

Validation of PVT Parameters in Saturated Black Oil Reservoir Using Standing Correlations

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Abstract

Pressure-Volume-Temperature (PVT) analysis of reservoir fluid is an important concept that provides some useful information on the properties of a reservoir with hydrocarbon in place. There is therefore the need to validate and where necessary correct PVT data at the minimal cost before application. This work was able to evaluate the PVT parameters of a saturated black oil reservoir in the Niger Delta area of Nigeria, validate and correct the data due to error from sampling stage using analytical method. The basic mathematical tools used in this work are standing correlations which are standard correlations in PVT analysis with satisfactory level of accuracy. The basic PVT parameters (R_{sp} , B_{ob} , and B_{od}) obtained from the experiment were corrected using analytical method. It was found that the PVT sample had less gas than the original reservoir fluid due to excessive drawdown or phenomenon of gas saturation (S_g). The original reservoir fluid had a bubble-point pressure of 101psig more than the bottomhole sample. Evaluation of PVT parameters before use in reservoir analysis has been proven to be of great importance to the reservoir engineer in the oil industry.

Keywords: Pressure-Volume-Temperature; Standard Correlation; Saturated Black Oil Reservoir

Introduction

The volumetric behaviour of reservoir fluid due to changes in temperature and pressure is influenced by the physical properties of the fluid such as composition, density, viscosity, etc. This behaviour is easily understood through analysis of results obtained from either controlled PVT (Pressure-Volume-Temperature) experiments on crude oil samples, or field test (or induction data). Observation has shown that PVT parameters measured from bottom-hole samples taken from saturated reservoir do not always represent the true condition in the reservoir due to the effects of excessive drawdown pressure (that is, the difference between the bottom-hole flowing pressure and the initial reservoir pressure), gas saturation, etc (Dake 1978). It is therefore becoming a normal practice for PVT data on saturated black oil reservoir to be evaluated before use. The evaluation procedure involves using the gas-oil contact (GOC) to estimate the bubble-point pressure of the oil; where the data is found to be wrong due to the drawdown pressure, the PVT parameters have to be re-determined starting from the sampling stage to the data –report stage or validated and corrected using standard correlations. There are five types of reservoir fluids: Black oil, volatile oil, retrograde gas, wet gas and dry gas. It is important that the field engineer determines the type of fluid in the early life of a reservoir so as to enable him or her decide the method of sampling, the type and size of surface equipment to be used, the causational procedures for determining oil and gas in a place, the techniques of predicting oil and gas reserves, the plan of depletion, and selection of enhanced recovery method. Three properties that are readily available as rules of thumb for identifying each of the five types of reservoir fluids are the initial producing gas-oil ratio, API gravity of the stock-

tank liquid, and the colour of the stock-tank liquid, but the initial producing gas-oil ratio is by far the most important indicator of the type of fluid (Mc Cain, 1990). Note that stock-tank-oil means dead oil (i.e oil with zero gas at atmospheric pressure) corrected to 60°F. The name black-oil is misnomer since the colour of this type of oil is not always black. This type of reservoir fluid has also been called low-shrinkage crude oil or ordinary oil (Mc Cain, 1990).

Black oils consist of a wide variety of chemical species including large, heavy, non-volatile molecules. The phase diagram predictably covers a wide temperature range. Black oils exhibit initial producing gas-oil ratios of above 2000scf/stb (standard cubic feet per stock-tank barrel) or less. Producing gas-oil ratio will increase during production. When reservoir pressure falls below the bubble-point pressure of the oil, the stock-tank oil usually will have gravity below 45° API which decreases slightly with time until late in the life of the reservoir when it will increase (Mc Cain, 1990). The stock-tank oil is very dark, often black, indicating the presence of heavy hydrocarbons, sometimes with a green or brown cast. Laboratory analysis will indicate an initial oil formation-volume factor of 2.0 reservoir barrels per stock-tank barrels (res bbl/stb) or less. Reservoir engineering requires knowledge of how much gas is in the oil at the reservoir conditions, and how much of the oil would shrink if it were brought to the surface. The three basic PVT properties used to serve this purpose are solution gas-oil ratio, oil formation-volume factor and gas formation-volume factor; other PVT parameters considered in this work include viscosity and compressibility factor (Drake, 1978). Standing (1947), experimented the PVT behavior of 22 different crude oil/ natural systems and presented correlations for solution gas-oil ratio, formation volume factor, and bubble point pressure, obtained from 105 data points as functions of gas gravity, oil gravity, pressure and temperature. If a given PVT data is found to be wrong through the normal evaluation procedure, then we need to re-determine the PVT parameters starting from the sampling stage to the data report stage which is very expensive. This procedure is very cumbersome and expensive, hence the need for an alternative means of validating and correcting such wrong PVT data. The aim of this work is to determine PVT parameters experimentally from bottom-hole samples collected from saturated black oil reservoir as well as to determine the accuracy of the PVT experiment by comparing the corrected data with the original data obtained from oil samples of the same well.

