

PVT Analysis Reports of Akpet GT9 and GT12 Reservoirs

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Abstract: The estimation of the volume initial in place and the future performance prediction of hydrocarbon reservoir is associated with uncertainties in the geologic, petrophysical, PVT properties and production data. It is therefore important to accurately characterize the reservoir fluid properties to successfully simulate the reservoir and size of facilities. To accurately describe these properties, the ideal process is to sample the reservoir fluid and perform laboratory studies on the fluid samples. This study is carried out to evaluate the PVT properties of Akpet GT9 and GT12 reservoirs to determine parameters for oil in place evaluation, understand fluids behaviour during production and numerical simulations at the field scale. The PVT data was validated with Buckley and material balance plot and performed composition analysis for the reservoir fluids composition up to C11+ or C20+ and physical recombination for field gas-oil ratio (GOR) correction to ensure that the fluid sample used in the PVT analyses is representative.

Keywords: Dew Point Temperature, Gas Condensate, Black Oil, PVT Properties, Fluid Sampling, PVT Experiments

1. Introduction

PVT analysis is the study of the behaviour of vapour and liquid in petroleum reservoirs as a function of Pressure, volume, temperature in terms of phase behavior and composition. It plays a key role in calculating reserves as well as identification of reservoir characteristics. Thus, to appropriately estimate the reservoir pressure and saturation changes as fluid is produced throughout the reservoir requires a precise description of the reservoir fluid properties. To accurately describe these properties, the ideal process is to sample the reservoir fluid and perform laboratory studies on the fluid samples. In the early stages of a well it can be difficult or economically impractical to obtain reliable measurements. Fluid samples, if available, can be subjected to pressure-volume-temperature analyses to determine their properties, but samples are often suspected and PVT analyses usually apply only at reservoir temperature (S. S. Ikiensikimama and T. Egbe, 2006).

Method of sampling will depend on the nature of reservoir fluid- oil or gas and well completion and surface facilities. Basically there are two techniques for fluid sampling which are bottom hole sampling and surface sampling via drill stem

test (DST) and wireline formation tester (WFT) tool. The tools are classified based on lifetime of Well during which they are used. At early time during drilling, DST is used such as multiflow evaluator, annulus pressure responsive and pressure control test system while at the late time after the well is completed; WFT such as modular dynamic formation tester (MDT), formation integrity test (FIT) and repeat formation tester (RFT) is used.

The estimation of reserves and the design of the best depletion strategy are feasible only when realistic and reasonably accurate values of reservoir fluid properties are available (S. S. Ikiensikimama, 2008). In the absence of experimental analysis, empirical correlations or models can be used to estimate reservoir fluid properties. A variety of methods have been developed and published in the literature over the years that produce varying degrees of success depending upon the application such as Petrosky and Fashad (1993), Standing (1947), Ikiensikimama et al (2008) and Glaso (1980) etc.

All reservoir engineering calculations require PVT data. Amount of the data required depends on the choice the separation process, surface separation optimization, Reserves estimate, reservoir simulation and material balance

calculations, pressure transient testing, flow-line, wellbore hydraulics calculations, flow assurance, anticipated potential operating or environment problems and production allocation. To accurately determine the exact nature of a reservoir fluid is a challenge that calls for sampling and laboratory study with some factors affecting the reservoir fluid data such as leakage during Transport, calibration, vertical and lateral variation in fluid properties, sample size, mixture of fluid, recombination ratio, and stability of flow rate, temperature and pressure.

2. Reservoir Fluid Sampling

Basically, the sampling of reservoir fluid can be carried either at the subsurface or at the surface (wellhead/separator) and sometimes it is sampled at the production line for one phase flow which is rarely done. Figure 1 present a schematic

of reservoir fluid sampling at well site and laboratory analysis. Generally, reservoir fluid sampled at the surface are frequently collected at the gas and liquid separator which are then recombined to obtain a well stream fluid for full PVT analysis in a ratio that corresponds to the relative amounts of gas and liquid produced as the reservoir fluid travels up through the wellbore and on through the surface separation facilities. To successfully achieve this, we must have a good precision of the measured flow rate, stabilized well production or stable gas/oil ratio (GOR), oil and gas sampling realized almost simultaneously and absence of solid like wax.

In the recombination of fluid to obtain the reservoir fluid representative, pressure and temperature in the separator, gas and oil flow rate at the separator (orifice meter), gas density and compressibility factor for the gas measurement flow rate and oil tank flow rate (shrinkage) are essential data.

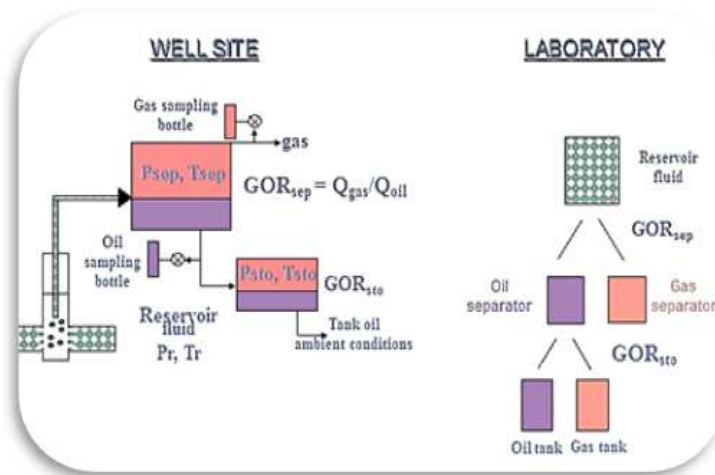


Figure 1. Well site fluid sampling.

Jeff et al, 1993 stated in their work on reservoir fluid sampling and recombination techniques for laboratory experiments that if the reservoir is highly undersaturated with a bubble point pressure that is actually lower than the wellhead pressure, wellhead samples may provide fluids that are nearly equivalent to subsurface samples. However, in general, wellhead samples will not directly provide representative reservoir fluids without altering the gas phase to achieve the correct reservoir fluid. For undersaturated reservoirs, the recombination of surface separator samples will usually result in a representative reservoir fluid provided that the well is producing at a stabilized gas-oil ratio (GOR). For undersaturated reservoirs where the producing GOR is not stable then the possibility exists that the bottom hole flowing pressure (BHFP) may actually be lower than the saturation pressure of the fluid. In this situation, solution gas may be liberated in the near wellbore area which then must first achieve critical gas saturation before it will flow into the wellbore and on to the separator. However, once steady state equilibrium is established in the near wellbore region then the producing GOR will usually stabilize and the surface separator should yield fluids suitable for recombination.

On the other hand, subsurface samples provide the best

opportunity of achieving a representative reservoir fluid. The subsurface samples are collected by lowering a special sampling tool through the wellhead into the bottom of the well near the perforations where live reservoir fluid can be captured and brought back to the surface. Prior to collecting subsurface samples the well is typically conditioned by restricting the flow rate in order to level out pressure imbalances in the near wellbore region and then shut- in the well for a period of time to allow fluids to collect and equilibrate in the well bore.

