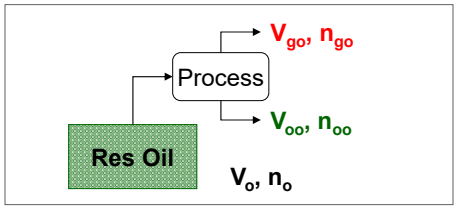
62

Solution Gas-Oil Ratio

قابلیت انحلال

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



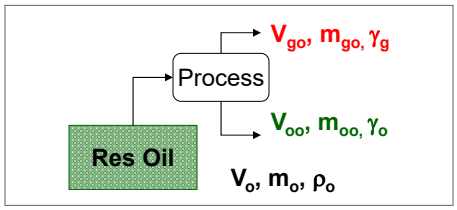


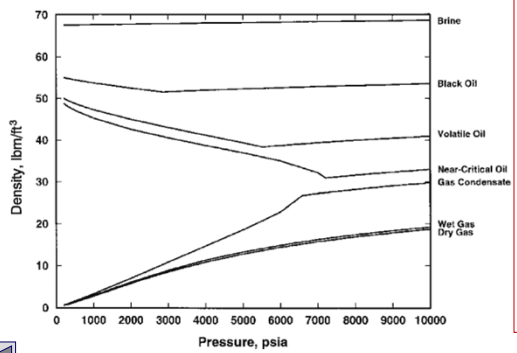
- R_s is constant for *under-saturated oil* ($p > p_b$).
- For a *saturated oil* ($p=p_b$), R_s decreases with pressure as gas comes out of solution.

Petroleum Geomechanics

63

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:

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

Petroleum Geomechanics

64

Oil Density in stock tank

The density of oil at standard condition (stock tank oil) is evaluated by API gravity.

$$API = \frac{141.5}{\gamma_o} - 131.5$$

by American Petroleum Institute

$API = \frac{141.5}{1} - 131.5 = 10$ For water $\gamma = 1$

$API = \frac{141.5}{0.9} - 131.5 = 25$ For heavy oil $\gamma = 0.9$

$API = \frac{141.5}{0.8} - 131.5 = 45$ For light oil $\gamma = 0.8$

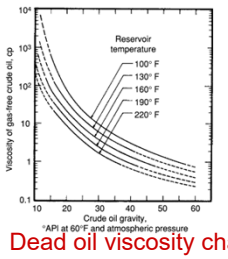
Because of gas content, density of oil is pressure dependent.

$$\gamma_o = \frac{\rho_{o,st}}{\rho_w}$$

$\rho_{o,st}$ = density of stock tank oil
ρ_w = density of freshwater

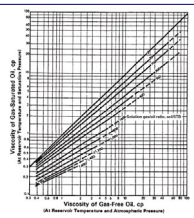
Oil Viscosity

- 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

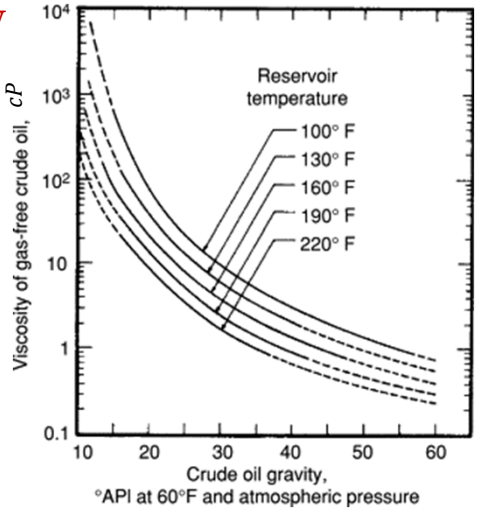
The viscosity of crude oil at atmospheric pressure (no gas in solution) and system temperature



