Oil PVT Properties

Bubble point pressure (Pb) (or saturation pressure): It is the pressure at which the first gas bubble is liberated from the reservoir oil upon isothermal pressure reduction at the reservoir temperature.

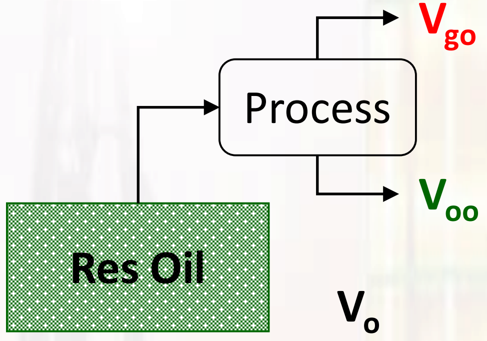
Oil Properties:

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

Note: Data on most of these fluid properties are usually determined by laboratory experiments performed on samples of actual reservoir fluids. In the absence of experimentally measured properties of crude oils, it is necessary for the petroleum engineer to determine the properties from empirically derived correlations.

- The description of volumetric properties oil properties are divided into two categories:
  - **Under saturated Oil** (Pi > Pb) - no free gas exists until the reservoir pressure falls below the bubble point pressure.
  - **Saturated Oil** (Pi ≤ Pb) – free gas (gas cap) exists in the reservoir.
- The volumetric behavior at the bubble-point is highly dependent upon the amount of solution gas.

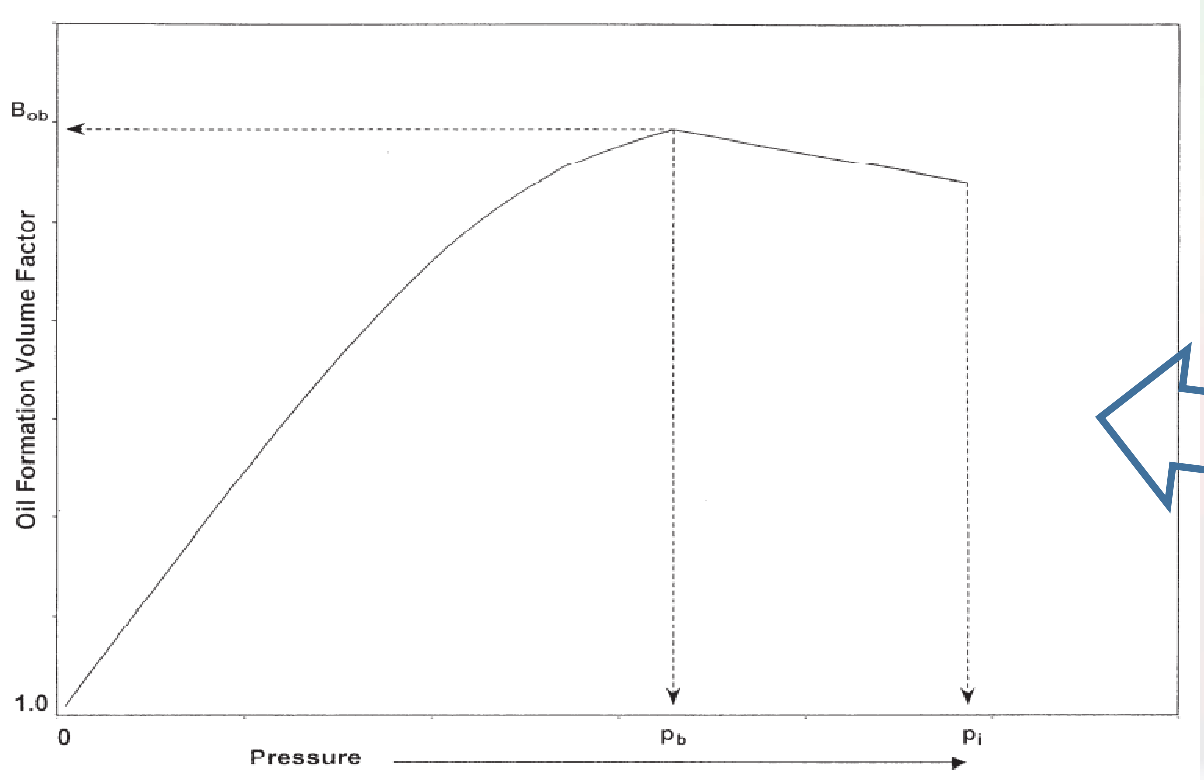
Oil Volume Factor [Formation Volume Factor (Bo)]



