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PVT PROPERTIES OF BLACK CRUDE OIL-A REVIEW

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Abstract
Precise PVT studies and performance of phase-equilibria for petroleum reservoir fluid are essential for describing these fluids and appraising their volumetric behavior at several pressure stages. There are numerous laboratory studies that can be generated in a reservoir sample. The amount of available data regulates the number of tests that can be achieved in the laboratory. Generally, there are three laboratory tests that characterize hydrocarbon fluids, including primary study, constant mass depletion, and differential vaporization test. Generally, PVT properties determined either experimentally or calculated theoretically through published correlations. In this chapter, the author details different PVT laboratory tests utilized to distinguish the phase behavior of black oil.

Keywords: PVT Experiments; Black oil properties; and Petroleum reservoirs.

1. Introduction

PETROLEUM (an equivalent term is 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 phases 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 reservoirs considered one of the most precious reservoir fluids.it constitutes the majority of oil reservoirs and exists in every basin. An accurate description of the 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 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. However, correlations are approximations and may be useful only in regional geological provinces.

Crude oils cover a wide range in physical properties and chemical compositions and classified into black oils and near-critical or volatile-oils [2] depending on their phase behavior. The phase diagram of the two reservoir types is illustrated in Figures 1&2, while their physical properties 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 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 considered as lean gas for indus-trial applications [5]. While in volatile oils, it is closest to the critical temperature. Another important differentiation lies in the volume of evolved gas below the bubble point, which is much greater in volatile oil than that observed for black oils [6]. Another important factor is comprising Gas oil ratio and mole % of C_7^+, where GOR provided from field data, while mole % of C_7^+ provided from composition analysis. PVT properties for black oils are required in almost all reservoir, production and surface facilities calculations to manage, develop, and forecast oil field behavior [7], as well as maximizing economic profit.
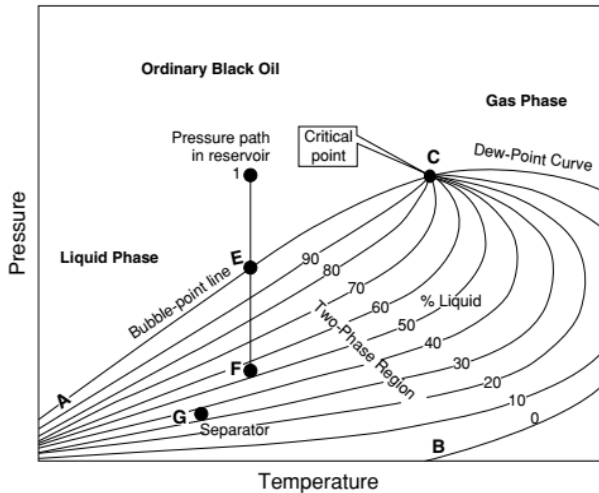

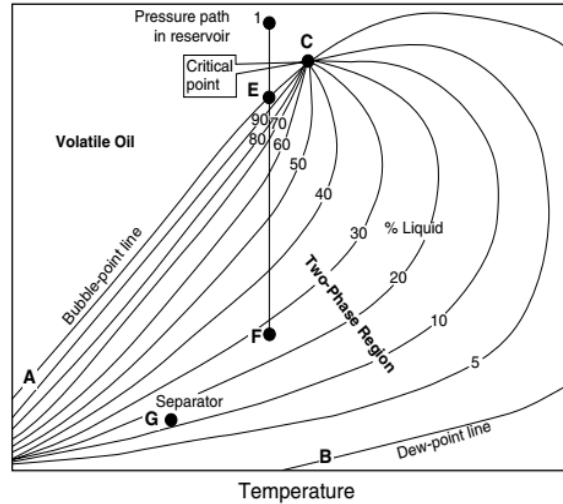Figure 1. Typical phase diagram for black oil[8]

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

Table 1. Criteria of black and volatile oil reservoirs

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_i)	~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 satu-rated-to highly saturated GOR oils)	......
β_o	< 2 rbbl/STB	> 2 rbbl/STB

