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PVT Properties of Black Crude Oil

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Abstract

Precise PVT studies and behavior of phase-equilibrium of petroleum reservoir fluids are essential for describing these fluids and appraising their volumetric behavior at several pressure stages. There are numerous laboratory studies that can be performed on a reservoir sample. The amount of data desired determines the number of tests to be performed in the laboratory. Generally, there are three laboratory tests which characterize hydrocarbon fluids, namely primary study, constant mass depletion, and differential vaporization test. Generally, PVT properties are determined either experimentally or calculated theoretically through published correlations. This chapter presents different PVT laboratory tests that are required to understand the phase behavior of black oils.

Keywords: PVT experiments, black oil properties, petroleum reservoirs

1. Introduction

Petroleum (an equivalent term is a crude oil) is a complex mixture consisting predominantly of hydrocarbons and containing sulfur, nitrogen, oxygen, and helium as minor constituents. The physical and chemical properties of crude oils vary considerably and depend on the concentration of the various types of hydrocarbons and minor constituents present. Crude oil reservoirs are classified according to initial reservoir pressure into the following categories: (1) undersaturated oil reservoir; in which initial reservoir pressure is greater than the bubble point pressure of reservoir fluid; (2) saturated oil reservoir; in which initial reservoir pressure is equal to the bubble point pressure of reservoir fluid; (3) gas-cap reservoir; in which initial reservoir pressure is below the bubble point pressure of reservoir fluid, so reservoir is termed as gas-cap or two-phase reservoir, since the gas or vapor phase is underlain by an oil phase. Petroleum hydrocarbons exist as gaseous or liquid phase depending on reservoir temperature. If it is higher than the critical temperature of the fluid, the reservoir fluid is gas. Otherwise, the reservoir fluid is oil [1]. Black oil reservoir is considered as one of the most precious reservoir fluids. It constitutes the majority of oil reservoirs and exists in every basin. An accurate description of physical properties of crude oils is of considerable importance in the fields of both applied and theoretical science and, especially, in the solution of petroleum reservoir engineering problems. Some of these physical properties are of primary interest in petroleum engineering studies and detected through PVT tests which aim to determine reservoir fluid behavior at simulated reservoir conditions. Data on these fluid properties is 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.

However; correlations are approximations and may be useful only in regional geological provinces.

Crude oils cover a wide range of physical properties and chemical compositions and are classified into black oils and near-critical or volatile-oils [2] depending on their phase behavior. The phase diagrams of two reservoir types are illustrated in **Figures 1** and 2, while their physical properties are indicated in **Table 1** according to classifications established by Moses [1], McCain [3], Whitson and Brule [4]. From the phase diagram, following the pressure reduction path as indicated by the vertical line EF, the iso-lines are scattered uniformly around the reservoir temperature which can be located at any region between points C&F. It is apparent that the

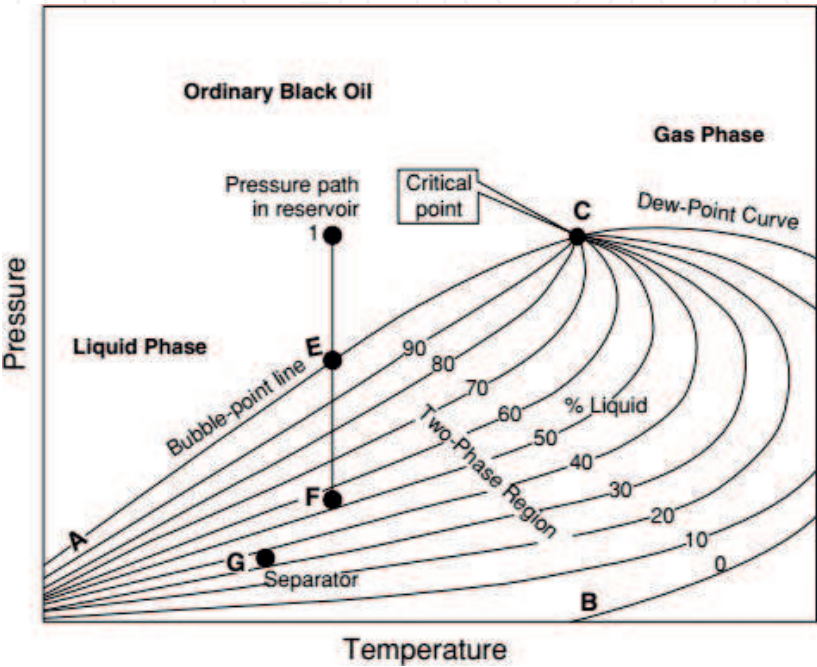


Figure 1.
Typical phase diagram for black oil [8].