3. Sampling of Gas Condensate Reservoirs

In the case of subsurface samples of a gas condensate reservoir, Jeff et al stated that fluid are sometimes subjected to temperature and pressure sensitivities and their results need to be quantified and scrutinized closely. Consequently, for gas condensate systems there is no guarantee that a bottom hole sample will be superior to surface samples and therefore all results need to be closely examined. Subsurface sampling is not recommended for gas condensate or wet gas

because the volume of fluid sampled gives low liquid recovery and unrepresentative heavy components analysis, possible segregation of the liquid at the well bottom Bottom hole sampling and liquid not totally recovered during transfer of bottom hole sample. Furthermore, for surface sampling the well should be sampled initially, produce the well with small drawdown to minimize formation of a condensate ring near the well bore and finally stabilize the well rate above minimum gas velocity but there are difficulties encountered during surface sampling of gas condensate such as possible liquid carryover at the separator and two different GOR can give the same dew point.

4. PVT Experiments

The following are the major black oil and gas condensate PVT experiments

- Constant Composition Expansion (Oil)
- Differential Vaporization (Oil)
- Separator test/Flash Liberation (Oil)
- Constant Composition Expansion (Condensate Gas)
- Constant Volume Depletion (Condensate Gas)
- Viscosity Measurement
- Compositional Analysis

5. Sample Quality Check

The samples for Akpet GT9 and GT12 reservoirs were validated through their opening pressures and saturation pressure for quality control of samples, check for separator liquid and air contamination for separator gas. Also, composition analysis for the reservoir fluids composition up to C11+ or C20+ and physical recombination for field gas-oil ratio (GOR) correction to ensure that the fluid sample used in the PVT analyses is representative. Sometimes the measured value can be incorrect but a consistency check was performed before starting the tuning process which is almost impossible to match everything perfectly. It is worthy to not that when performing the PVT analysis, one of the experiments may worsen the others. Therefore, the validity of the recombination is:

- constant composition expansion: saturation pressure
- most often, gas condensates are saturated, in equilibrium with an oil ring in the reservoir
- $P_{sat} = P_{res}$: gas condensate saturated; production testing and recombination are correct
- $P_{sat} > P_{res}$: impossible; example: commingle production from two zones, one of each being oil
- $P_{sat} < P_{res}$: undersaturated gas condensate, influence of the GOR, liquid deposit in the wellbore

Validity of PVT samples can also be confirmed by generating Buckley and Mass Balance plots and a significant deviation from linearity imply physical errors in sampling and sample recombination.

Buckley Plot (or Campell Diagram)

For HC gas and liquid phase in equilibrium there is a linear relationship between the log of the individual

component k values & their respective critical temperatures squared. Figure 2 present Akpet GT9 Buckley plot. It should be noted that as components become less paraffinic in nature their deviation from linearity increases.

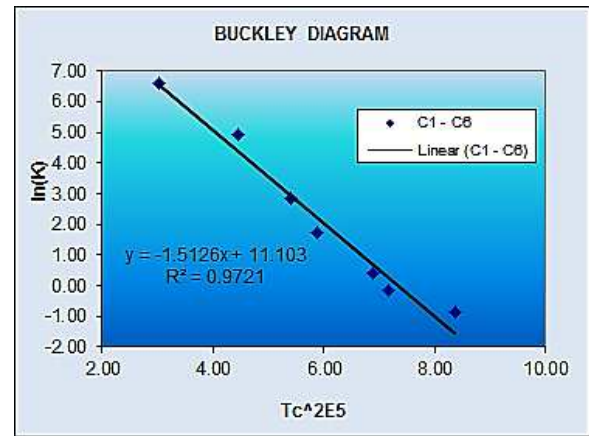


Figure 2. Akpet GT9 Buckley plot.

The deviation (Figure 2) from linearity implies non-equilibrium separation, thus indicating error in analysis or numerical data reporting.

Mass Balance Diagram

This is based on the following general flash equation:

$$Fz_i = Lx_i + Vy_i \quad (1)$$

Where F, L & V are the molar flow rates of feed, flashed liquid and flashed vapour respectively.

z_i , x_i & y are the compositions of feed, flashed liquid and flashed vapour respectively

Equation 1 can be re-arranged as:

$$\frac{y_i}{z_i} = \frac{Lx_i}{Vz_i} + \frac{1}{V} \quad (2)$$

This is a linear equation and a plot of $\frac{y_i}{z_i}$ vs $\frac{x_i}{z_i}$ is a straight line with gradient $-1/V$ as shown in Figure 3.

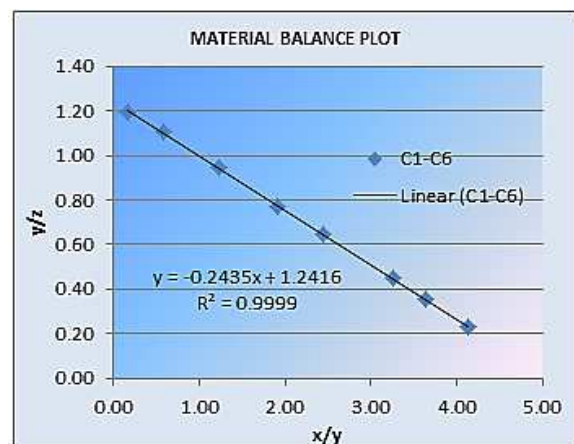


Figure 3. Akpet GT9 material balance plot.

No deviation in the material balance diagram (Figure 3); it indicates no arithmetic errors in the mathematical data

recombination.

6. Deductions from the PVT Study

- (a) Parameters for oil in place evaluation
- (b) Fluid composition analysis
- (c) Understand fluids behaviour during production
- (d) Numerical simulations at the field scale.

7. Methodology

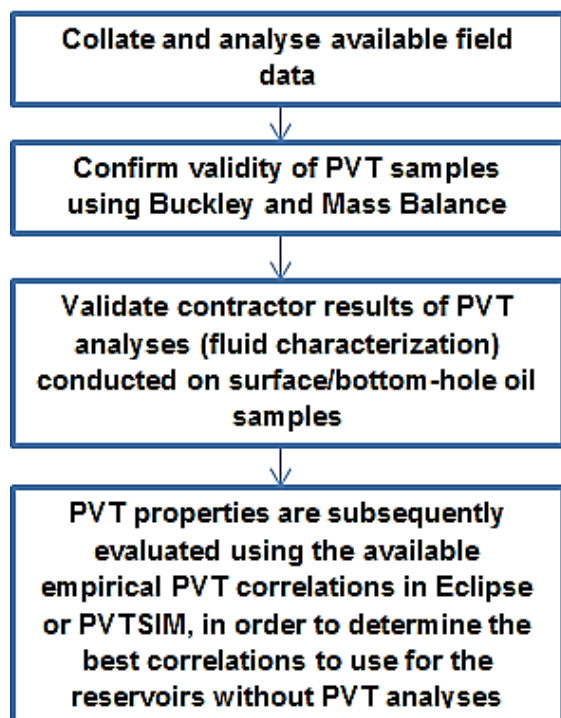


Figure 4. Study methodology.

8. GT9 and GT12 PVT Data Availability

The PVT analysis for Akpet GT9 and GT12 reservoir has been carried out. This is in line with fitting an Equation of State (EOS) to the laboratory PVT experimental data and then using the EOS to produce ECLIPSE black oil PVT tables and EOS model for use in dynamic modeling of the Akpet reservoir dynamic simulation. Laboratory PVT Data reports were made available for the analysis. The reservoir fluid types and sampling points are depicted in the Table 1.