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

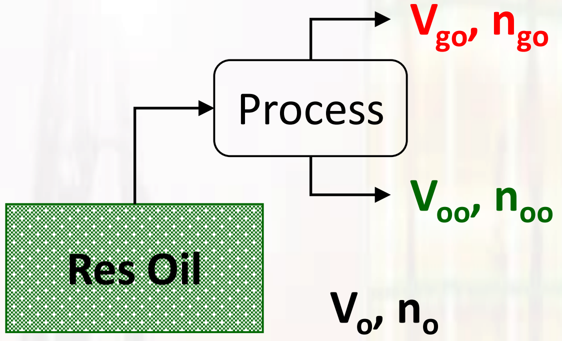
$$Bo = \frac{V\ at\ resevoir}{V\ at\ surface},\quad bbl/STB$$

- **It is defined as the ratio of the volume of oil at reservoir (in-situ) conditions to that at stock tank (surface 14.7 psia and 60 ℉) conditions.**
- **Bo is always greater than or equal to <u>unity</u>**
- **This factor, is used to convert the flow rate of oil (at stock tank conditions) to reservoir conditions.**



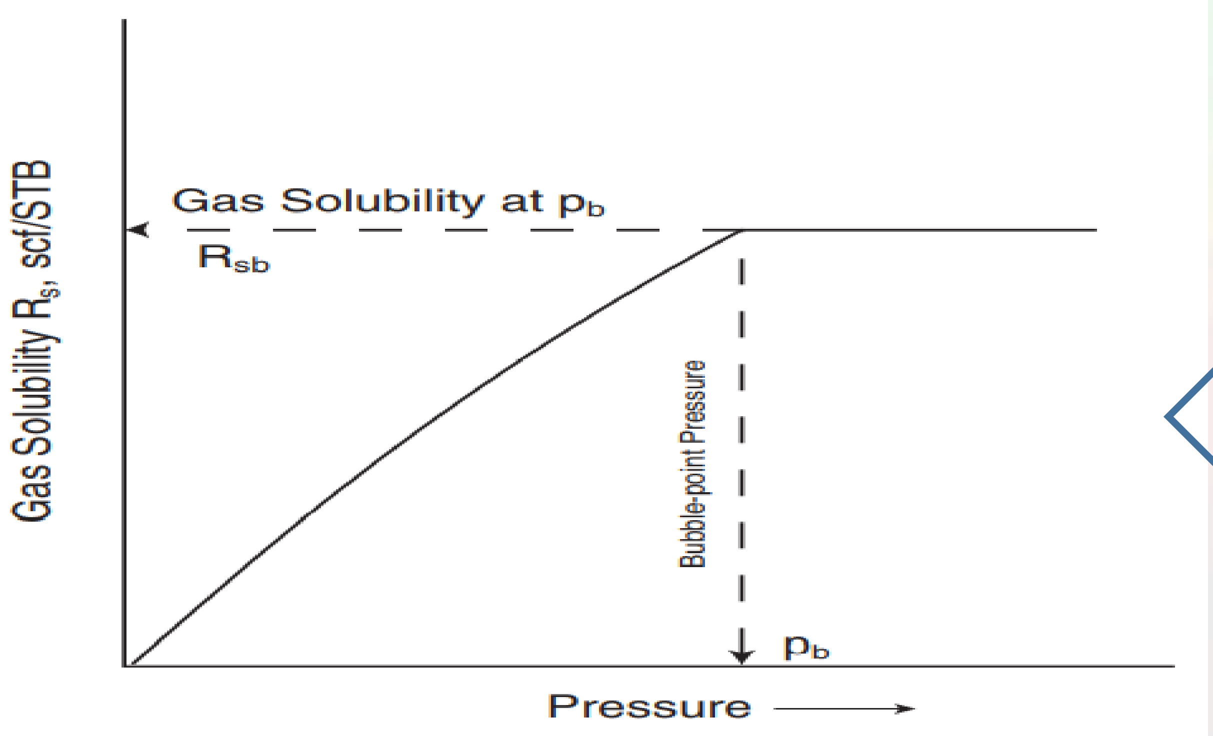
<u>Explanation :</u> As the pressure is reduced below the initial reservoir pressure pi , the oil volume increases due to the oil expansion. This behavior results in an increase in the oil formation volume factor and will continue until the bubble-point pressure is reached. At pb, the oil reaches its maximum expansion and consequently attains a maximum value of Bob for the oil formation volume factor. As the pressure is reduced below pb, volume of the oil and Bo are decreased as the solution gas is liberated. When the pressure is reduced to atmospheric pressure and the temperature to 60°F, the value of Bo is equal to one.