Materials and Methods

Most of the experiments and measurements carried out in this work are carried out using RUSKA (Note; RUSKA is an American Engineering firm that manufactures high precision instrument for measuring reservoir fluid properties). RUSKA research precision instruments when properly calibrated, can measure fluid properties to +0.01 percent accuracy. The three main parameters measured are pressure, volume and temperature of the reservoir fluid. The RUSKA dead weight gauge or the Heise gauge is used to measure pressure, RUSKA gasometer is used to measure gas volume, RUSKA visual liquid phase PVT cell is used to carry out PVT experiment, pod distillation column is used for low, temperature distillation of the reservoir fluid, while RUSKA digital thermometer is used to measure reservoir fluid temperature. Other equipment and accessories used in the analysis are viscometer, barometer, mercury pumps, gas chromatography, and low and high pressure gauges.

The key materials for analysis used in this work are; sampling of reservoir fluid and the different sampling techniques of the reservoir fluid. In this work four major experiments are carried out which includes;

- ✓ Viscosity test
- ✓ Constant composition expansion (CCE)

- ✓ Differential liberation expansion (DLE)
- ✓ Multistage-separator test

Viscosity Test

The viscosity test was carried out using viscometer. If the oil viscosity is desired at reservoir pressure and temperature, it is necessary to use a high-pressure rolling-ball viscometer. This instrument measures the time required for a precision steel ball to roll a given distance in a tube filled with oil. The time of travel is converted to viscosity by means of a calibration curve for the instrument. The clearance between the ball and tube can be changed by changing the ball diameter. The lower the fluid viscosity, the smaller the clearance used. The procedures used in carrying out a successful viscosity test in this work are summarized as follows;

- 1) The viscosity was vacuum for at least one hour to remove air.
- 2) The temperature of the viscometer was set to the reservoir temperature and the viscometer was filled with the sample at a pressure above the reservoir pressure, also the housing was rock with the barrel seal open, thus enabling the ball to roll in the barrel, thereby stirring the liquid and ensuring thermal equilibrium and accurate pressure adjustment.
- 3) The housing was held in its inverted position so that the ball comes to and against the barrel seal, after which the housing was turn to an angle 70° position and the barrel seal shut and the ball was released to drop through the fluid in the barrel and the time of fall was noted on the indicated and the whole step was repeated for angles 45° and 23° .
- 4) The pressure was dropped to the next lower pressure and the fall time readings were taken respectively, after which the outlet valve was shut when rocking the barrel at the bubble-point pressure and below it.
- 5) Step 3 was repeated for each pressure point below bubble-point down to atmospheric pressure.
- 6) The fall time was then converted to viscosity values at the various pressure points by means of calibration curves for the instrument.

Constant Composition Expansion (CCE)

The CCE experiment is used to determine bubble-point pressure, undersaturated oil density, isothermal oil compressibility and two-phase volumetric behaviour at pressure below the bubble-point pressure at reservoir temperature. A RUSKA visual PVT cell was filled with a known mass of reservoir fluid. The sample was initially brought to a condition somewhat above initial reservoir pressure ensuring that the fluid is single-phase. The pressure was then decreased in steps by reducing the mercury level in the cell to attain equilibrium and the corresponding volume of the oil at each step was recorded after sufficient agitation. To prevent the phenomenon of supersaturation or metal-stable equilibrium where a mixture remains as a single-phase even though it is below the bubble-point pressure, the stepwise decrease of pressure was continued until sufficient pressure-volume were taken above and below the estimated bubble point obtained from the quality check (Standing, 1997).