Table 1. GT9 and GT12 sampling date and point.

Reservoir Level	Fluid Type	Sampling Date	Sampling Point
GT9	Gas Condensate	June 17, 1991	Surface recombined
GT12	Black Oil	February 06, 1984	Bottom Hole

The experimental observations used in the analysis are:

1. Saturation pressure (Dew point) at reservoir temperature (black oil and compositional)

2. Constant composition expansion (black oil and compositional)
 - (a) Relative volume
 - (b) Vapor Z factor
 - (c) Liquid Drop Out
3. Differential Liberation/Vaporization (black oil only)
 - (a) Vapour Z factor
 - (b) Liquid density
 - (c) Gas-Oil ratio
 - (d) Relative volume (Formation volume factor)
 - (e) Gas gravity
 - (f) Liquid viscosity
 - (g) Vapor viscosity
4. Constant Volume Depletion (compositional only)
 - (a) Retrograde liquid drop out
 - (b) Cumulative fluid produced
 - (c) Vapor Z factor
 - (d) Specific gravity of produced fluid plus
 - (e) Mole weight of produced fluid plus
 - (f) Final weight of produced fluid plus
 - (g) Produced vapor composition
5. Separator test (black oil and compositional)
 - (a) Gas-Oil ratio
 - (b) Stock tank formation volume factor

9. Data Analysis

The laboratory PVT data analysis for the Akpet GT9 indicates the fluid type to be a gas condensate system while GT12 to be black oil.

Fluid Definition

In GT9 and GT12 reservoirs, a total of twelve (12) components were defined in the characterization; eight (8) pure light hydrocarbons (from C1 to C6), two non-hydrocarbons (N2 and CO2) and heavy components lumped as C7+ fraction. The C7+ of GT9 is characterized with a mole weight of 130.5 and specific gravity of 0.77423 respectively and the sample gave an experimentally derived dew point of 4633 psia. While GT12 is characterized with a mole weight of 205.74 and specific gravity of 0.83184 respectively. Table 2 shows the fluid composition of the surface recombined fluid sample.

Table 2. GT9 and GT12 fluids compositions.

Component	GT9	GT12	Wt. Fraction%
	Mole%	Mole%	
N ₂	0.06	1.02	0.42973
CO ₂	3.72	1.84	1.1397
H ₂ S	0	0	0
C1	78.89	53.46	12.07
C2	5.93	5.86	2.4799
C3	3.61	4.81	2.9851
iC4	0.83	1.27	1.0389
nC4	1.29	2.52	2.0614
iC5	0.57	1.23	1.249
nC5	0.49	1.52	0.91388
C6	0.67	0.9	1.1397
C7+	3.94	25.5	73.835

10. Results

The PVT analysis for Akpet GT9 and GT12 reservoirs was carried out. This is in line with fitting an EOS to the laboratory PVT experimental data and then using the Equation of State to produce ECLIPSE black oil PVT tables and EOS model for use in dynamic modeling of the Akpet reservoir dynamic simulation.

Analysis of GT9 Results

Gas condensate systems are known to exhibit mass transfer and compositional changes on pressure depletion. Hence, the mathematical formulation of a Compositional Simulator is such that for each time –step, the system composition is determined for each grid block. It is therefore necessary to further reduce the 12 components to an acceptable minimum to gain computing time. The 12 components was lumped into four (4) and subsequent split of the C6C7 heavy component into 3 pseudo components to give a final six (6) grouped components as shown in Tables 3 & 4.

Table 3. Grouped fluid composition.

Components	Mol%	Mol Wt	Specific Gravity
C1	78.89		
C2NC	9.71	35.398	0.63731
C3C5	6.97	52.856	0.58474
C6C7	4.61	123.74	0.76126

Table 4. Final Grouped Composition.

Components	Mole Fraction%	Weight Fraction%	Mol Weight	Specific Gravity
C1	78.89	49.854		
C2NC	9.71	13.539	35.98	0.63731

Components	Mole Fraction%	Weight Fraction%	Mol Weight	Specific Gravity
C3C5	6.79	14.137	52.856	0.58474
FRC1	1.909	5.6442	75.06	0.70387
FRC2	2.0574	10.551	130.2	0.75838
FRC3	0.6435	6.2746	247.48	0.82729

A material balance check was carried out on the CVD experiment using the vapour composition, equilibration ratio - Log (Ki) and the Hoffman – Crump- Hocott plots. This is necessary in order to identify and correct measurement errors and data inconsistencies which manifest as negative liquid moles at some pressure depletion stages of the CVD experiment. An adjustment of the reported moles recovered was made to correct these errors before grouping, splitting and subsequent regression.

EoS Modeling

The final 6 grouped component is used in modeling fluid sample. The fluid model was defined with the 3-Parameter Peng-Robinson (PR3). This 3-Parameter Peng Robinson (EOS) and Lohrenz-Bray-Clark (LBC) viscosity correlation were used to fit the simulated results to the experimental data. The parameters tuned for the various fluid properties to obtain a match are as follows:

- Saturation pressure – Omega A
- Vapour Z factor – Volume Shift
- Liquid dropout – Pcirt and Tcrit
- Viscosity – Critical Volume

A calculated dew point pressure of 4630.113psia (Lab experimentally determined = 4633 psia) is obtained at the end of tuning. The results and plots from the PVT analysis on the Akpet GT9 reservoir are depicted in Figure 6 to 14.