Solution Oil Gas Ratio (OGR)[Gas Solubility]



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

- The dissolved gas content of the liquid. Or it is expressed in terms of the total gas in solution per unit volume at any pressure. It is in SCF/STB units.
- ***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.
- It is constant above bubble point (Pb).



Explanation of Diagram : As the pressure is reduced from the initial reservoir pressure pi to the bubble-point pressure pb, no gas evolves from the oil and consequently the gas solubility remains constant at its maximum value of Rsb. Below the bubble-point pressure, the solution gas is liberated and the value of Rs decreases with pressure.

Crude Oil Gravity (specific gravity)

$$\gamma_o = \frac{\rho_o}{\rho_w}$$

$$\gamma_o = \frac{\rho_o}{62.4}, 60°/60°$$

Where:

γo = specific gravity of the oil

ρo = density of the crude oil, lb/ft³

ρw = density of the water, lb/ft³

And ρw = 62.4 lb/ft³

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

- **The specific gravity of a crude oil is defined as the ratio of the density of the oil to that of water. Both densities are measured at 60°F and atmospheric pressure.**
- **the liquid specific gravity is dimensionless, but traditionally is given the units 60°/60° to emphasize the fact that both densities are measured at standard conditions**
- **The API gravities of crude oils usually range from 47° API for the lighter crude oils to 10° API for the heavier asphaltic crude oils.**

oil Density

The crude oil density is defined as the mass of a unit volume of the crude at a specified pressure and temperature. It is usually expressed in pounds per cubic foot.

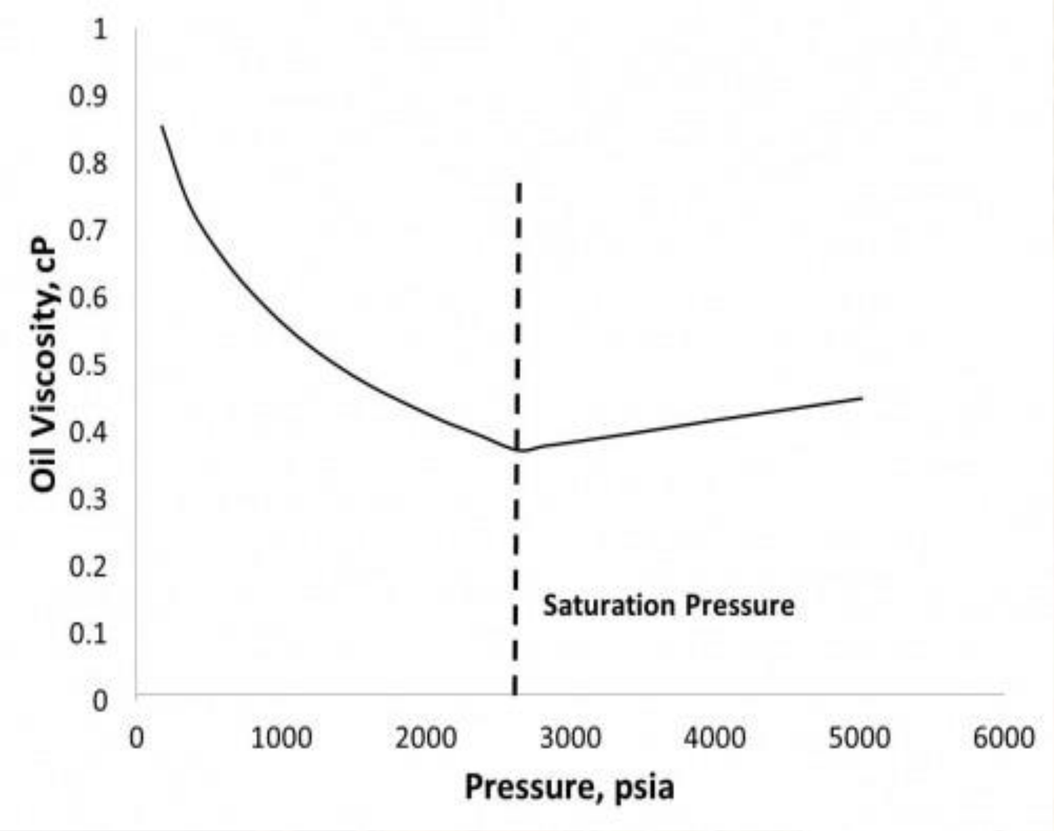
$$\rho_o = \frac{62.4\gamma_o + 0.0136 R_s \gamma_g}{B_o}$$