Differential Liberation Expansion (DLE)

This experiment is designed to approximate the depletion process of an oil reservoir and thereby providing suitable PVT data to calculate reservoir performance (Moses, 1986). A PVT cell was filled with the reservoir oil, which was brought to a single-phase (ie above reservoir pressure) at reservoir temperature. The pressure was decreased until the fluid reaches its bubble-point and the oil volume at this point, V_{ob} was recorded. Since the initial mass was known, the bubble-point density of the oil (ρ_{ob}) was calculated. The pressure was decreased below the bubble-point in steps, and at each point, the cell was agitated until equilibrium was reached and the gas was removed at constant pressure before proceeding to the next step. The

volume (ΔV_g), number of moles (Δn_g) and the specific gravity ($\Delta \gamma_g$), of the removed gas as well as the volume of the remaining oil (V_o) was measured at each pressure point. This procedure was repeated for not less than seven steps until it gets to atmospheric pressure where the residual-oil volume (V_{or}) and specific gravity (γ_{or}) were measured. Other properties that were calculated for each step (or stage) based on the above measured data were differential solution gas-oil ratio (R_{osd}), differential oil formation volume factor (B_{od}), oil density (ρ_o), and gas deviation factor (Z), for stage K , these properties were determined as follows (Moses, 1986);

$$(R_{sd})_k = \frac{\sum_{j=1}^k 379(\Delta n_g)_j}{V_{or}} \quad (1)$$

$$(B_{od})_k = \frac{V_R}{V_{or}} \quad (2)$$

$$(\rho_{ob})_k = \frac{350\gamma_o + \sum_{j=1}^k 0.0764(R_{sd})_j(\gamma_g)_j}{5.6158(B_{od})_k} \quad (3)$$

$$(Z)_k = \left(\frac{1}{RT}\right) \left(\frac{\rho \Delta V_g}{\Delta n_g}\right)_k \quad (4)$$

Note that gas-oil ratio (R_s) and formation-volume factor (B_o) was calculated directly from results of the DLE experiment. For stock tank conditions using (Curtis and Michael, 2000) equation as follows,

$$R_s = (R_{sb} - R_{sd}) \left(\frac{B_{ob}}{B_{odb}}\right) \quad (5)$$

$$B_o = B_{od} \left(\frac{B_{ob}}{B_{odb}}\right) \quad (6)$$

Multistage-Separator Test

The multistage-separator test is performed on oil sample primarily to provide a basis for converting differential-liberation data from residual-oil to a stock-tank-oil basis. Occasionally, several separator tests are run to help choose separator conditions that maximize stock-oil-oil production. Usually, two or three stages of separation are used, with the last stage at atmospheric pressure and near-ambient temperature (60 to 80°F).

Initially, the reservoir sample was at saturation conditions and the volume measured (V_{ob}). The sample was then brought to the pressure and temperature of the first-stage separator. All the gas was removed, and the oil volume at the separator stage (V_{osp}) was noted together with the volume of the removed gas (ΔV_g). The number of moles of the removed gas (Δn_g), and the specific gravity of the removed gas (γ_g). The oil remaining after gas removal was brought to the conditions of the next separator stage. The gas was removed again and quantified by moles and specific gravity. The oil volume was noted, and the process was repeated until stock-tank conditions were reached. Final oil volume (V_o), and specific gravity (γ_o) were measured at 60°F. The total gas-oil ratio (GOR) was calculated by adding the stock-tank oil based GORs for each separator stage as

$$R_s = \sum_{k=1}^{Nsp} (\Delta R_s)_k \quad (7)$$

Where Nsp = number of stages in the multi-stage separator test, and ΔR_s is the stock-tank oil based GOR for each stage of the multi-stage separator test. From (Curtis and Michael 2000) equation for solution gas-oil ratios;

$$R_{sp} = \frac{V_g}{V_{osp}} \quad (8)$$

$$R_s = \frac{V_g}{V_{osp}} \quad (9)$$

Dividing equation (8) by (9) gives the formation volume factor for separator oil (B_{osp}) as

$$B_{osp} = \frac{R_s}{R_{sp}} \quad (10)$$

The average gas gravity for all the k-stage in the multistage separator test was calculated as

$$\gamma_g = \frac{\sum_{k=1}^{N_{sp}} (\gamma_g)_k (\Delta R_s)_k}{\sum_{k=1}^{N_{sp}} (\Delta R_s)_k} \quad (11)$$

The reservoir and well characteristics used in this work are as shown in table 1.0 below:

Table 1: Reservoir and well characteristics parameters

1	Producing zone	5706-5726ft MD (5627-5647ft SS)
2	Initial static pressure	2560psig at 5700ft SS
3	Reservoir temperature	186°F
4	Primary gas cap	Yes
5	Tubing size	3 $\frac{1}{2}$ '' OD
6	Total depth	6281ft MD (5619ft SS)
7	Well status	Producing
8	Choke size	(16/64)''
9	Sampling depth	5698ft MD (5619ft SS)
10	Flowing bottomhole pressure	2424psig at sampling depth
11	Temperature at sampling depth	186°F
12	Normal producing rate	3500BOPD

Samples Received at the Laboratory

Two samples were received from the laboratory, which includes; Cylinder number RFL02: Bottomhole sample 1 and Cylinder number RFL17: Bottomhole sample 2. A quality check was carried out to ensure that the sample collected was a representative of the reservoir fluid; i.e. no gas is lost in transit or it has not 'flashes' in transit. This experiment was carried out at room temperature of the laboratory which was 18°F to obtain the bubble-point pressure of the reservoir fluid, and the sample with the highest bubble-point pressure which in most cases is close to the separator pressure was chosen for subsequent experiments in this work. Table 2 in Appendix A1 shows the pressures and the corresponding volumes of mercury (i.e. pump reading) in the experiment for bottomhole sample 1, while those of bottomhole sample 2 are shown in table 3 in Appendix A1. The relationship between parameters of tables 2 and tables 3 are shown diagrammatically in figures 1 and figures 2 below respectively.

Results and Discussion

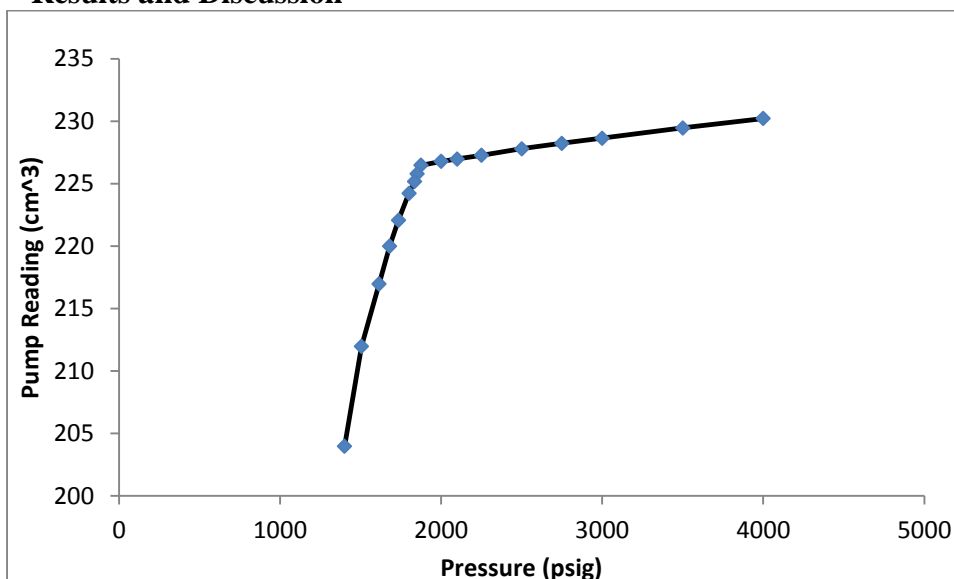


Fig.1: Plot of pump reading against pressure at 18°F (bottomhole sample 1)