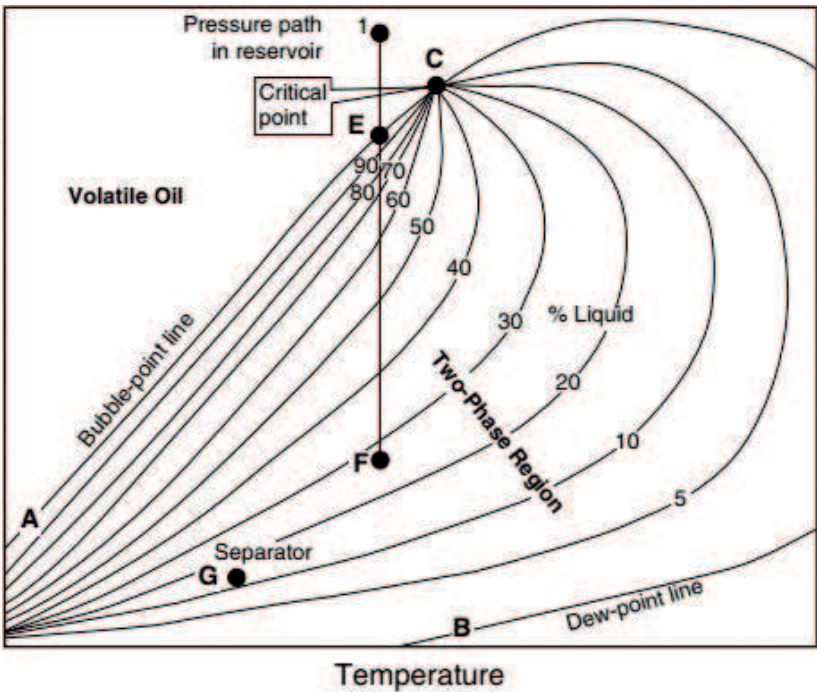


Figure 2.
Typical phase diagram for volatile oil [8].

Property	Black oil [7, 9]	Volatile oil [1]
Fluid color	Deep black	Light colored turn to slightly reddish
Mole % of heptane plus (C ₇ ⁺)	>17.5% up to 26.5%	12.5–17.5%
(GOR)	~1500–1750 & up to 2000 scf/STB	2000–3000 scf/STB
API	< 45°	~40° or higher
C _o	3–150 × 10 ⁻⁶ psi ⁻¹ (under-saturated to highly saturated GOR oils)
β _o	<2 rbbl/STB	>2 rbbl/STB

Table 1.
Criteria of black and volatile oil reservoirs.

reservoir temperature (T_{res}) in black oil reservoirs is less than the critical temperature (T_c). Moreover, the liberated gas below the bubble point pressure is considered as lean gas for industrial applications [5]. While in volatile oils, T_{res} is closest to the critical temperature. Another important differentiation lies in the volume of evolved gas below bubble point which is much greater in volatile oil than that observed for black oils [6]. Another important factor comprising gas oil ratio (GOR), and mole % of C_7^+ , where GOR is obtained from field data and the mole % of C_7^+ is obtained from composition analysis. PVT properties for black oils in almost all reservoirs are required for production and surface facilities calculations to manage, develop, and forecast oil field behavior [7], as well as maximizing economic profit.

PVT analysis is utilized by reservoir engineers to distinguish physical properties of reservoir fluids and variations in the volume and phase state that occurs during oil production [10, 11]. The phase envelope is characterized by some physical criteria such as oil formation volume factor, saturation pressure, gas oil ratio, oil density, oil viscosity, and oil isothermal compressibility. This phase envelope may be drawn through experimental data points or via software packages like PVTp, PVTsim, Eclipse and so on, based on the differential equation of states. The importance of PVT properties for reservoir performance analysis makes a dire need to develop a convenient way to predict these properties mathematically either by empirical correlations or equations of state. These empirical relations comprise two types. The first one belongs to the black oil type which forecast PVT behavior from the available PVT data, including saturation pressure, reservoir temperature, oil API index, gas-oil ratio, and reservoir pressure. The second one belongs to compositional models which rely on the equation of states and its hybrids. In these models besides PVT parameters, other measurements including fluid composition, critical temperature, molar masses and components acentric factor are utilized [12, 13]. Although accuracy of the empirical PVT correlations is often limited due to variations and complexity of multicomponent reservoir fluid systems, these correlations still used on field scale [14–17].

2. PVT physical parameters and black oil modeling

In a black oil reservoir, the oil and gas formation volume factors, gas densities, the solution gas-oil ratio, and the viscosities of oil and gas are measured at reservoir temperature as a function of pressure. Once these measurements are, they can be

applied in empirical correlations to obtain the relative in situ amounts of oil and gas during the production life of the reservoir.

2.1 Crude oil API gravity

Crude oil density is defined as the mass of a unit volume of the crude at a specified pressure and temperature and expressed in g/cc. In typical oil reservoirs, the oil density decreases with pressure depletion until it reaches the lowest value at the bubble point. The higher oil density at higher pressures resorts to the high oil molecules compressing per the unit volume. By reducing pressure beneath the bubble-point pressure, the gas is ejected from the solution which forms a free gas. The released gas is saturated with some of oil intermediate components, while the heavier one remains in the reservoir. These intermediates release results in the density reversal trend versus pressure beneath the saturation pressure. It is calculated either by compositional models or by correlating parameters. The API gravity is the preferred gravity scale, and related to the specific gravity which is defined as the ratio of the oil density to water density at 60°F and atmospheric pressure by the following relation:

$$API = \frac{141.5}{\gamma_o} - 131.5 \quad (1)$$

2.2 Solution gas specific gravity

It is a dimensionless property that represents the ratio between hydrocarbon gas density and the air density at standard conditions. It is ascribed practically by the weighted average of the specific gravities of the separated gas from each separator, and expressed by the following relation:

$$\gamma_g = \frac{\sum_{i=1}^n (R_{sep})_i (\gamma_{sep})_i + R_{st} \gamma_{st}}{\sum_{i=1}^n (R_{sep})_i + R_{st}} \quad (2)$$

2.3 Gas solubility

It is defined as the number of standard cubic feet of gas that dissolve in one stock-tank barrel of crude oil at certain pressure and temperature and defined in SCF/STB [18].

$$R_s = \frac{(V_g)_{P,T}}{(V_o)_{sc}} \quad (3)$$

At standard conditions, dissolved gas is completely released from the oil, and therefore the oil contains no gas. Gas solubility increase with pressure increasing until it reaches the maximum value at saturation pressure. Below the bubble point pressure, gas is evolved with reduction in pressure and the gas solubility also decreases. Generally, the lighter the oil the higher the gas solubility, therefore volatile oils often has a higher solution GOR than black oils.