where

γo = specific gravity of the stock-tank oil Rs = gas solubility, scf/STB

ρo = oil density, lb/ft³

Crude oil viscosity (μo)



- **Oil Viscosity (μo)** is the resistance of fluid to flow because of the friction between its plates (i.e the internal resistance of the fluid to flow)
- Crude oil viscosity is an important physical property that controls and influences the flow of oil through porous media and pipes.
- The oil viscosity is a strong function of the **temperature**, **pressure**, **oil gravity**, **gas gravity**, and **gas solubility.**
- Oil viscosity increase with increasing STO density, decreasing temperature, and decreasing solution gas amount.
- The viscosity of crude oil ranges from about 0.3 cp for a gas saturated oil at reservoir conditions to about 1000 cp for a gas-free crude oil at atmospheric pressure and 100 FH.
- Two types of oil viscosity: Absolute and relative
- Two types of absolute viscosity of oil which are dynamic (in centipoises) and kinematic (in centistokes)

Gas PVT Properties

Gas Properties:

- Compressibility factor, Z.
- Density, ρ_{g}.
- Specific gravity, γ_{g}.
- Gas volume factor, B_{g}.
- Solution oil-gas ratio, Rs.
- Viscosity, μ_{g}.

The Ideal Gas Law

$$\boxed{pV = nRT}$$

Ideal gases:

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

p = Absolute Pressure

V = Total Fluid Volume

n = Number of Fluid Moles

Z = Compressibility Factor or Z-Factor

T = Temperature

R = Universal Gas Constant

$\approx 8314.472 \text{ Pa-m}^3\text{/kmol-K}$

$\approx 0.08314472 \text{ bara-m}^3\text{/kmol-K}$

$\approx 10.73159 \text{ psia-ft}^3\text{/lbmol-R}$

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

The Real Gas Law

$$\boxed{pV = ZnRT}$$

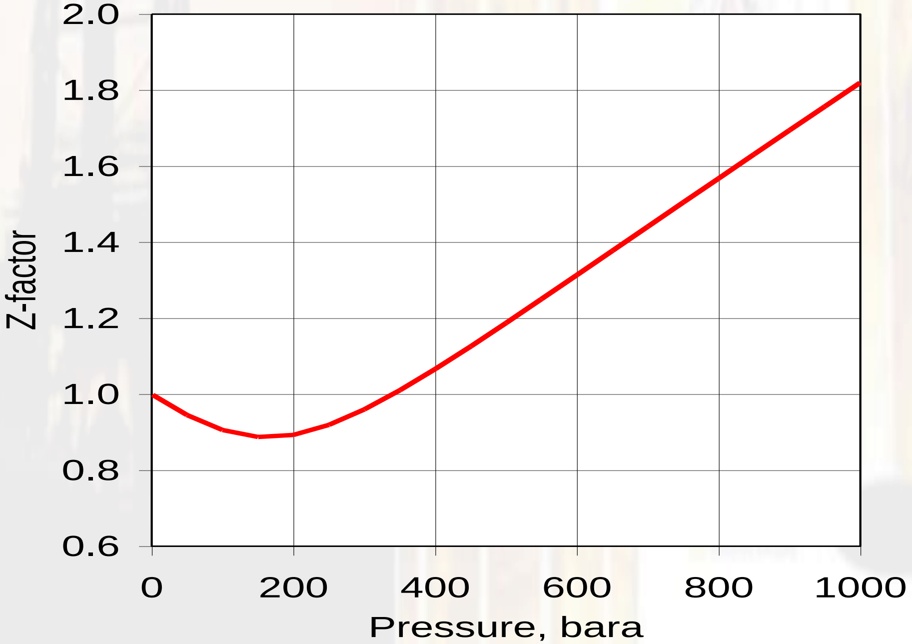
***Note:** Most gases show ideal behavior at low pressure and temperatures.*