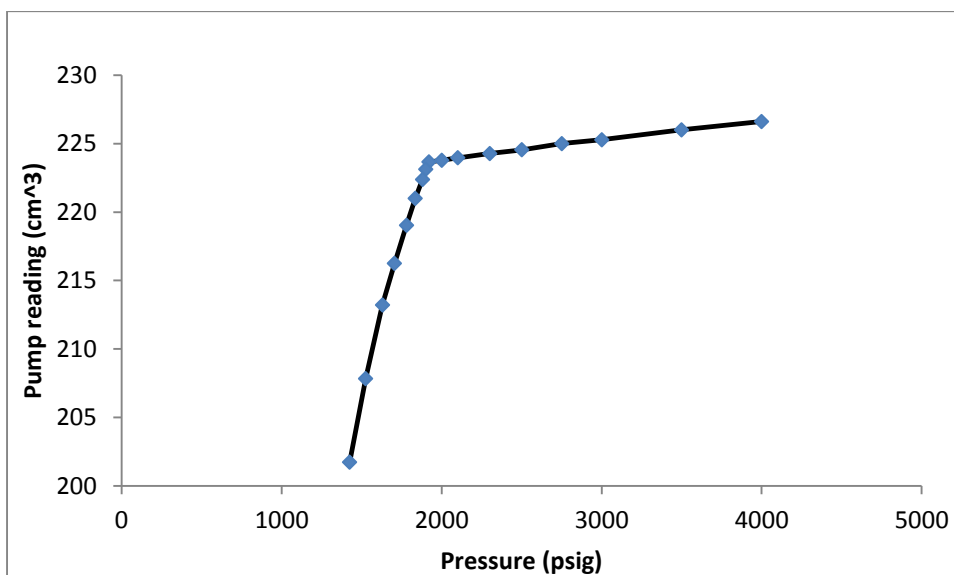


Fig.2: Plot of pump reading against pressure at 18°F (bottomhole sample 2)

From figure 1 and figure 2, the bubble-point pressure corresponds to the point where there is a sudden change in the trend of the curve which is about 1875psig for sample1 at 18°F, and about 1920psig for sample 2 at the same temperature. Thus sample 2 with the higher bubble-point pressure was chosen for the experiments conducted in this work as presented below.

Constant Mass or Constant Composition Expansion

This experiment was carried out at the reservoir temperature using sample 2 and the results obtained were as shown in table 4 in appendix A1. The obtained result was represented graphically as shown below in Figure 3.

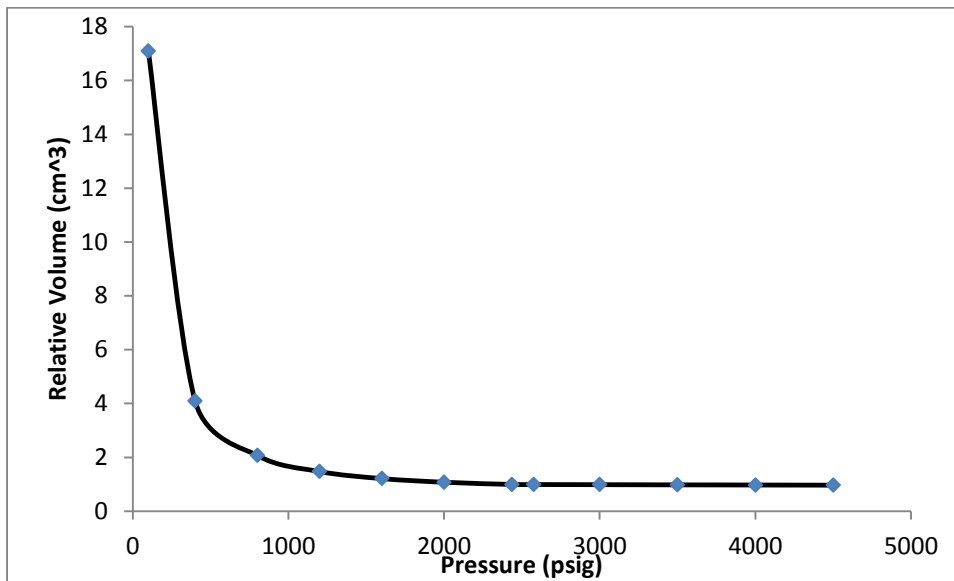


Fig.3: Plot of relative volume against pressure.

Figure 3 was used to estimate the true bubble point pressure P_{ob} , of the reservoir fluid, which for reservoir fluid sample 2 at the bottom-hole temperature of 186°F is about 2420psig. The true bubble-point pressure P_{ob} , was estimated as the lower limit of the horizontal-linear section of the curve.

Differential-Liberation Expansion

This experiment was used to determine the formation-volume factor (B_{ob}), gas deviation factor (Z), solution gas-oil ratio (R_{sd}), and liberated gas-oil ratio. Table 5 in appendix A1 showed the results of this experiment performed on bottom-hole sample 2. The obtained results were plotted graphically as shown in Figure 4 and Figure 5.