PVT analysis utilized by reservoir engineers to distinguish the physical properties of reser-voir fluid and alterations in the volume and phase state occurs during oil production [10-11]. The phase envelope characterized by some physical criteria, including oil formation volume factor, saturation pressure , gas oil ratio, oil density, oil viscosity, and oil isothermal com-pressibility. This phase envelope may be drawn through experimental data points or via soft-ware 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 forecasts PVT criteria 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 that rely on the equation of states and their hybrids. In these models besides PVT parameters, other criteria 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 variation 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 implemented at reservoir temperature as a function of pressure. Once obtaining these parameters, it can be applied in empirical correlations to obtain the relative in situ amounts of oil and gas during the production life of the reservoir. These physical parameters include the following;

2.1. The crude oil API gravity

Crude oil density 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, gas ejected from the solution and formed 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 defined as the ratio of the oil density to water density at 60°F and atmospheric pressure by the following relation;

$$API = \frac{141.5}{\gamma o} - 131.5 \qquad \text{(eq. 1)}$$

2.2. Solution gas specific gravity

It is a dimensionless property represent 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;

$$\gamma g = \frac{\Sigma_{i=1}^{n} (R_{sep})_i (\gamma_{sep})_i + R_{st}\gamma_{st}}{\Sigma_{i=1}^{n} (R_{sep})_i + R_{st}} \qquad \text{(eq. 2)}$$

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].

$$Rs = \frac{(Vg)P,T}{(Vo)sc} \qquad \text{(eq. 3)}$$

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 a maximum value at saturation pressure. Below the bubble point pressure, gas evolves with pressure decline, and gas solubility decrease. Generally, the lighter the oil, the higher the gas solubility, therefore volatile oils often have 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 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 formed in the reservoir. Since gas mobility > oil mobility, the produced GOR increases with continual pressure depletion beneath the saturation pressure. Other PVT criteria 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 and bubble point pressure from the equations 4&5 respectively;

$$Co = -\frac{1}{dv}\frac{dv}{dp} \qquad \text{(eq. 4)}$$

$$Co = -\frac{1}{Bo}\left[\left(\frac{\partial Bo}{\partial P}\right)_T - Bg\left(\frac{\partial Rs}{\partial P}\right)_T\right] \qquad \text{(eq. 5)}$$

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 undesaturated 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;

$$Z = \frac{PV}{nRT} \qquad \text{(eq. 6)}$$

2.7. Oil formation volume factor

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

$$(Bo)res = \frac{(Vo)(p,T)res}{(Vo)sc} \qquad \text{(eq. 7)}$$

$$(Bo)sep = \frac{(Vo)(p,T)sep}{(Vo)sc} \qquad \text{(eq. 8)}$$

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 falling down from reservoir pressure to surface conditions, the following scenarios 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) determined from residual oil volume at 60°F at the end of differential liberation. The increase of B_o above bubble point pressure resort to oil expansion by pressure decline so the oil volume at P & T (the nominator in equation 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

Defined as the gas volume at the temperature and pressure of any stage below the bubble point, divided by the volume of the same gas at standard conditions through differential liberation, B_g can also be calculated from composition analysis as a function of Z-factor as stated in equation 10.

$$Bg = \frac{(Vg)P,T}{(Vg)sc} \qquad \text{(eq. 9)}$$

$$Bg = \frac{0.028269Z(T)R}{(P)psia} \qquad \text{(eq. 10)}$$

2.9. Crude oil viscosity

It is defined as the resistance of the fluid to flow, expressed in centipoise (cP). It is affected by 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 decreasing, owing to reduced friction between fluid layers, and reach to its minimal at the saturation pressure. With further pressure depletion, more and more gas escaped from the oil, so the oil becomes denser (i.e., more viscous) owing to the loss of lighter components. Practically oil viscosity measured by falling ball viscometer. Table 2 summarizes the applied inputs for some of the input physical parameters used to characterize black oil reservoirs.

Table 2. Major input parameters for PVT equations

Property		Input parameters
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}).
Crude oil gravity (API)		The specific gravity of the solution gas (γ_g); Oil specific gravity (γ_o).
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}).
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}).
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)
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).
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).
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}).

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 was heated to 200°F and stabilized in the single phase prior to the 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 is virtually represented for the reservoir.

A) Surface samples obtained from the 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.