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

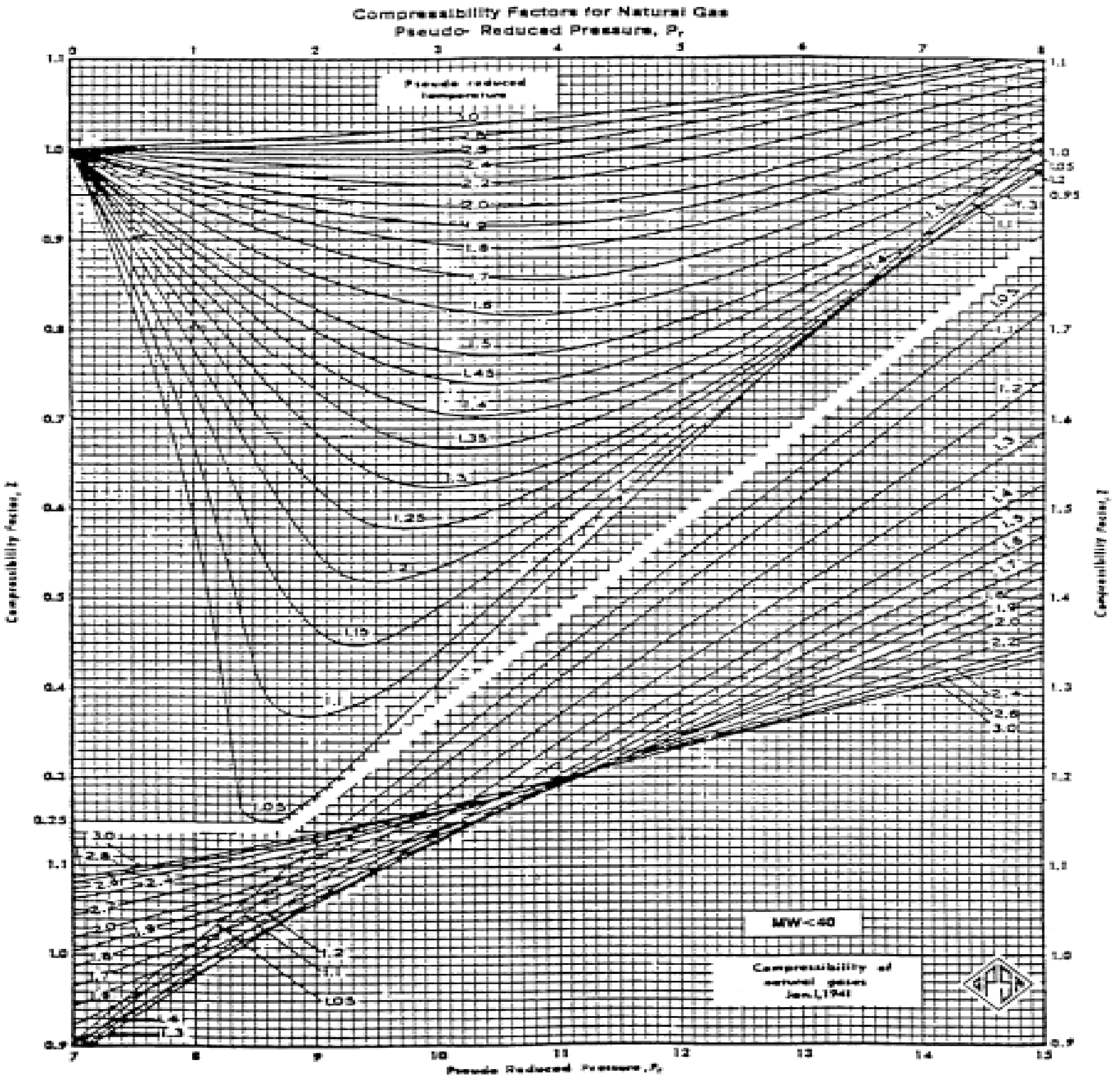
Compressibility Factor (Z-Factor)