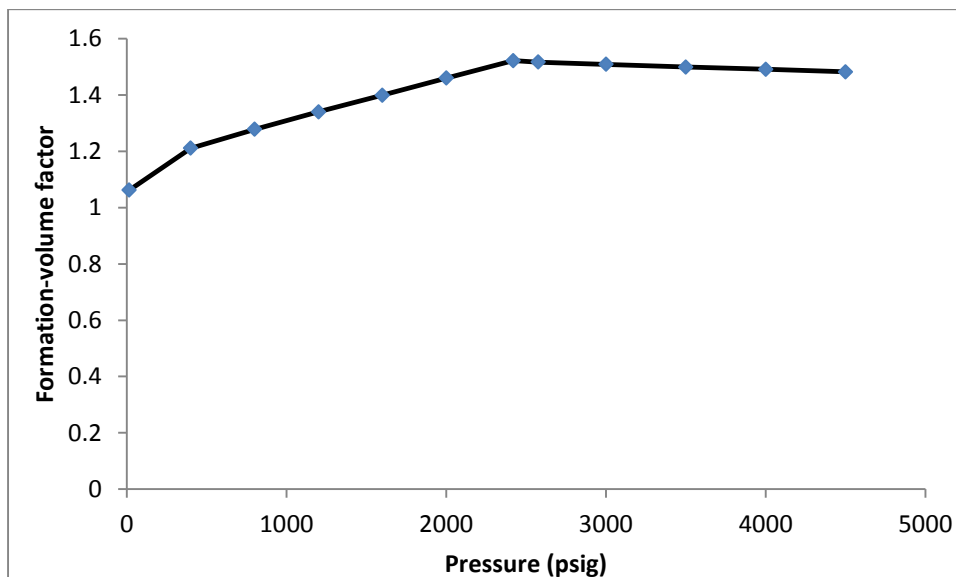


Fig.4: Plot of formation-volume factor against pressure at reservoir condition

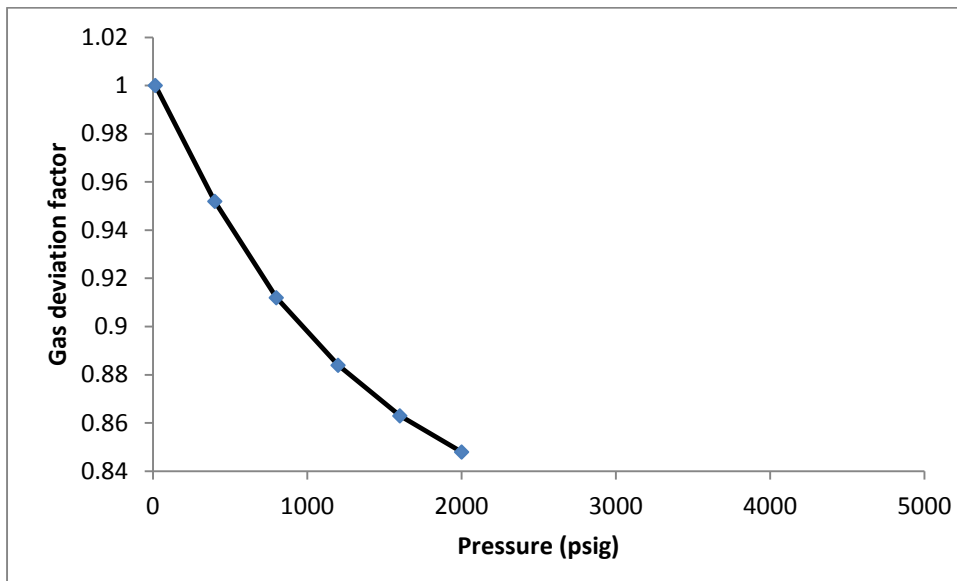


Fig.5: Plot of gas-deviation factor against pressure at reservoir condition.

Multistage-Separator Test

The results of this test performed on bottom-hole sample 2 are presented in table 6 in Appendix A1. Figures 6—7 showed the corresponding plots from which R_{sp} , B_{ob} , $^{\circ}API$, and γ_g can be estimated at any given pressure.