2.4 Bubble point pressure

It is defined as the highest pressure at which a bubble of gas is first liberated from the oil, and is determined experimentally by conducting a constant mass

depletion test or estimated from empirical correlations. By reservoir pressure depletion beneath the saturation pressure, a released gas is formed in the reservoir. Since gas mobility is greater than the oil mobility, the produced GOR increase with continual pressure depletion beneath the saturation pressure. Other PVT properties are also greatly affected by reservoir pressure depletion.

2.5 Isothermal oil compressibility

It is the change in the fluid volume with respect to the change in pressure at isothermal conditions, expressed in psi^{-1} and calculated above the bubble point pressure from Eqs. (4 and 5).

$$C_o = -\frac{1}{d_v} \frac{d_v}{d_p} \quad (4)$$

$$C_o = -\frac{1}{B_o} \left[\left(\frac{\partial B_o}{\partial P} \right)_T - B_g \left(\frac{\partial R_s}{\partial P} \right)_T \right] \quad (5)$$

Oil compressibility is determined during constant mass depletion test. In that procedure, the oil in the PVT cell is allowed to expand by reducing the pressure, and both the increase in oil volume and the decrease in oil pressure are measured. Oil compressibility above the saturation pressure greatly affects the material balance calculations for estimating volumetric reserve in oil reservoirs, as well as pressure transient analysis for under-saturated oils. Moreover, it is used in the estimation of vertical lift performance.

2.6 Gas compressibility factor

It is a dimensionless quantity used for gas correction at higher pressures and temperature, calculated from the basic equation of state as

$$Z = \frac{PV}{nRT} \quad (6)$$

2.7 Oil formation volume factor, B_o

It is defined as the ratio of oil volume either at the reservoir or separator condition to the volume of oil at standard conditions.

$$(B_o)_{res} = \frac{(V_o)_{(p,T)res}}{(V_o)_{sc}} \quad (7)$$

$$(B_o)_{sep} = \frac{(V_o)_{(p,T)sep}}{(V_o)_{sc}} \quad (8)$$

The oil formation volume factor is expressed in units of reservoir volume over standard volume (bbl/STB). At the surface, the oil loses the dissolved gas it contained under high pressure and temperature in the reservoir. By pressure decline from reservoir to surface conditions, the following scenarios are generated:

- (1) The oil weight decrease owing to the loss of dissolved gas by pressure decrease;
- (2) The oil volume reduced slightly owing to the temperature reduction, however, the oil slightly expands owing to the pressure decrease. The volume reduction and expansion due to temperature and pressure successively usually cancel each other and no significant changes occur. Practically, (B_o) is determined from residual oil

volume at 60°F at the end of differential liberation. The increase in B_o above bubble point pressure represents oil expansion by pressure decline so the oil volume at P & T (the numerator in Eq. 8) increase and consequently B_o increase. Below bubble point, the oil shrinkage due to gas evolving tends to overcome its expansion by pressure reduction, consequently B_o decline steeply.

2.8 Gas formation volume factor, B_g

Defined as the ratio of the gas volume at the temperature and pressure of any stage below the bubble point and the volume of the same gas at standard conditions

#	Property		Input parameters
1	Bubble point pressure (P_b)		Reservoir temperature (T_{res}); API; gas solubility (R_s); the specific gravity of the solution gas (γ_g); oil specific gravity (γ_o); separator gas gravity ($\gamma_{g\ sep}$); reservoir pressure (P_{res}); separator pressure (P_{sep}); separator temperature (T_{sep})
2	Crude oil gravity (API)		The specific gravity of the solution gas (γ_g); oil specific gravity (γ_o)
3	The specific gravity of the solution gas (γ_g)		Separator GOR (R_{sp}); separator gas gravity (γ_{sep}); GOR from the stock tank (R_{st}); gas gravity from the stock tank (γ_{st})
4	Oil density (ρ_o)		The molecular weight of the stock tank oil (M_{STO}); API; gas solubility (R_s); the specific gravity of the solution gas (γ_g); reservoir temperature (T_{res}); reservoir pressure (P_{res})
5	Gas solubility (R_s)		Reservoir temperature (T_{res}); reservoir pressure (P_{res}); oil density (ρ_o); API; the specific gravity of the solution gas (γ_g); oil specific gravity (γ_o); separator pressure (P_{sep}); separator temperature (T_{sep}); oil formation volume factor (B_o)
6	Oil formation volume factor (B_o)		Reservoir temperature (T_{res}); reservoir pressure (P_{res}); oil density (ρ_o); API; specific gravity of the solution gas (γ_g); oil specific gravity (γ_o); separator pressure (P_{sep}); separator temperature (T_{sep}); isothermal compressibility (C_o); bubble point pressure (P_b); gas solubility (R_s)
7	Isothermal compressibility (C_o)	Above bubble point (P_b)	Reservoir pressure ($P_{res} > P_b$); oil density (ρ_o); API; specific gravity of the solution gas (γ_g); separator pressure (P_{sep}); separator temperature (T_{sep}); bubble point pressure (P_b); gas solubility at the bubble point pressure (R_s)
		Below bubble point (P_b)	Reservoir temperature (T_{res}); reservoir pressure ($P_{res} < P_b$); API; specific gravity of the solution gas (γ_g); oil specific gravity (γ_o); oil formation volume factor (B_o); gas formation volume factor (B_g); bubble point pressure (P_b); gas solubility (R_s)
8	Oil viscosity (μ_o)	Dead oil viscosity (μ_{od})	Reservoir temperature (T_{res}); API
		Saturated oil viscosity (μ_{ob})	Reservoir temperature (T_{res}); reservoir pressure (P_{res}); API; specific gravity of the solution gas (γ_g); oil specific gravity (γ_o); bubble point pressure (P_b); gas solubility (R_s); oil density at bubble point (ρ_{ob}); dead oil viscosity (μ_{od})
		Under-saturated oil viscosity (μ_{ou})	Reservoir pressure (P_{res}); API; bubble point pressure (P_b); gas solubility (R_s); dead oil viscosity (μ_{od}); saturated oil viscosity (μ_{ob})