Live oil viscosity chart

the viscosity of the oil before removal of solution gas

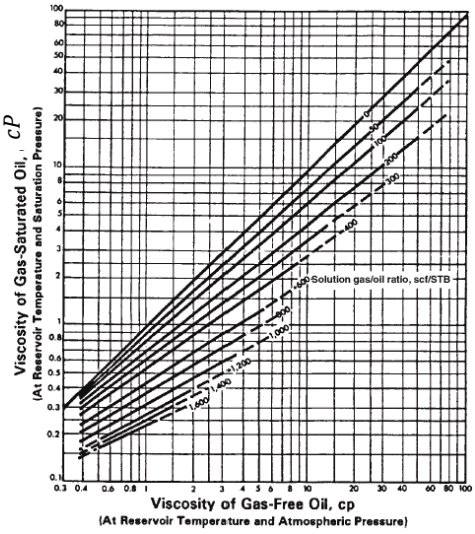
Oil Viscosity



The viscosity of crude oil at atmospheric pressure (no gas in solution) and system temperature

Dead oil viscosity chart

Oil Viscosity



Live oil viscosity chart

the viscosity of the oil before removal of solution gas

Calculation of Hydrocarbon Properties

physical properties of Hydrocarbon:

$$\theta = a_1 + a_2 n + a_3 n^2 + a_4 n^3 + (a_5/n)$$

where
q = any physical property
n = number of carbon atoms, i.e., 6. 7. . . . ., 45
a1–a5 = coefficients of

θ	a_1	a_2	a_3	a_4	a_5
M	–131.11375	24.96156	–0.34079022	2.4941184×10^{-3}	468.32575
T_c, °R	915.53747	41.421337	–0.7586859	5.8675351×10^{-3}	-1.3028779×10^{3}
P_c, psia	275.56275	–12.522269	0.29926384	$-2.8452129 \times 10^{-3}$	1.7117226×10^{-3}
T_b, °R	434.38878	50.125279	–0.9097293	7.0280657×10^{-3}	–601.85651
T	–0.50862704	8.700211×10^{-2}	$-1.8484814 \times 10^{-3}$	1.4663890×10^{-5}	1.8518106
γ	0.86714949	3.4143408×10^{-3}	-2.839627×10^{-5}	2.4943308×10^{-8}	–1.1627984
V_c, ft³/lb	5.223458×10^{-2}	$7.87091369 \times 10^{-4}$	$-1.9324432 \times 10^{-5}$	1.7547264×10^{-7}	4.4017952×10^{-2}

Ahmed (1985)

Example: p_c, T_c

Calculation of Reservoir Hydrocarbon Properties

predicting the physical properties of pure compounds and undefined hydrocarbon mixtures:

where θ = any physical property
a–f = constants for each property as ;
γ = specific gravity of the fraction
M = molecular weight

$$\theta = a\,(M)^b\,\gamma^c\,\mathrm{EXP}\,[d\,(M) + e\,\gamma + f\,(M)\,\gamma]$$

T_c = critical temperature, °R
P_c = critical pressure, psia (Table 1-4)
T_b = boiling point temperature, °R
V_c = critical volume, ft³/lb

θ	a	b	c	d	e	f
T_c, °R	544.4	0.2998	1.0555	-1.3478×10^{-4}	–0.61641	0.0
P_c, psia	4.5203×10^{4}	–0.8063	1.6015	-1.8078×10^{-3}	–0.3084	0.0
V_c ft³/lb	1.206×10^{-2}	0.20378	–1.3036	-2.657×10^{-3}	0.5287	2.6012×10^{-3}
T_b, °R	6.77857	0.401673	–1.58262	3.77409×10^{-3}	2.984036	-4.25288×10^{-3}

Riazi and Daubert (1987)

Example: p_c, T_c

Example

Calculate the gas compressibility factor (Z) under initial reservoir pressure and temperature are 3000 psia and 180°F

Reservoir component

Component	y_i
CO_2	0.02
N_2	0.01
C_1	0.85
C_2	0.04
C_3	0.03
i - C_4	0.03
n - C_4	0.02

Example

gas compressibility factor?