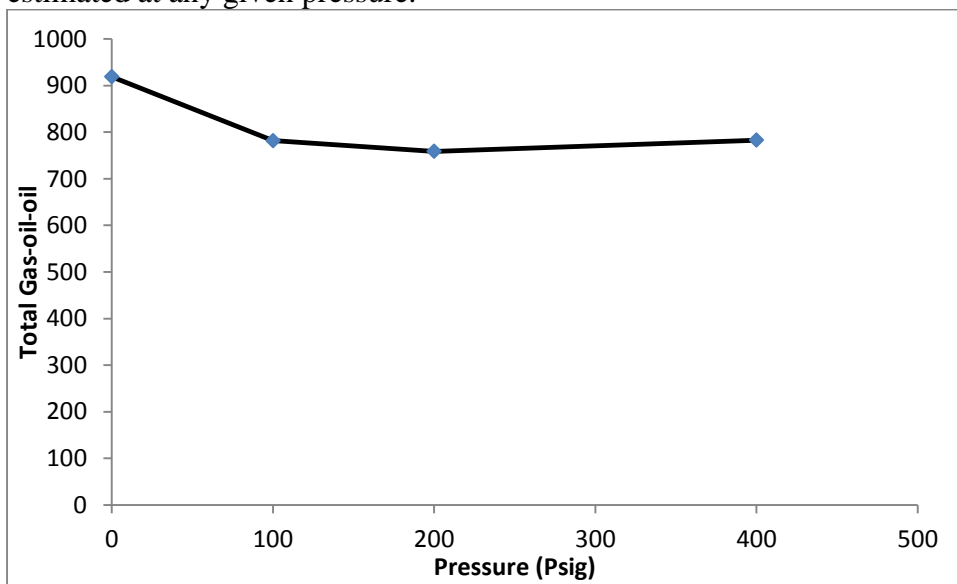


Fig.7: Plot of total gas-oil ratio against pressure at separator condition

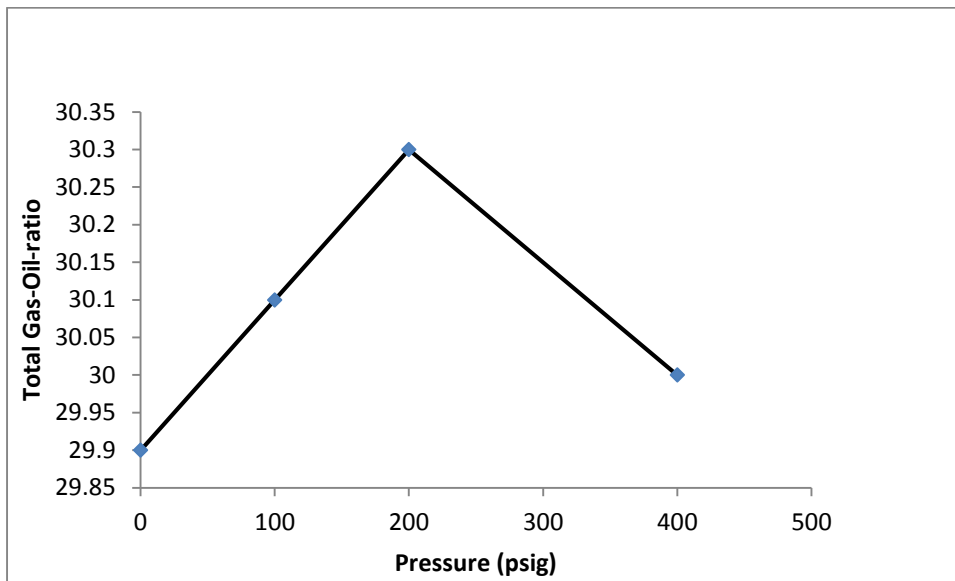


Fig. 7: Plot of oil gravity against pressure at separator condition

The separator pressure corresponding to the least solution gas-oil ratio (GOR), the highest API oil gravity is chosen as the optimum separator pressure (McCain, 1990). It may be seen that from figures 6-7 that the optimum separator pressure is about 200psig.

Validation of PVT Data

The PVT data obtained so far in the various experiments needed to be validated to ensure that there are no errors. The validation was done through pressure gradients obtained from the differential-liberation expansion experiment and multi-stage separator test. If the pressure gradients obtained from these two experiments are approximately equal, then the PVT results obtained are correct, but incorrect if the pressures gradients differ significantly.

Correction of PVT Parameters

There is every need to correct the PVT parameters for the experiments carried out since the bottomhole sample had less gas than the original reservoir fluid and this is due to excessive drawdown which may have resulted in free-gas production into the wellbore and its segregation past the sampler, or due to buildup of gas saturation which is less than the critical gas saturation and resulting to oil with reduced gas in solution. Based on this, the basic PVT parameters (R_{sp} , B_{ob} , and B_{od}) obtained from the experiments are not representative of the reservoir fluid due to error from sampling.