Table 2.
Major input parameters for PVT equations.

through differential liberation (Eq. 9). B_g can also be calculated from composition analysis as a function of Z-factor as stated in Eq. 10.

$$B_g = \frac{(V_g)_{P,T}}{(V_g)_{sc}} \quad (9)$$

$$B_g = \frac{0.028269Z(T)_R}{(P)_{psia}} \quad (10)$$

2.9 Crude oil viscosity

It is defined as the resistance of the fluid to flow, expressed in centipoise (cp). It is affected by the oil composition, GOR, and reservoir temperature. Oil viscosity represents internal dynamic fluid friction relevant to fluid layers. Higher and lower viscosity depends on the gas/oil ratio. The behavior of viscosity is similar to that of density since oil viscosity shrinks with pressure decrease, owing to reduced friction between fluid layers, and reaches its minimal at the saturation pressure. With further pressure depletion more and more gas escaped from the oil, so the oil becomes denser and more viscous owing to loss of lighter components. Practically oil viscosity is measured by falling ball viscometer.

Table 2 summarizes some of the input physical parameters used to characterize black oil reservoirs.

3. Experimental PVT analysis

Crude oil samples can be obtained from downhole using a wireline sampling chamber, or at the separator, using separation facilities [19]. To carry a successful PVT analysis, the samples should be generated through the following procedure:

3.1 Sample handling

The pressurized liquid sample is heated to 200°F and stabilized in single phase prior to removal of any sample in order to ensure sample integrity and avoid any wax precipitation.

3.2 Sample validation

Carried out for both surface and bottom hole samples to ensure that no leakage occurs for the samples and the fluid virtually represents the reservoir.

3.2.1 Surface samples obtained from separator

They are subjected to assuring cylinders integrity during transportation through measurement of opening pressures of the separator oil cylinder and separator gas cylinder at ambient temperature and separator temperature. If the measured pressure equals the separator pressure, the sample is valid, otherwise, the sample is invalid. Moreover, quality control of separator samples carried out through measurement of the saturation pressure (bubble point) of the separator oil sample at the separator temperature and compared with the separator pressure. The sample was then transferred to the Lab cylinder, and the amount of water if present in the separator oil was determined, and discharged.

3.2.2 Bottom hole sample

Also, check cylinders' integrity during transportation and sampling carried out by measurement of sample opening pressures at transferring temperature and reservoir temperature. The sample cylinder was then agitated and transferring to Lab cylinder at reservoir temperature and pressure of 1000 psi above reservoir pressure.

3.3 Primary study

3.3.1 Surface samples obtained from separator

A primary study carried only for surface samples is as follows:

3.3.1.1 Atmospheric flashing of separator oil

A portion of the separator oil sample was charged to a high-pressure visual PVT cell and thermally expanded to the separator temperature till equilibrium. The sample was subjected to flash separation from separator conditions to standard conditions of 14.73 psia and 60°F. Dissolved gas-oil ratio and oil formation volume factor were calculated using the volumetric data obtained so that the supplied stock-tank oil rate could be adjusted to separator oil rate for the well-stream calculations. The density and API gravity of the stock-tank oil were also measured using density meter. The dissolved gas composition was determined using extended gas chromatography and the flashed liquid by high-resolution capillary gas chromatography. The two analyses were then mathematically recombined according to the dissolved gas-oil ratio to get the composition of separator oil. **Figure 3** illustrates the primary study procedure.