B) Bottom hole sample:

Also, check of cylinders integrity during transportation and s**ampling 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 as follow;

i. 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. The 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 the 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.

ii. Composition analysis of stock-tank oil:

The compositions of paraffin's 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 meters in length and 0.25 mm internal diameter. Suitable sample capacity was injected into a split/splitless injector through a microsyringe according to both response and linear range of FID detector. Nitrogen (free oxygen) 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, solids (BS), and sulfur contents, in order to determine the oil quality.
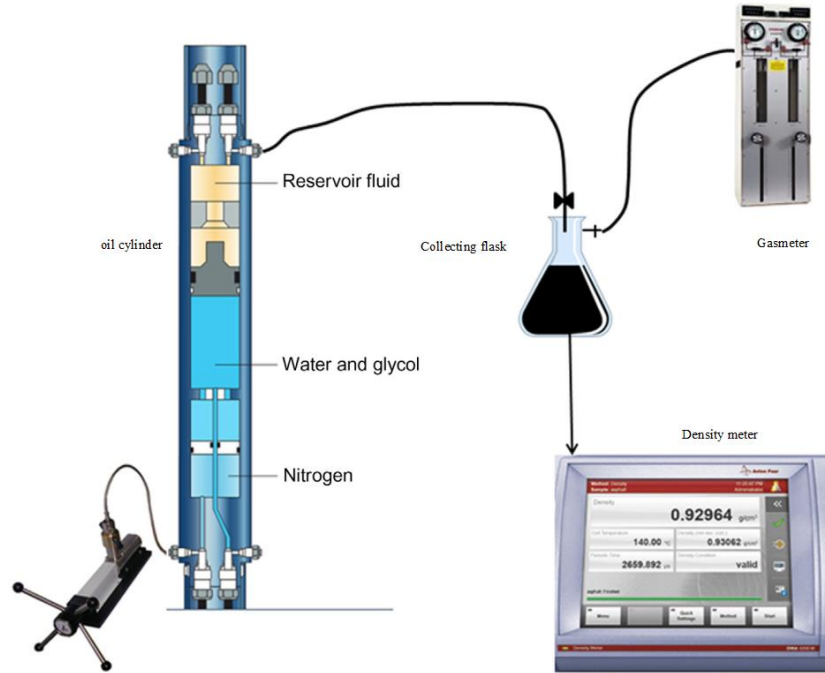

Figure 3. Diagram of the primary study steps

iii. Gas composition analysis:

The analysis of both separator gas and dissolved gas was determined according to ASTM 1945, using Clarus 500 PerkinElmer gas chromatograph online with the condensate cell utilizing four packed columns connected in series with a thermal conductivity detector and DP-1 capillary column matched with flame ionization detector. Helium was used as the carrier gas, and the oven isothermal temperature 100ºC 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 of three main assays; constant Mass depletion (CMD), Differential Liberation (DL), and separator test.

iv. 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.

v. Measurement of molecular weight

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

vi. 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)

$$\text{Corrected separator GOR} = (Field\ GOR * \frac{\rho f * Zf}{\rho l * Zl})^{0.5} \qquad \text{(eq. 11)}$$

$$Zf = \left(\frac{1}{fpv}\right)^{0.5} \qquad \text{(eq. 12)}$$

$$Adjusted\ Separator\ GOR\ =\ Corrected\ Separator\ GOR/Bo \quad \text{(eq. 13)}$$

vii. 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;
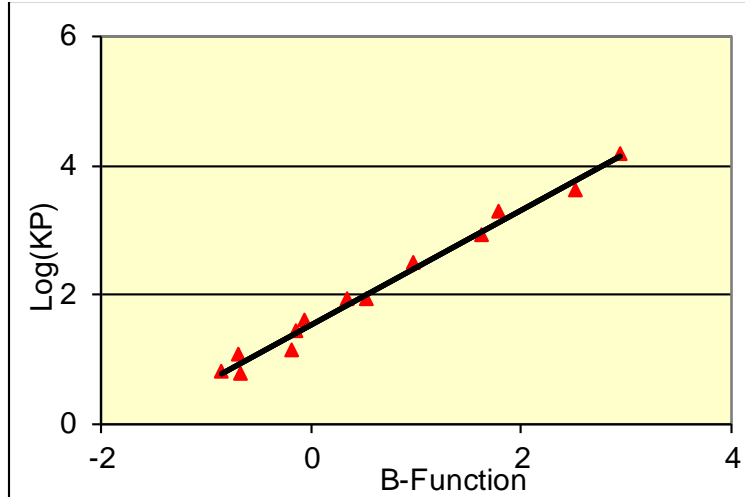