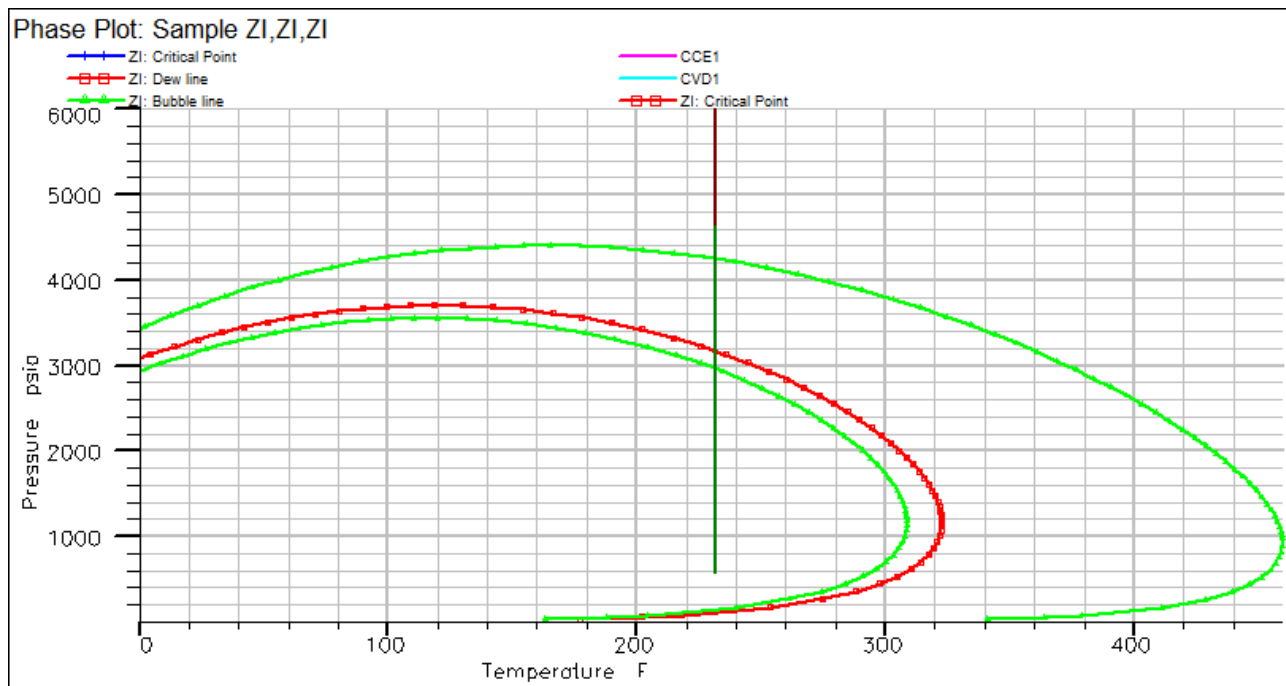


Figure 5. Phase Plot prior and after splitting of the plus fraction.

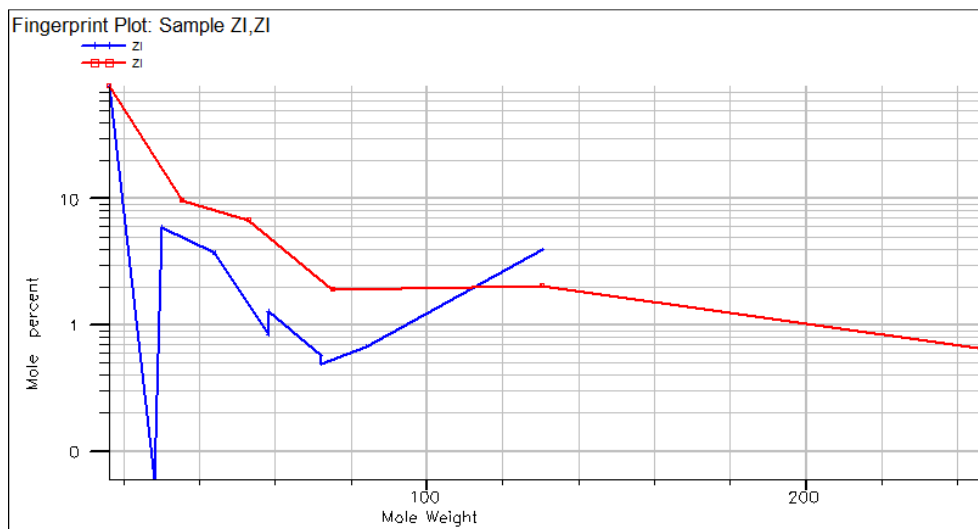


Figure 6. Fingerprint plot, prior and after split of the plus fraction.

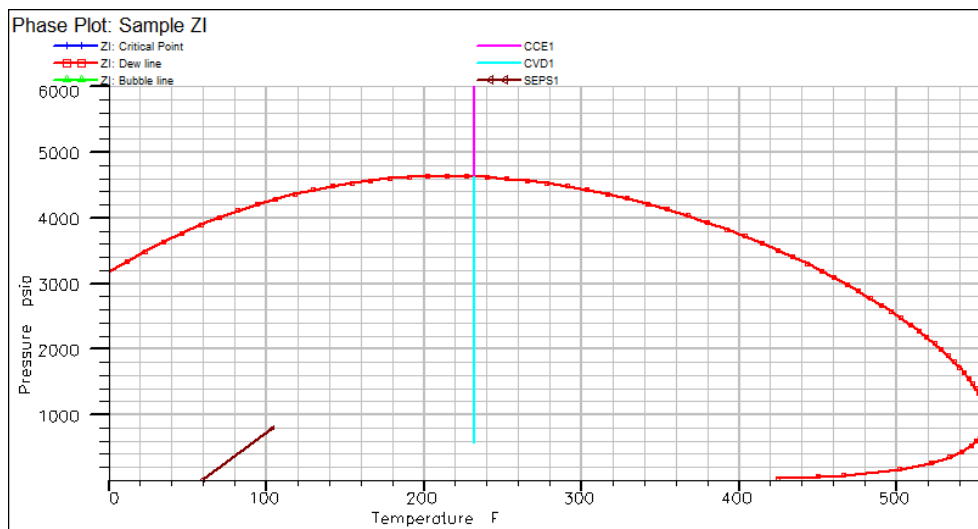


Figure 7. GT9 Final Phase plot.