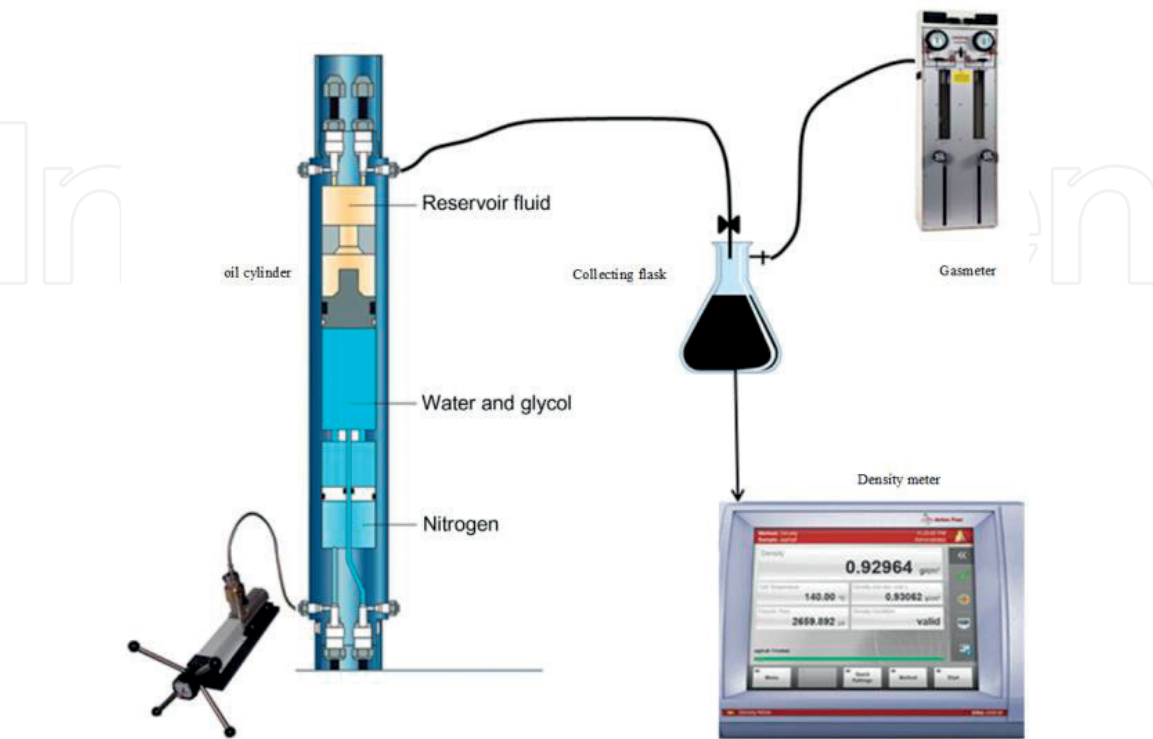


Figure 3.
Diagram of the primary study steps.

3.3.1.2 Composition analysis of stock-tank oil

The compositions of paraffins and aromatics in liquid samples were determined using Clarus 500 Perkin Elmer Gas Chromatograph connected with flame ionization detector (FID) using selective PIONA capillary column of 100 m in length and 0.25 mm internal diameter. Suitable sample capacity was injected into split / splitless injector through a microsyringe according to both response and linear range of FID detector. Nitrogen gas was used as carrier gas at its optimum flow rate. The system enables to detect the composition up to C_{36}^+ . Further oil analysis includes density, viscosity, pour point, and distillation analysis, in addition to water, basic sediment (BS) and sulfur contents, in order to determine the oil quality.

3.3.1.3 Gas composition analysis

The analysis of both separator gas and dissolved gas were determined according to ASTM 1945, using Clarus 500 PerkinElmer Gas Chromatograph online with the condensate cell utilizing four packed columns connected in series with thermal conductivity detector and DP-1 capillary column matched with flame ionization detector. Helium was used as carrier gas and the oven isothermal temperature 100°C in order to provide highly efficient detection of aromatics and hydrocarbons paraffin (normal and *iso*) from methane (C_1) up to undecane (C_{11}) components and non-hydrocarbons including H_2S , CO_2 , and N_2 . Once repeatability is verified, the validated bottle generated to proceed the complete PVT analysis, which, in the case of the reservoir fluid be a black oil, is composed by three main assays; constant mass depletion (CMD), differential liberation (DL), and separator test.

3.3.1.4 Measurement of density

The density of oil is measured by Anton Paar Density Meter. The density meter is calibrated with air and distilled water. The procedure reference is ASTM D-4052.

3.3.1.5 Measurement of molecular weight

The average molecular weight number is determined by using cryoscopy, (freezing point depression of benzene).

3.3.1.6 Corrected and adjustment of field separator GOR

Adjustment of field GOR carried out in the lab through the following equations, owing to higher deviations of the measured field gas deviation factor (Z_f)

$$\text{corrected separator GOR} = \left(\text{field GOR} \times \frac{\rho_f \times Z_f}{\rho_l \times Z_l} \right)^{0.5} \quad (11)$$

$$Z_f = \left(\frac{1}{f_{pv}} \right)^{0.5} \quad (12)$$

$$\text{adjusted separator GOR} = \frac{\text{corrected separator GOR}}{B_o} \quad (13)$$

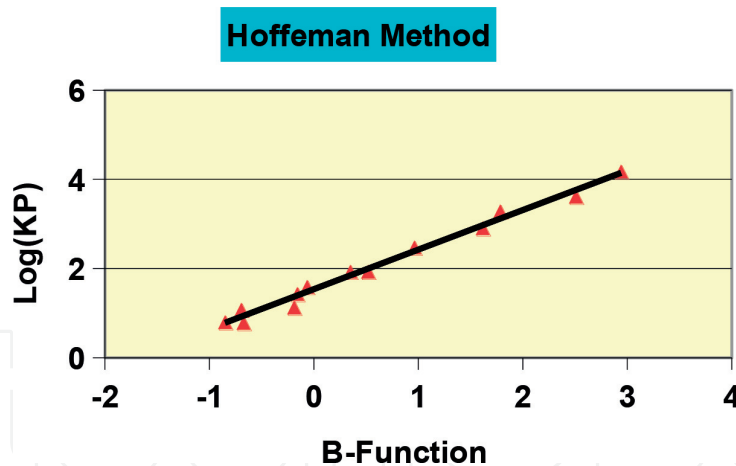


Figure 4.
Hofmann QC-plot.

3.3.1.7 Quality control of primary study

Carried out by applying Hoffmann method to data of separator oil & gas through plotting of $(K_i P_{sep})$ against $[1/B_i(1/T_{bi} - 1/T_{sep})]$ on a Cartesian scale which results in a straight line, as shown in **Figure 4**.

where,

$$K_i = \frac{y_i}{x_i} \quad (14)$$

$$B_i = \log(P_{ci}/14.7)/(1/T_{bi} - 1/T_{ci}) \quad (15)$$

3.3.1.8 Physical recombination of well stream

The samples were physically recombined at separator conditions (P_{sep} & T_{sep}) using the corrected separator (GOR), (B_o) and (B_g) to form the wellstream. The wellstream composition can mathematically be determined by applying material balance equation to the separator product compositional analysis and their physical properties such as corrected separator GOR, dissolved GOR, B_o , the density of stock tank oil, separator oil and gas densities as well as B_g .

3.3.2 Bottom hole sample (BHS)

A known portion of the reservoir fluid was charged from (BHS) cylinder to a high-pressure visual cell and thermally expanded to the reported reservoir temperature and pressure. After establishing thermal equilibrium, the fluid sample was subjected to a flash separation at standard conditions ($P = 14.7$ psia & $T = 60^\circ\text{F}$). The flashed data were then checked using Hoffmann method.