Figure 4. Hofmann QC- plot

where $Ki = \frac{yi}{xi}$ (eq. 14)

$Bi = log(Pci/14.7)/(1/Tbi - 1/Tci)$ (eq. 15)

viii. 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 a 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 °F). The flashed data were then checked using the 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, the pressure of the sample chamber is 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 knew as flash liberation, in which a set of volume measurements as a function of pressure at fixed reservoir temperature is 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 undersaturated 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 as 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 for both live and dead oil 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.
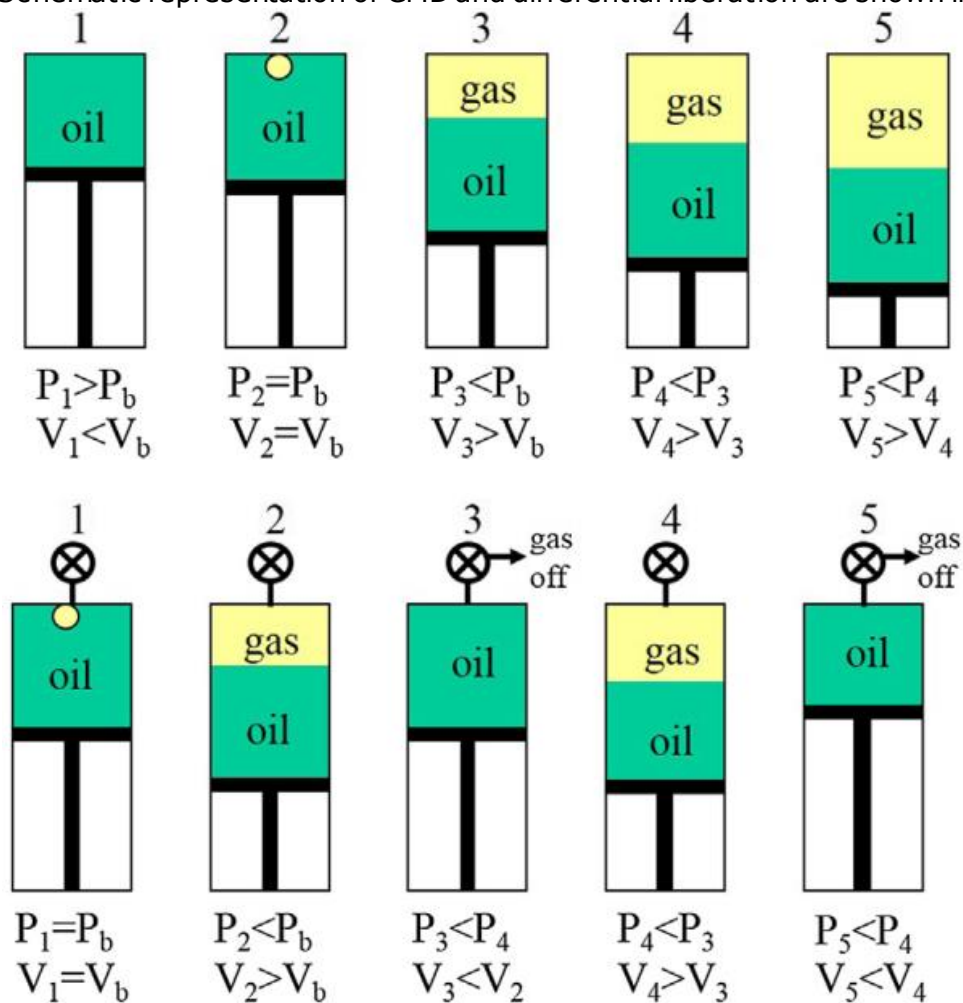
Figure 5. Schematic illustration of (a) Constant mass depletion; (b) Differential liberation [6]