Solution

Component	y_i	T_{ci}, °R	$y_i T_{ci}$	p_{ci}	$y_i p_{ci}$
CO_2	0.02	547.91	10.96	1071	21.42
N_2	0.01	227.49	2.27	493.1	4.93
C_1	0.85	343.33	291.83	666.4	566.44
C_2	0.04	549.92	22.00	706.5	28.26
C_3	0.03	666.06	19.98	616.4	18.48
i - C_4	0.03	734.46	22.03	527.9	15.84
n - C_4	0.02	765.62	15.31	550.6	11.01

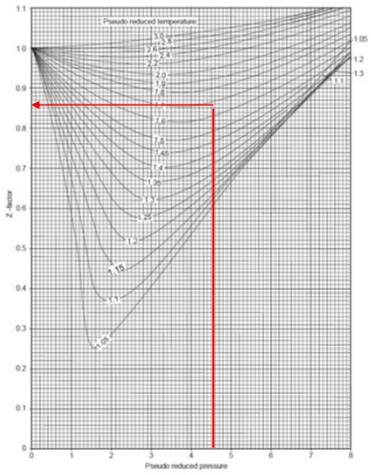
$T_{pc} = 383.38$ $\quad p_{pc} = 666.38$

$$T_{pc} = \sum_{i=1} y_i T_{ci} \qquad p_{pc} = \sum_{i=1} y_i p_{ci}$$

$$p_{pr} = \frac{p}{p_{pc}} \qquad p_{pr} = \frac{3000}{666.38} = 4.50$$

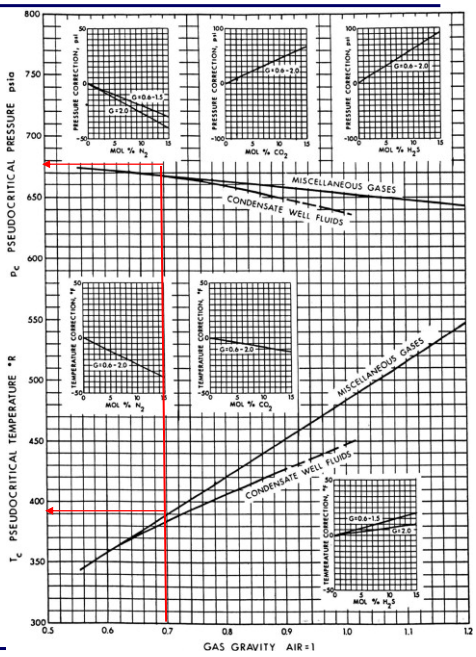
$$T_{pr} = \frac{T}{T_{pc}} \qquad T_{pr} = \frac{640}{383.38} = 1.67$$

From graph → $z = 0.85$



Example

Calculate the formation volume factor of a dry gas(B_g) with a relative density of 0.70 at reservoir temperature of 100 °C and reservoir pressure of 30 MPa.



At γ_g = 0.70 we have
T_{pc} = 389 °R = 389/1.8= 216 K and
p_{pc} = 663 psia=663/14.22= 45.1 kg/cm^2= 663/145=4.57MPa

$$T_{pr} = \frac{T}{T_{pc}} = \frac{(273+100)}{216} = 1.73 \quad \text{and} \quad p_{pr} = \frac{p}{p_{pc}} = \frac{30}{4.57} = 6.56$$

So, from Graph, we read Z = 0.943

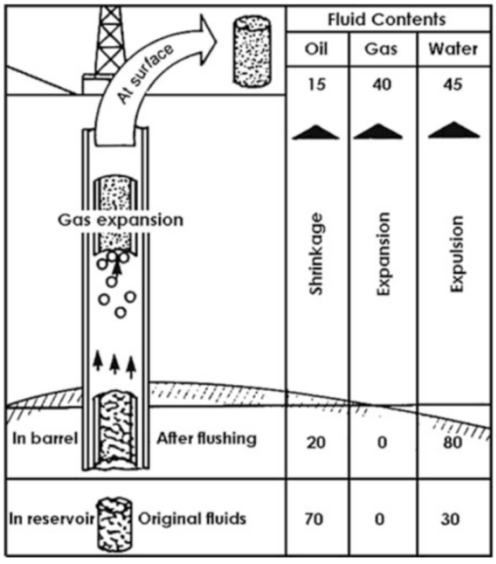
Second, calculate B_g

$$B_g = \frac{Z(273+t)}{293p} = \frac{0.943 \times (273+100)}{293 \times 30 \times 10} = 0.004$$

Petroleum Geomechanics

73

Example



Petroleum Geomechanics

74