3.4 Constant mass depletion (CMD)

An integrated and automated mercury free system (PVT-cell) is used for PVT analysis of black-oil and volatile oil. A portion of the sample is pumped into the cell, and the volume and, therefore, pressure of the sample chamber are controlled with a piston. Most sample chambers are equipped with a magnetic stirrer to ensure that the system is well mixed. Constant mass depletion also known as flash liberation, in which a set of volume measurements as a function of pressure at fixed reservoir

temperature are performed within the PVT cell. The recombined well stream was pressurized and heated to reservoir temperature and pressure. A portion of the sample (~100 cc of live oil) was charged to a high-pressure visual PVT cell and thermally expanded to the reservoir temperature and the pressure was adjusted to a pressure of 1000 psi higher than the reservoir pressure. The measurements of pressures and volumes were recorded and then used to determine the bubble point pressure of the under-saturated reservoirs at reservoir temperature. Above bubble point pressure, the relative volume, oil formation volume factor, oil compressibility, density, and viscosity were determined, while below bubble point pressure the Y-Function is calculated at each pressure step.

3.5 Differential liberation (DL)

After the constant composition mass depletion, the sample was pressurized and equilibrated to a single phase condition. A differential vaporization procedure is then performed for the purpose of measuring two-phase properties as a function of reservoir pressure depletion. As with the flash expansion test, the volume of the sample chamber is increased incrementally; however, in this case, the evolved solution gas is withdrawn from the sample chamber after each incremental expansion. At each pressure depletion, the oil formation volume factor, gas formation volume factor, two-phase volume factor, gas gravity, gas solubility, density, and viscosity were determined. The viscosity of the evolved gas is usually calculated through Lee et al. correlations rather than measured. While the viscosity

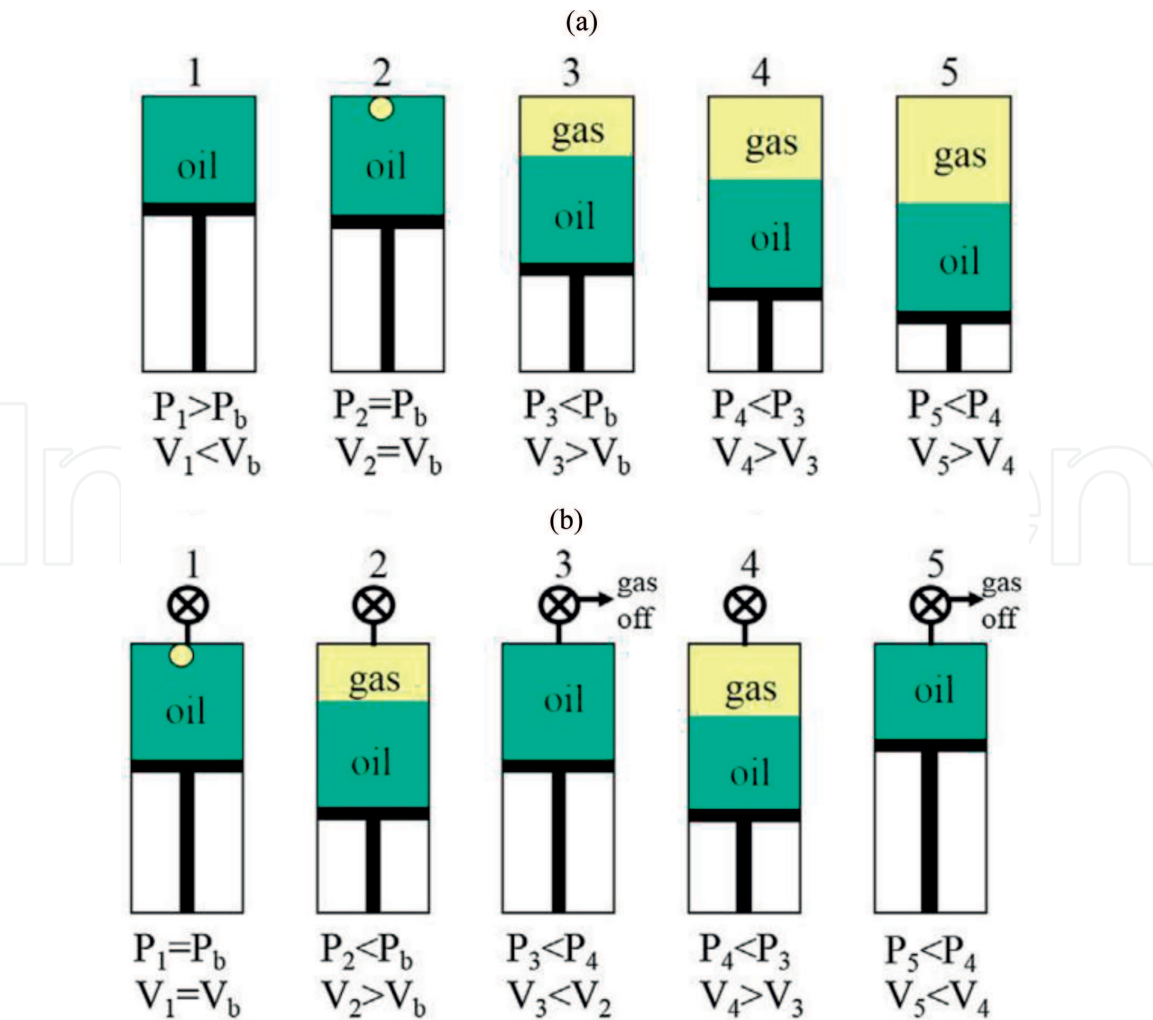


Figure 5.
Schematic illustration of (a) constant mass depletion and (b) differential liberation [6].