The gas compressibility factor z is a dimensionless quantity and is defined as the ratio of the actual volume of n-moles of gas at T and p to the ideal volume of the same number of moles at the same T and p :

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



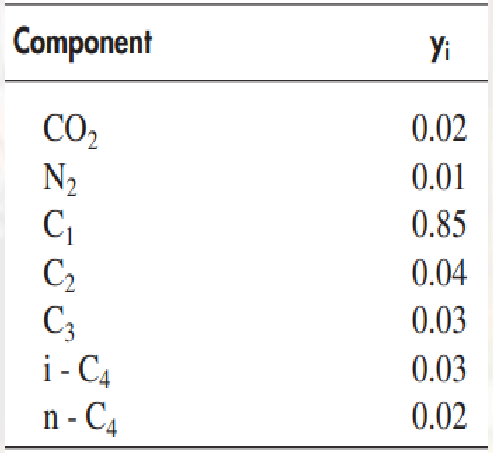
- The Z-factor gives accurate gas volumetric properties (B_g, ρ_g, c_g)
- The Z-factor is particularly important for estimating initial gas in place (IGIP = HCPV/B_g) and gas depletion recovery factors.
- Z-factor is a function of pressure p, temperature T, and gas composition y.
- Z-factor is usually expressed as function of pseudo-reduced pressure and temperature, $Z(p_{pr}, T_{pr})$, where $\mathbf{p_{pr}=p/p_{pc}}$ and $\mathbf{T_{pr}=T/T_{pc}}$.
- 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%.



Compressibility Factors for Natural Gas
Pseudo- Reduced Pressure, P_r
0
1
2
3
4
5
6
7
8
Pseudo reduced temperature
3.0
2.8
2.6
2.4
2.2
2.0
1.9
1.8
1.7
1.6
1.5
1.45
1.4
1.35
1.3
1.25
1.2
1.15
1.1
1.05
1.1
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.25
Compressibility Factor, Z
1.05
1.2
0.95
1.3
1.4
1.5
1.6
1.7
1.8
1.9
2.0
2.2
2.4
2.6
3.0
MW<40
Compressibility of natural gases Jan. 1, 1941
NGSMA
7
8
9
10
11
12
13
14
15
Pseudo Reduced Pressure, P_r

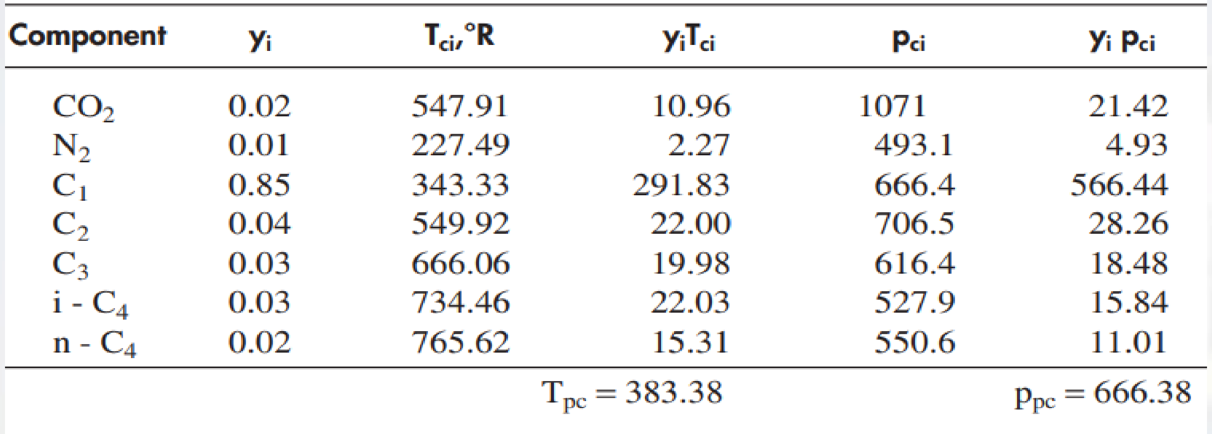
Example

A gas reservoir has the following gas composition: the initial reservoir pressure and temperature are 3,000 psia and 180°F, respectively. Calculate the gas compressibility factor under initial reservoir conditions.