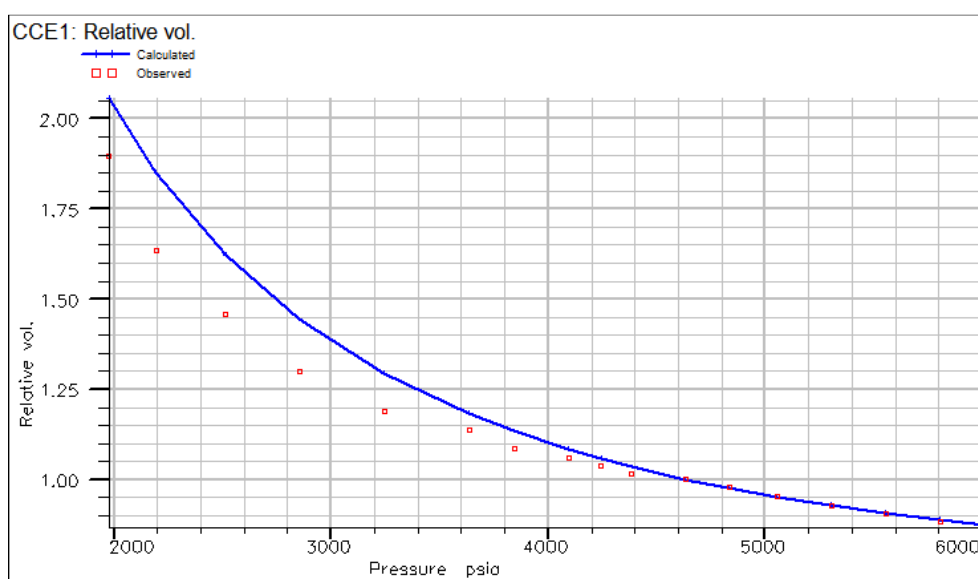
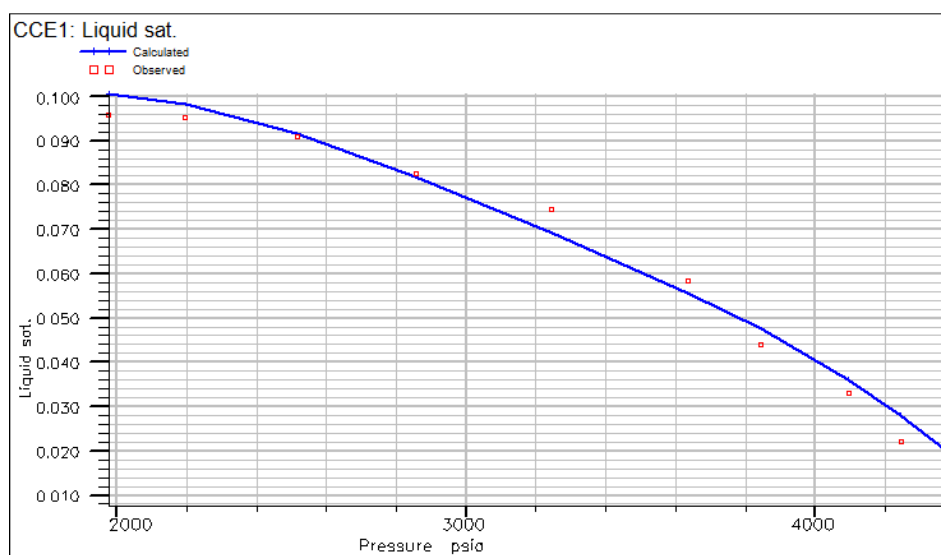
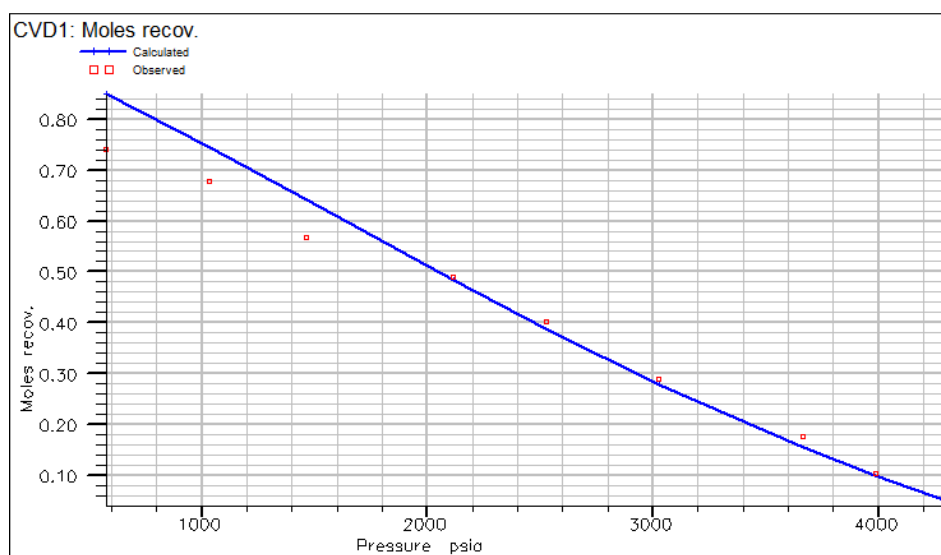
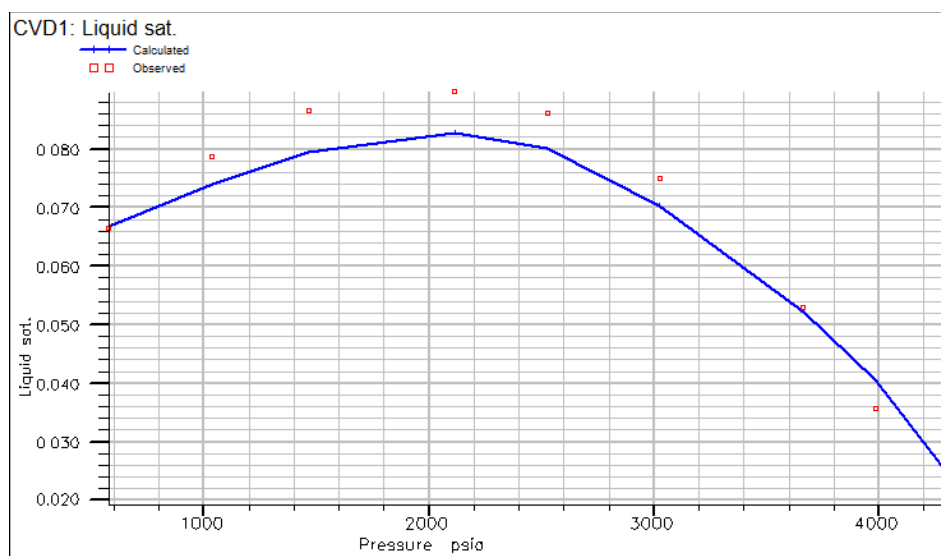


Figure 8. CCE Relative Volume.

*Figure 9. Liquid drop out.**Figure 10. Moles recovered.**Figure 11. CVD Liquid drop out.*

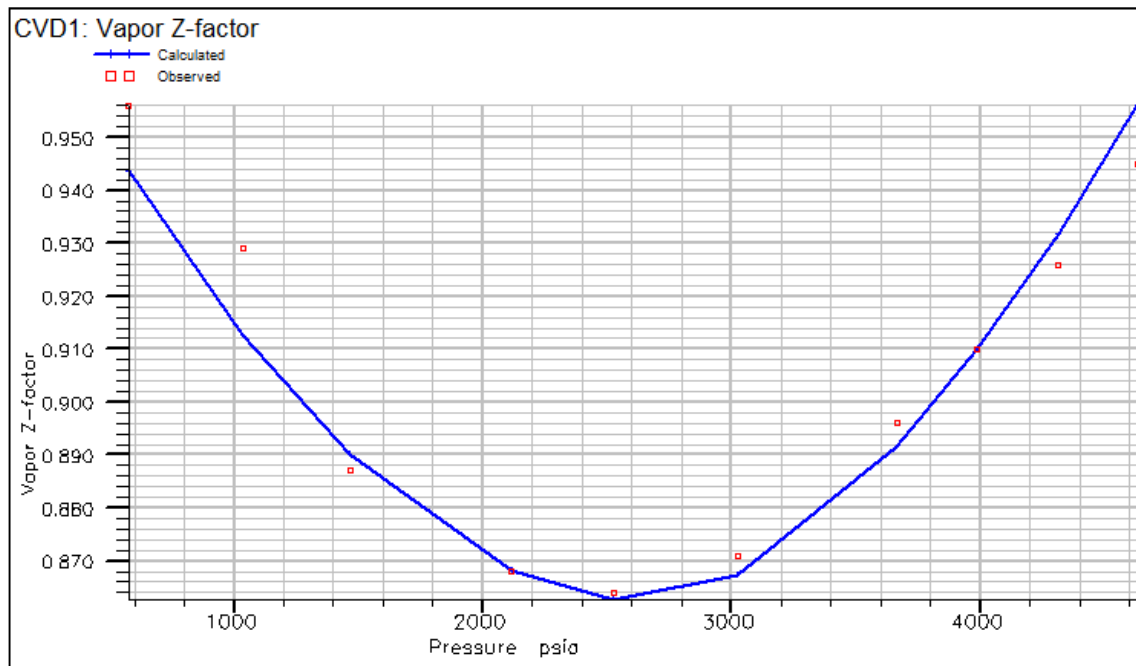


Figure 12. CVD Vapour Z factor.