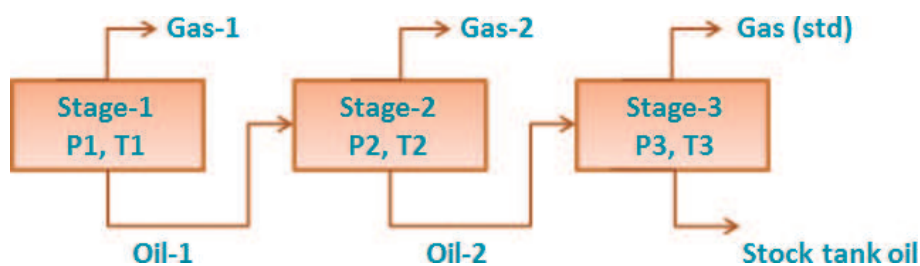


Figure 6.
Multistage separator test.

measurement for both live and dead oil is carried out over a wide range of high pressure and temperature by a rolling ball viscometer (RUSKA). Schematic representation of CMD and differential liberation are shown in **Figure 5**.

3.6 Separator test

Separator test is used to determine the effect of surface separation parameters on the gas-oil ratio, stock tank oil gravity and formation volume factor at separator conditions. About 100 cc of the recombined sample is raised to the saturation pressure at the reservoir temperature. Then the sample condition is lowered and adjusted to the separator conditions, where the oil and gas volumes are measured. In presence of the second separator, the sample is adjusted to the second separator temperature and pressure, where the oil and gas volumes are also measured. After testing all separator stages, the sample is flashed to stock tank conditions, where the volumes of stock tank oil and gas are monitored. The separator test volumetric data and the compositional analysis of the evolved gases from each pressure stage are reported. The separator test data were then used to adjust differential vaporization result to the surface conditions used in the separator test. Schematic representation of the multistage separator test is represented in **Figure 6**.

4. PVT correlations and software

Numerous correlations to calculate PVT properties for oils have been developed. The correlations are usually simple expressions (equations) that allow engineers to calculate the PVT properties from readily available inputs in case of absence of experimentally measured data. Correlations are generated from PVT Datasets associated with the particular geographical region. The most commonly known geographical correlations are Al-Marhoun [20] correlations for Saudi Arabian crudes; Standing [21] for California crudes; Petrosky [22] for Gulf of Mexico crudes; Hanafy et al. [23] for Egyptian crudes; and Omar and Todd [24] for Malaysian crudes. Some developed correlations use common oil samples of worldwide origin. The correlation is usually developed by fitting a predetermined form of an equation (or more) with the measured data and calculating the equation(s) parameters by use of multiple regression analysis. It is essential to note that the accuracy of correlation performance and applicability is associated with the range of data used in correlation development. PVT correlations developed as a function of PVT properties, or as groups of correlations developed from the same dataset for several PVT properties. **Table 3** gives a detailed survey on the published PVT correlations. Numerous software were developed for prediction of PVT phase behavior and physical properties such as PVTp, PVTsim, Eclipse E100, Eclipse E300, Petrel, and Ecrin. A detailed description of this software will be described elsewhere.

Correlation name	P_b	R_s	C_{ob}	B_{ob}	ρ_{ob}	μ_{ob}	C_{ou}	(GOR) _{STO}	B_{ou}	μ_{ou}	μ_{od}
Abdul-Majeed and Salman [25]				✓							
Abdul-Majeed et al. [26]						✓				✓	
Abu-Khamsim and Al-Marhoun [27]						✓					
Ahmed [28]			✓	✓	✓		✓				
Ahmed [29]									✓		
Al-Khafaji et al. [30]						✓				✓	✓
Al-Marhoun [31]	✓										
Al-Marhoun [20]		✓		✓							
Al-Marhoun [32]			✓	✓			✓		✓		
Al-Marhoun [33]				✓			✓				
Al-Marhoun [34]							✓				
Al-Mehaideb [35]	✓		✓	✓		✓				✓	
Al-Najjar et al. [36]	✓			✓							
Al-Shammasi [37]	✓	✓		✓							
Andrade [38]											✓
Frick [39]				✓							
Asgarpour et al. [40]		✓		✓							
Asgarpour et al. [40]	✓										
Beal [41]										✓	✓
Beggs and Robinson [42]						✓				✓	✓
Bennison [43]											✓
Bergman [44]						✓				✓	✓
Bergman and Sutton [45]						✓					
Sutton and Bergman [46]										✓	✓
Bolondarzadeh et al. [47]	✓			✓							
Calhoun [48]			✓								
Casey and Cronquist [49]		✓		✓							
Chew and Connally [50]			✓			✓					
De Ghetto et al. [51]	✓	✓	✓			✓				✓	✓
Dindoruk and Christman [52]	✓	✓	✓	✓		✓	✓			✓	✓
Doklah and Osman [53]	✓	✓		✓							
Elam [54]	✓			✓							
El-Banbi et al. [55]	✓			✓							
Elmabrouk et al. [56]	✓			✓				✓			
Elsharkawy and Alikhan [57]	✓	✓	✓	✓		✓					
Elsharkawy and Alikhan [58]										✓	✓
Elsharkawy and Gharbi [59]											✓
Farshad et al. [60]	✓	✓	✓	✓							
Fitzgerlad [61]											✓
Glaso [62]	✓	✓		✓		✓				✓	✓