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

solution



Component	y_i	T_{ci}, °R	y_iT_{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
			$T_{pc} = 383.38$		$p_{pc} = 666.38$

Step 1. Determine the pseudo-critical pressure and pseudo-critical temperature from

$$p_{pc} = \sum_{i=1} y_i\ p_{ci} \qquad P_{Pc} = 666.18$$

$$T_{pc} = \sum_{i=1} y_i\ T_{ci} \qquad T_{Pc} = 383.38$$

Step 2. Calculate the pseudo-reduced pressure and temperature where **p_{pr}=p/p_{pc}** and **T_{pr}=T/T_{pc} so:**

P_{Pr} = 3000/666.18 = 4 50 and T_{Pr} = (180+460)/383.38 = 1.67

Step 3. Determine the z-factor from Figure, so

Z = 0.85

Gas specific gravity

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

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

Where:
ɣg = gas specific gravity
ρair = density of the air
Mair = apparent molecular weight of the air = 28.96
Mg = apparent molecular weight of the gas
Psc = standard pressure, psia
Tsc = standard temperature, °R

- **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 (Bg)

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

Applying the real gas equation-of-state and substituting for the volume V, gives:

$$B_g = \frac{\frac{znRT}{p}}{\frac{z_{sc}\, n\, R\, T_{sc}}{p_{sc}}} = \frac{p_{sc}}{T_{sc}}\frac{zT}{p}$$

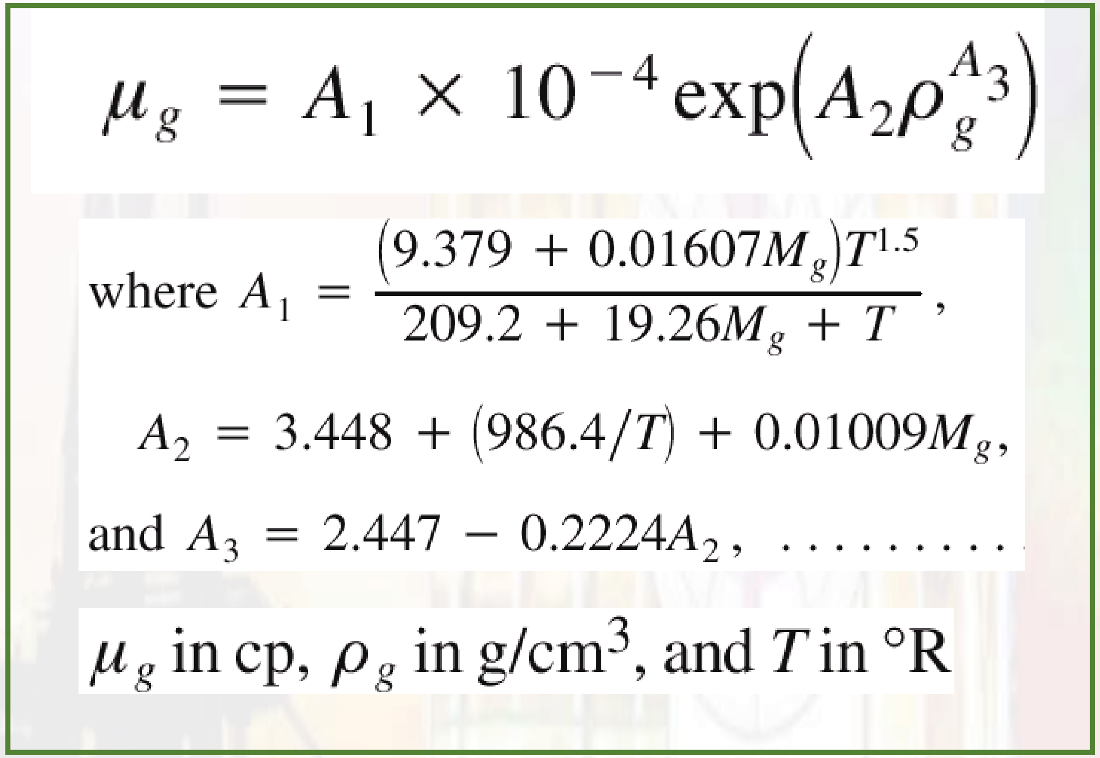
$$\boxed{B_g = \left(\frac{p_{sc}}{T_{sc}}\right)\frac{ZT}{p}} \Rightarrow B_g = 0.02827\frac{zT}{p}$$

where Zsc = z-factor at standard conditions = 1.0
Psc, Tsc = standard pressure and temperature