3.6. Separator test

Separator tests 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 100cc 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 detected. In the presence of the second separator, the sample is adjusted to the second separator temperature and pressure, where the oil and gas volumes are also detected. 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 results in the surface conditions used in the separator test. The schematic representation of the multistage separator test is represented in Figure 6.
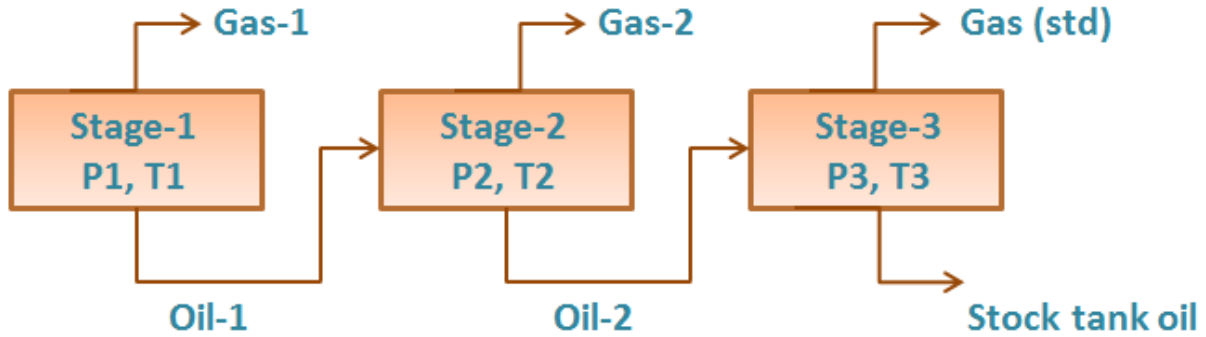

Figure 6. Multistage separator test

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 of the published PVT correlations. Numerous software 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.

Table 3 Summary of the published PVT correlations

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 (1988) [25]				✓							
Abdul-Majeed *et al.* (1990) [26]						✓				✓	
Abu-Khamsim and Al-Marhoun (1991) [27]						✓					
Ahmed (1989) [28]			✓	✓	✓		✓				
Ahmed (1992) [29]									✓		
Al-Khafaji *et al.* (1987) [30]						✓				✓	✓
Al-Marhoun (1985) [31]	✓										
Al-Marhoun (1988) [20]		✓		✓							

Correlation name	P_b	R_s	C_{ob}	B_{ob}	ρ_{ob}	μ_{ob}	C_{ou}	(GOR) STO	B_{ou}	μ_{ou}	μ_{od}
Al-Marhoun (1992) [32]			✓	✓			✓		✓		
Al-Marhoun (2003) [33]				✓			✓				
Al-Marhoun (2006) [34]							✓				
Al-Mehaideb (1997) [35]	✓		✓	✓		✓				✓	
Al-Najjar et al. (1988) [36]	✓			✓							
Al-Shammasi (1999) [37]	✓	✓		✓							
Andrade (1930) [38]											✓
Frick (1962) [39]				✓							
Asgarpour et al. (1989) [40]		✓		✓							
Beal (1946) [41]										✓	✓
Beggs and Robinson (1975) [42]						✓				✓	✓
Bennison (1998) [43]											✓
Bergman (2004) [44]						✓				✓	✓
Bergman (2007) [45]						✓					
Bergman and Sutton (2006) [46]										✓	✓
Bolondarzadeh et al. (2006) [47]	✓			✓							
Calhoun (1947) [48]			✓								
Casey and Cronquist (1992) [49]		✓		✓							
Chew and Connally (1959) [50]			✓			✓					
De Ghetto et al. (1995) [51]	✓	✓	✓			✓				✓	✓
Dindoruk and Christman (2001) [52]	✓	✓	✓	✓		✓	✓			✓	✓
Doklah and Osman (1992) [53]	✓	✓		✓							
Elam (1957) [54]	✓			✓							
El-Banbi et al. (2006) [55]	✓			✓							
Elmabrouk et al. (2010) [56]	✓			✓			✓				
Elsharkawy and Alikhan (1997) [57]	✓	✓	✓	✓		✓					
Elsharkawy and Alikhan (1999) [58]										✓	✓
Elsharkawy and Gharbi (2001) [59]											✓
Farshad et al. (1996) [60]	✓	✓	✓	✓							
Fitzgerlad (1994) [61]											✓
Glasso (1980) [62]	✓	✓		✓		✓				✓	✓
Hanafy et al. (1997) [23]	✓	✓		✓	✓	✓					
Hassan (2011) [63]	✓	✓									
Hemmati and Kharrat (2007) [64]	✓	✓		✓							
Hossain et al. (2005) [65]						✓				✓	✓
Ikiensikimama (2008) [66]			✓			✓	✓			✓	✓
Ikiensikimama (2012) [67]	✓										
Ikiensikimama and Ogboja (2009) [68]	✓	✓		✓							
Karimnezhad et al. (2014) [69]	✓			✓							
Kartoatmdjo and Schmidt (1991) [70]	✓	✓	✓	✓		✓				✓	✓
Kartoatmdjo and Schmidt (1994) [71]	✓	✓	✓	✓		✓				✓	✓
Kaye (1985) [72]											✓
Khairy et al. (1998) [73]	✓			✓							