At the sampling depth of 5619ft SS, the flowing bottomhole pressure is 2424psig which is close to laboratory P_{ob} of 2420psig but about 100psig less than the actual P_{ob} . The separator flash data at separator pressure of 200psig obtained above are $\bar{Y}_g = 0.8651$, $Y_{or} = 0.8262$ (39.8° API), $R_{sp} = 759$ scf/stb and $T = 186^\circ\text{F}$. $Y_{or} = 0.8262$ (39.8° API), gives $R_{sp} = 833$ scf/stb. From the above, we calculate

$$\frac{\Delta R_{sp}}{\Delta P} = \frac{833 - 759}{2536 - 2359} = 0.42 \text{ scf}/(\text{psia})(\text{stb})$$

Thus the laboratory P_{ob} of 2420psia (2435psig) when raised to 2521psia (2536psig) would require additional GOR equal to give; Actual $R_{sp} = 759 + 42 = 801$ scf/stb. Similarly, the separator flash data at separator pressure of 200psig obtained above are $R_{sp} = 759$ scf/stb, $B_{osp} = 1.441$, $T = 186^\circ\text{F}$, $Y_{or} = 0.8262$ (39.8° API), and $\bar{Y}_g = 0.8651$ gives B_{ob} (Standing

correlation) = 1.484. Therefore Corrected B_{osp} (lab) = $B_{osp} + (1.484-1.459) = 1.441+0.025=1.466$

From the PVT report data in table 5 and 6, we find

$$\frac{B_{osp\text{ at } 200\text{psig}}}{B_{od\text{ at } 2420\text{psig}}} = \frac{1.441}{1.522} = 0.9468$$

Which may also be written as; $\frac{\text{Corrected } B_{osp}\text{ (at } 200\text{psig)}}{\text{Corrected } B_{od}\text{ (at } 2420\text{psig)}} = 0.9468$

$$\begin{aligned} \text{Corrected } B_{od}\text{ (at } 2420\text{psig)} &= \text{corrected } B_{osp}\text{ (at } 200\text{psig lab)} / 0.9468 \\ &= 1.466 / 0.9468 = 1.548 \end{aligned}$$

Conclusion

Evaluation of PVT parameters before use in reservoir analysis has been proven to be of great importance to the reservoir engineer in the oil industry. In the event of incorrect data on evaluation, the option of re-determination of PVT parameters from the sampling stage is uneconomical and time consuming. Hence the beauty of this work in applying standard correlations like standing correlations to validate and correct PVT parameters with high level of accuracy. It was found that the PVT sample had less gas than the original reservoir fluid due to excessive drawdown or phenomenon of gas saturation (S_g). The original reservoir fluid had a bubble-point pressure of 101psig more than the bottomhole sample. The basic PVT parameters (R_{sp} , B_{ob} , and B_{od}) obtained from the experiment were corrected using analytical method.

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APPENDIX A1

Table 2: corresponding pressures and pump readings of reservoir fluid (bottom hole sample 1) at 80°F

Pressure (psig)	Pump Reading (cm^3)
4000	230.220
3500	229.46
3000	228.640
2750	228.230
2500	227.790
2250	227.270
2100	226.970
2000	226.780
1875	226.470

Table 3: corresponding pressures and pump readings of reservoir fluid (bottom hole sample 2) at 80°F

Pressure (psig)	Pump Reading (cm^3)
4000	226.620
3500	226.010
3000	225.290
2750	225.010
2500	224.550
2300	224.280
2100	223.970
2000	223.790
1920	223.660

Table 4: Measured parameters of reservoir fluid at 186°F

Pressure (psig)	Relative Volume (V/V_{sat})	Y-Function $\frac{P_{sat}-P}{P((V/V_{sat})^{-1})}$	Liquid Viscosity (cp)	Phase
4500	0.9730		0.5400	
4000	0.9794		0.5200	
3500	0.9851		0.5000	
3000	0.9916		0.5000	
2575	0.9964		0.4800	
2435	1.0000		0.4630	
2000	1.0820	2.6530	0.4600	
1600	1.2174	2.4000	0.5000	
1200	1.4796	2.1460	0.5600	
800	2.0796	1.8930	0.6300	

Table 5: Multistage-separator test of reservoir fluid at 160°F

Pressure (psig)	Separator gas oil ratio (scf/stb)	Stock tank oil ratio (scf/stb)	Total gas oil ratio (scf/stb) R_{sp}	Formation volume factor B_{osp}	STO °API	Separator gas gravity (Y_{gsp})	Stock tank gas gravity
400	551	232	783	1.456	30.0	0.698	1.306
200	621	138	759	1.441	30.3	0.744	1.410
100	702	80	782	1.449	30.1	0.808	1.456
0	919	0	919	1.545	29.9	0.908	-