Correlation name	P_b	R_s	C_{ob}	B_{ob}	ρ_{ob}	μ_{ob}	C_{ou}	(GOR) _{STO}	B_{ou}	μ_{ou}	μ_{od}
Hanafy et al. [23]	✓	✓		✓	✓	✓					
Hassan [63]	✓	✓									
Hemmati and Kharrat [64]	✓	✓		✓							
Hossain et al. [65]						✓				✓	✓
Ikiensikimama et al. [66]			✓			✓	✓			✓	✓
Ikiensikimama and Azubuike [67]	✓										
Ikiensikimama and Ogboja [68]	✓	✓		✓							
Karimnezhad et al. [69]	✓			✓							
Kartoatmdjo and Schmidt [70]	✓	✓	✓	✓		✓				✓	✓
Kartoatmdjo and Schmidt [71]	✓	✓	✓	✓		✓				✓	✓
Kaye [72]											✓
Khairy et al. [73]	✓			✓							
Khamehchi et al. [74]	✓	✓				✓					
Khan et al. [75]						✓				✓	✓
Khazam et al. [76]	✓	✓	✓	✓		✓				✓	✓
Knopp and Ramsey [77]		✓		✓							
Kouzel [78]										✓	
Labedi [79]		✓	✓	✓		✓	✓			✓	✓
Labedi [80]	✓	✓									
Labedi [81]	✓					✓				✓	✓
Lasater [82]	✓	✓									
Levitan and Murtha [83]	✓			✓							
Macary and El Batanony [84]	✓	✓		✓							
Mazandarani and Asghari [85]	✓	✓		✓							
McCain [14]	✓	✓	✓	✓	✓	✓				✓	✓
McCain et al. [86]			✓				✓				
Mehran and Movagharnejad [87]	✓			✓							
Moradi et al. [88]				✓							
Moradi et al. [89]	✓										
Mehran and Movagharnejad [87]	✓										
Naseri et al. [90]						✓				✓	✓
Naseri et al. [91]											✓
Ng and Egbogah [92]											✓
Obomanu and Okpobiri [93]	✓			✓							
Okeke and Sylvester [94]								✓			
Okoduwa and Ikiensikimama [95]	✓										
Omar and Todd [24]	✓			✓							
Osorio [96]						✓					
Ostermann and Owolabi [97]	✓			✓							
Owolabi [98]	✓			✓							

Correlation name	P_b	R_s	C_{ob}	B_{ob}	ρ_{ob}	μ_{ob}	C_{ou}	$(GOR)_{STO}$	B_{ou}	μ_{ou}	μ_{od}
Oyedeko and Ulaeto [99]											✓
Petrosky [22]	✓	✓	✓	✓		✓				✓	✓
Petrosky and Farshad [100]	✓	✓	✓	✓		✓				✓	✓
Petrosky and Farshad [101]						✓				✓	✓
Petrosky and Farshad [102]	✓	✓	✓	✓		✓				✓	✓
Rollins et al. [103]								✓			
Sattarina et al. [104]											✓
Spivey et al. [105]							✓				
Standing [21]	✓	✓	✓	✓	✓	✓				✓	✓
Standing [106]	✓	✓									
Standing [107]			✓	✓	✓	✓	✓			✓	✓
Sim [108]	✓	✓	✓			✓					
Sulaimon et al. [109]				✓							
Twu [110]										✓	
Oyedeko and Ulaeto [99]											✓
Valko and McCain [111]								✓			
Vasquez and Beggs [112]	✓	✓	✓	✓						✓	
Velarde et al. [113]	✓	✓									
Whitson and Brule [4]											✓

Table 3.
Summary of the published PVT correlations.

5. Conclusion

PVT studies are very critical and precious for reservoir engineers to monitor the phase behavior of petroleum fluids and generating material balance calculations. Traditionally, PVT experiments are carried out through high pressurized PVT-cell, but in case of unavailability of experimental facilities, we resort to empirically derived correlations. Several empirical correlations were published depending on geographical provinces. In this chapter, a brief description of the phase diagram for black and volatile oil was introduced as well as the importance of PVT properties in predicting petroleum fluids behavior. Then PVT physical parameters and its meanings were briefly illustrated and a summary of the input parameters in their predictions as well as a survey of the published correlations were provided. Moreover, a detailed description of the experimental PVT procedures and tests were illustrated to help engineers and analysts in conducting such tests.

Nomenclature

$(GOR)_{STO}$	stock-tank gas/oil ratio
μ_{ob}	saturated oil viscosity (at or below bubble point)
μ_{od}	dead oil viscosity correlations
μ_{ou}	under-saturated oil viscosity
bbl/STB	barrel/stock tank barrel

B_g	gas formation volume factor
B_o	oil formation volume factor, bbL/STB
B_{ob}	oil formation volume factor at the bubble point
B_{ou}	under-saturated oil formation volume factor
C_o	oil compressibility
C_{ob}	saturated oil compressibility (at or below bubble point)
C_{ou}	under-saturated oil compressibility (above bubble point)
GOR	producing gas-oil ratio
K_i	the equilibrium constant of component i in the recombined sample
N	number of separators
P_b	bubble point pressure
P_{ci}	critical pressure of component i in the recombined sample
PVT	pressure-volume-temperature
R_s	gas solubility
R_{sp}	separator GOR, scf/STB
R_{st}	GOR from the stock-tank, SCF/STB
Scf/STB	standard cubic foot/stock tank barrel
T_{bi}	true boiling point temperature of component i in the recombined sample
T_{ci}	the critical temperature of component i in the recombined sample
x_i	the mole fraction of component i in the separator oil
y_i	the mole fraction of component i in the separator gas
Z	gas compressibility factor
Z_f	gas compressibility factor measured at the field
Z_l	gas compressibility factor measured at PVT lab
γ_g	solution gas specific gravity
γ_{sep}	separator gas gravity
γ_{st}	gas gravity from the stock-tank
ρ_f	gas gravity measured at the field
ρ_l	gas gravity measured at PVT lab
ρ_{ob}	oil density at the bubble point

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