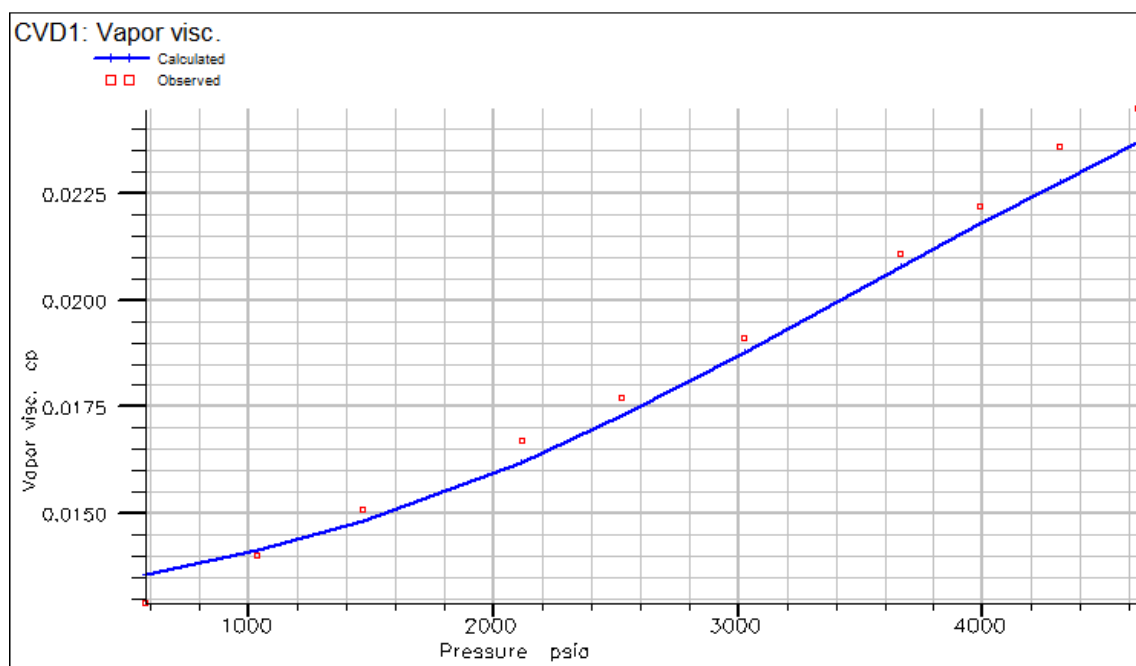


Figure 13. CVD Vapour Viscosity.

Composition gradient analysis

At the attainment of the matched EOS model, a composition versus depth experiment (COMPG) was performed and a plot generated as shown in Figure 14.

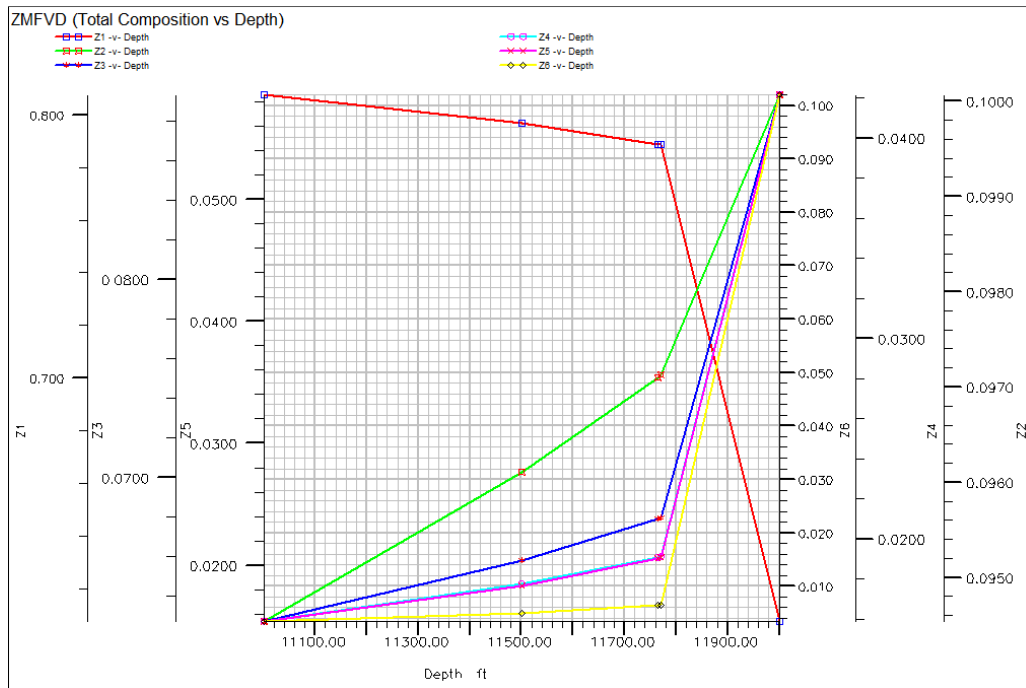


Figure 14. GT9 fluid composition with depth.

Analysis of GT14 Results

Adjustment of Differential Liberation Data to Separator conditions

Prior to fitting an Equation of State (EOS) model to the laboratory data, adjustments were made to the Differential Liberation formation volume factor and solution Gas oil ratio data to the reported separator conditions. Table 5 depicts the reported formation volume factor, solution gas oil ratio and the corresponding adjusted values (procedure for adjustment is given in appendix 1).

Table 5. Formation volume factor and Solution gas oil ratio data.

Pressure (psia)	GOR (Mscf/stb)	Bo (b/stb)	Adjusted GOR (Mscf/stb)	Adjusted Bo (b/stb)
6414.7	1.924	0	1.703	
6059.7	1.936	0	1.7132	
5708.7	1.948	0	1.7235	
5348.7	1.96	0	1.735	
4992.7	1.975	0	1.7475	

Pressure (psia)	GOR (Mscf/stb)	Bo (b/stb)	Adjusted GOR (Mscf/stb)	Adjusted Bo (b/stb)
4732.7	1.989	1736	1.368	1.758
4299.7	1.833	1446	1.1395	1.6429
3585.7	1.666	1119	0.8818	1.5181
2868.7	1.546	864	0.6808	1.4285
2158.7	1.442	655	0.516	1.3508
1458.7	1.351	467	0.368	1.2828
742.7	1.263	287	0.226	1.217
14.7	1.081	-	0	1.081

3-parameter Peng Robinson Equation of State (EOS) and Pedersen viscosity correlation was applied to the fluid model. The ternary and phase envelope plot of the fluid system is shown in Figure 15 and 16. At a reservoir temperature of 229°F, the system is far removed from the critical point and is considered black oil with a bubble-point pressure of 4732.7 psia as recorded from the laboratory experiment. The bubble-point pressure was match at 4732.65 psia.