- **Gas volume factor is defined as the ratio between gas volume at p and T to the *ideal* gas volume at standard conditions (60°F and 14.7 psia).**
- **The gas formation volume factor is used to relate the volume of gas, as measured at reservoir conditions, to the volume of the gas as measured 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.**

Gas Viscosity

Lee-Gonzalez gas viscosity correlation



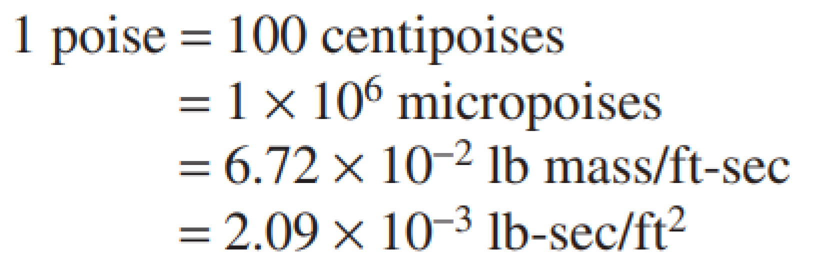
$$\mu_g = A_1 \times 10^{-4} \exp\left(A_2 \rho_g^{A_3}\right)$$

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

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

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

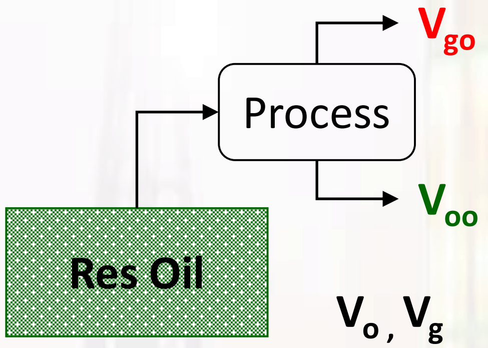
μ_g in cp, ρ_g in g/cm^3, and T in °R



$$\begin{aligned} 1 \text{ poise} &= 100 \text{ centipoises} \\ &= 1 \times 10^6 \text{ micropoises} \\ &= 6.72 \times 10^{-2} \text{ lb mass/ft-sec} \\ &= 2.09 \times 10^{-3} \text{ lb-sec/ft}^2 \end{aligned}$$

- 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.

The total formation volume factor (Bt)



$$B_t = \frac{(V_o)_{p,T} + (V_g)_{p,T}}{(V_o)_{sc}}$$

where Bt = total formation volume factor, bbl/STB
(Vo)p,T = volume of the oil at p and T, bbl
(Vg)p,T = volume of the liberated gas at p and T, bbl
(Vo)sc = volume of the oil at standard conditions, STB

- **Bt is defined as the ratio of the total volume of the hydrocarbon mixture (i.e., oil and gas, if present), at the prevailing pressure and temperature per unit volume of the stock-tank oil. Because naturally occurring hydrocarbon systems usually exist in either one or two phases, the term two-phase formation volume factor has become synonymous with the total formation volume.**

$$B_t = B_o + (R_{sb} - R_s)B_g$$

where Rsb = gas solubility at the bubble-point pressure, scf/STB
Rs = gas solubility at any pressure, scf/STB
Bo = oil formation volume factor at any pressure, bbl/STB
Bg = gas formation volume factor, bbl/scf

Explanation: As pointed out above, Bo and Bt are identical at pressures above or equal to the bubble-point pressure because only one phase, the oil phase, exists at these pressures. It should also be noted that at pressures below the bubble-point pressure, the difference in the values of the two oil properties represents the volume of the evolved solution gas as measured at system conditions per stock-tank barrel of oil