Correlation name	Pb	Rs	Cob	Bob	ρob	μob	Cou	(GOR) STO	Bou	μou	μod
Khamehchi and Ebrahimian (2009) [74]	✓	✓				✓					
Khan et al. (1987) [75]						✓				✓	✓
Khazam et al. (2016) [76]	✓	✓	✓	✓		✓				✓	✓
Knopp and Ramsey (1960) [77]		✓		✓							
Kouzel et al. (1965) [78]										✓	
Labedi (1982) [79]		✓	✓	✓		✓	✓			✓	✓
Labedi (1990) [80]	✓	✓									
Labedi (1992) [81]	✓					✓				✓	✓
Lasater (1958) [82]	✓	✓									
Levitan and Murtha (1999) [83]	✓			✓							
Macary and El Batanony (1992) [84]	✓	✓		✓							
Mazandarani and Asghari (2007) [85]	✓	✓		✓							
McCain (1991) [14]	✓	✓	✓	✓	✓	✓				✓	✓
McCain et al. (1988) [86]			✓				✓				
Mehran et al. (2006) [87]	✓			✓							
Moradi et al. (2013) [88]				✓							
Moradi et al. (2010) [89]	✓										
Movagharnejad and Fasih (1999) [87]	✓										
Naseri et al. (2005) [90]						✓				✓	✓
Naseri et al. (2012) [91]											✓
Ng and Egbogah (1983) [92]											✓
Obomanu and Okpobiri (1987) [93]	✓			✓							
Okeke and Sylvester (2016) [94]								✓			
Okoduwa and Ikiensikimama (2010) [95]	✓										
Omar and Todd (1993) [24]	✓			✓							
Osorio (1990) [96]						✓					
Ostermann and Owolabi (1983) [97]	✓			✓							
Owolabi (1984) [98]	✓			✓							
Oyedeko and Ulaeto (2011) [99]											✓
Petrosky (1990) [22]	✓	✓	✓	✓		✓				✓	✓
Petrosky and Farshad (1993) [100]	✓	✓	✓	✓		✓				✓	✓
Petrosky and Farshad (1995) [101]						✓				✓	✓
Petrosky and Farshad (1998) [102]	✓	✓	✓	✓		✓				✓	✓
Rollins et al. (1990) [103]								✓			
Sattarina et al. (2007) [104]											✓
Spivey et al. (2007) [105]							✓				
Standing (1947) [21]	✓	✓	✓	✓	✓	✓				✓	✓
Standing (1951) [106]	✓	✓									
Standing (1981) [107]			✓	✓	✓	✓	✓			✓	✓
Steve (1993) [108]	✓	✓	✓			✓					
Sulaimon et al. (2014) [109]				✓							
Twu (1985) [110]										✓	
Ulaeto and Oyedeko (2011) [99]											✓

Correlation name	P_b	R_s	C_{ob}	B_{ob}	ρ_{ob}	μ_{ob}	C_{ou}	(GOR) STO	B_{ou}	μ_{ou}	μ_{od}
Valko and McCain (2003) [111]								✓			
Vasquez and Beggs (1980) [112]	✓	✓	✓	✓						✓	
Velarde *et al.* (1997) [113]	✓	✓									
Whitson and Brule (2000) [4]											✓

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 a 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*

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 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 fluid's 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 was provided. Moreover, a detailed description of the experimental PVT procedures and tests were illustrated to help engineers and analysts in conducting such tests.

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