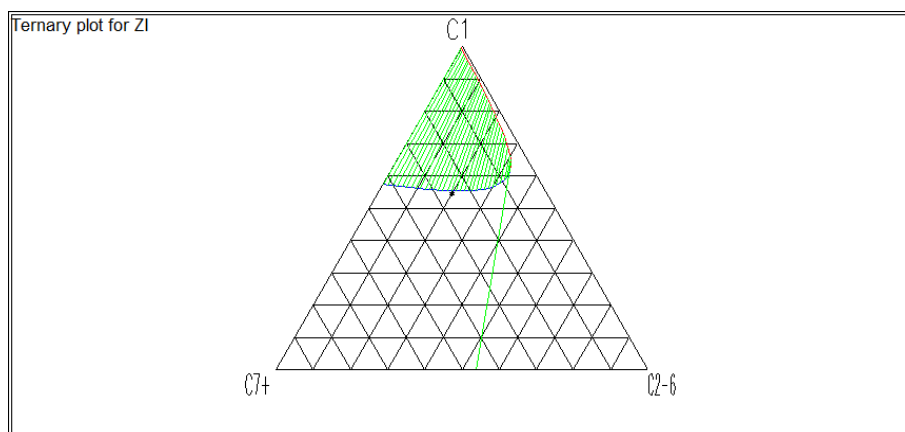


Figure 15. Ternary plot for GT12 reservoir fluid.

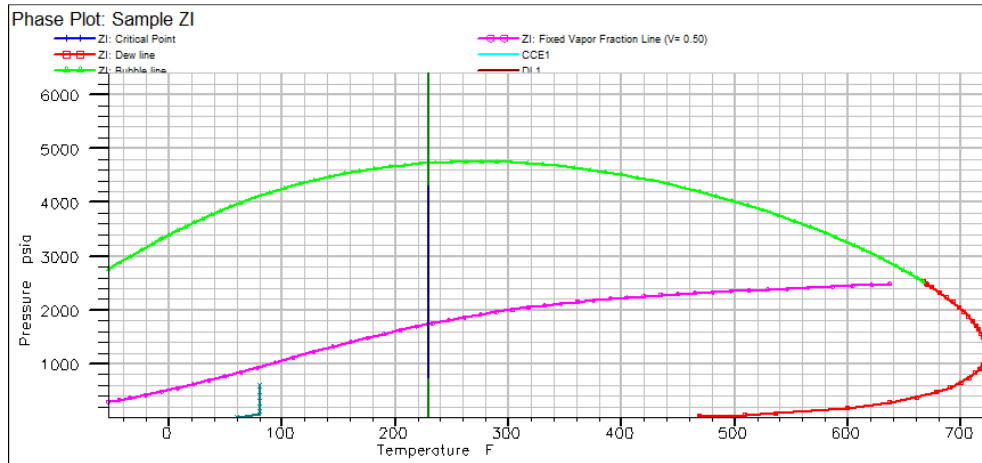


Figure 16. Phase Envelope Plot.

Equation of State (EoS) Modeling

The fluid twelve (12) components defined in the characterization phase have been used in the EOS modeling. The variables tuned during regression include;

- (a) Saturation Pressure: Critical Pressure and weighting
- (b) Vapour Z factor, Liquid Density, GOR and Bo:

Volume shift

- (c) Vapour and Liquid Viscosity: Zcrit and the Lorenz Bray Clark viscosity correlation coefficients are allowed to change when regressing.

The results and plots from the PVT analysis on the Akpet GT12 reservoir are depicted in Figures 17 – 21.

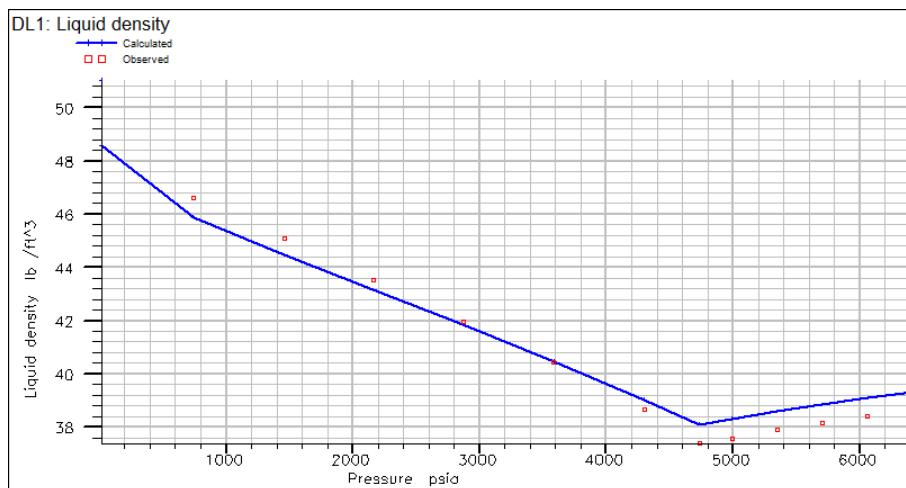


Figure 17. DL Liquid density plot.

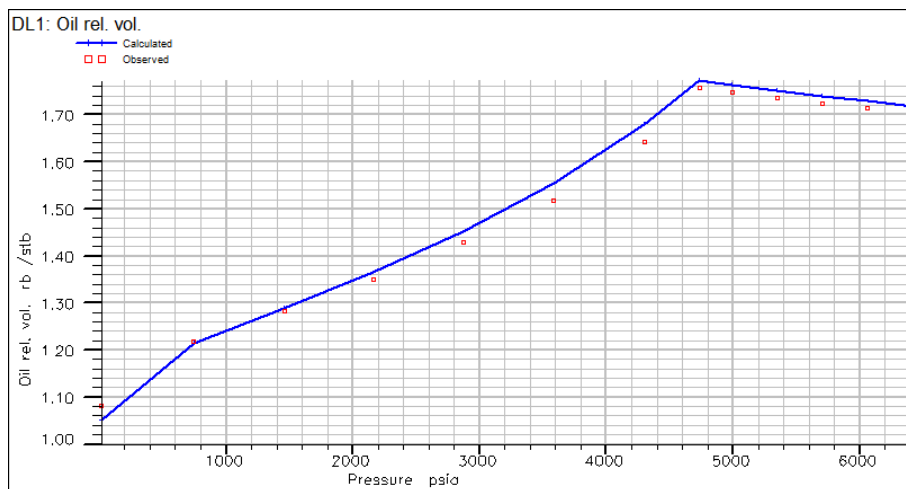


Figure 18. Formation volume factor plot.

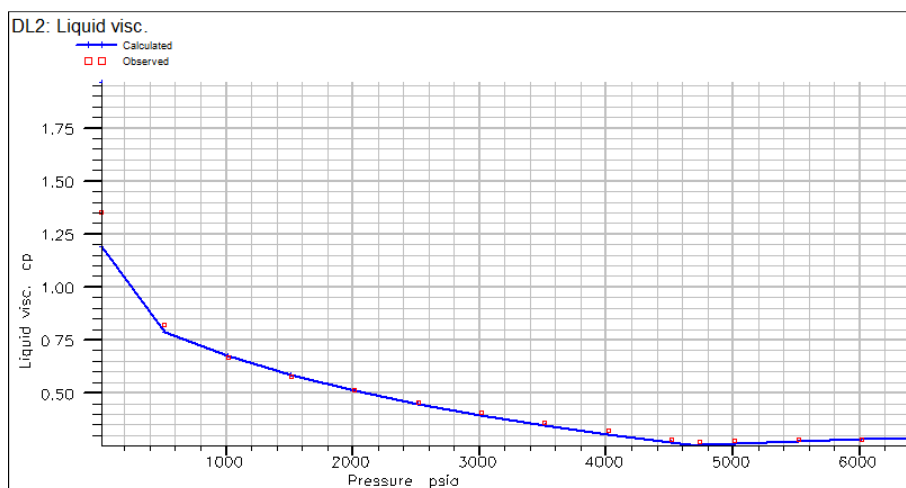


Figure 19. Liquid viscosity plot.

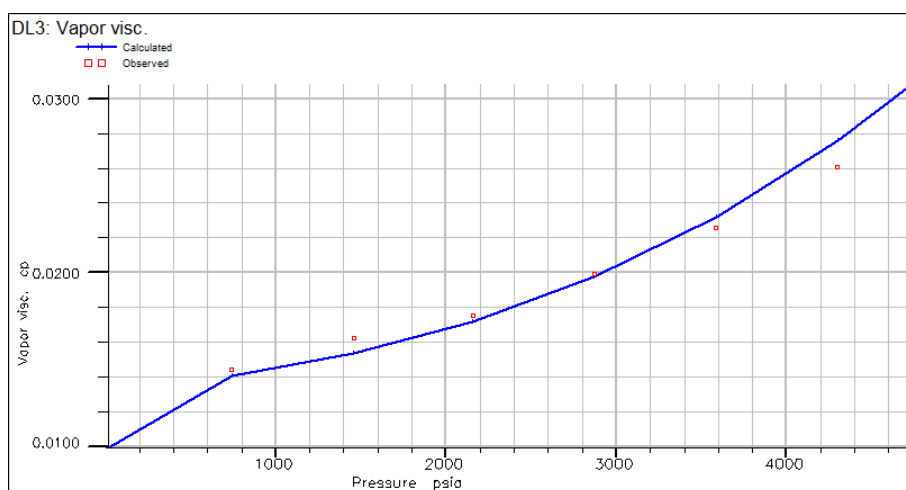


Figure 20. Vapour Viscosity.

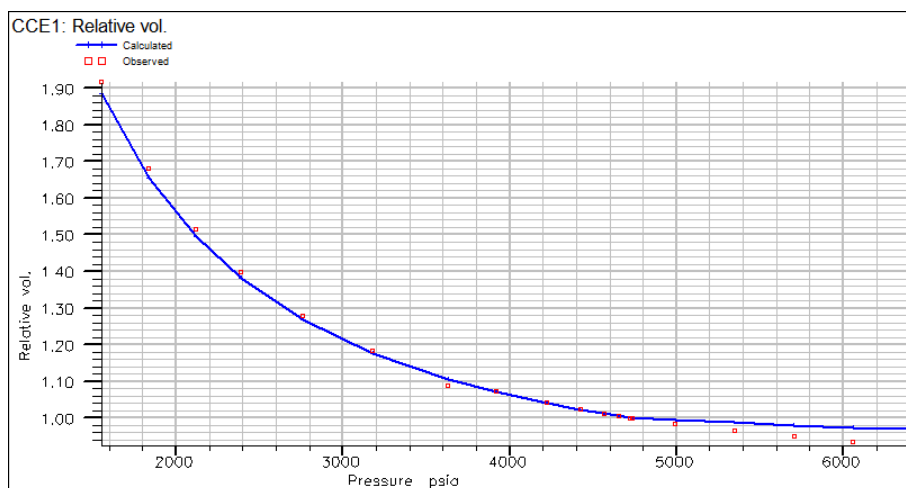


Figure 21. Relative volume from Constant Composition Expansion.

Live oil and Dry gas tables

At the end of the EOS modeling, eclipse PVT look up tables for live oil and dry gas were generated to serve as input during the dynamic simulation. Figure 22 & 23 depict the oil and gas table plots respectively.

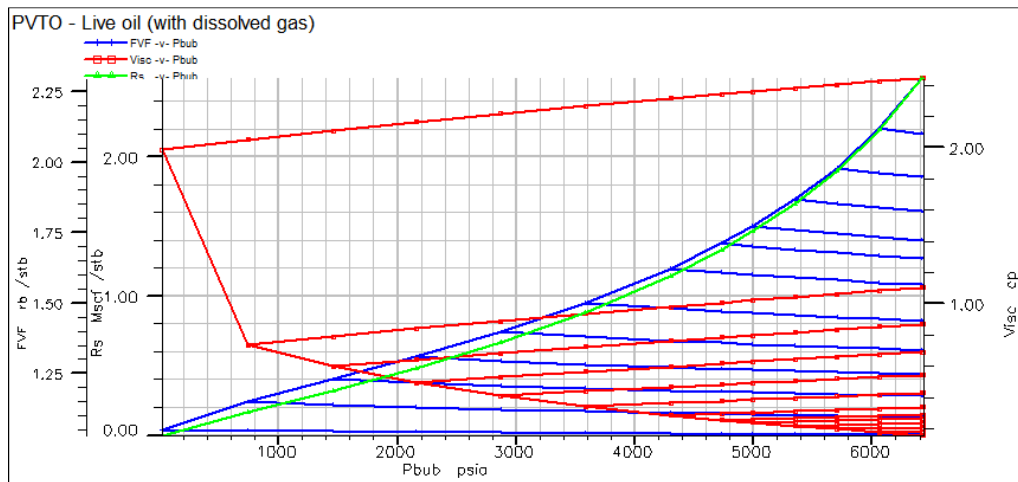


Figure 22. Live oil PVT plot.

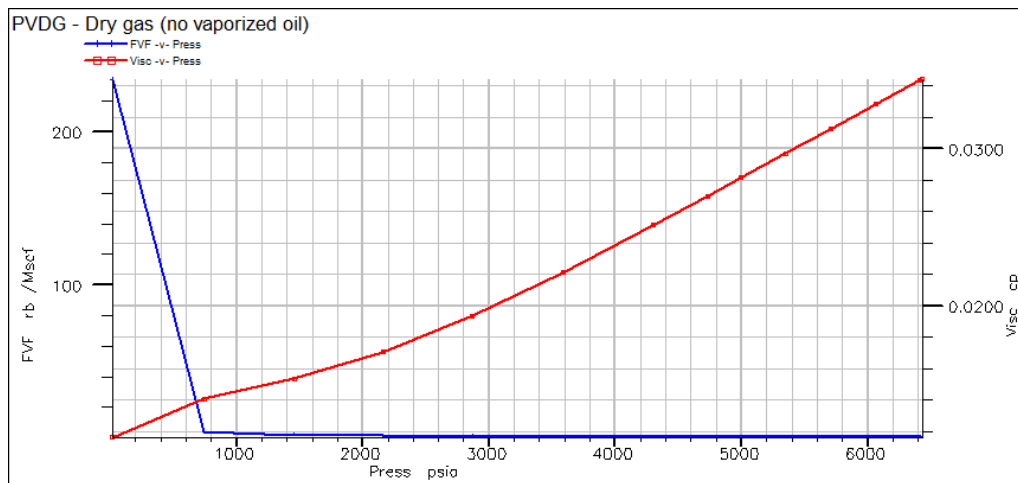


Figure 23. Dry gas PVT Plot.

11. Conclusion

Based on the analysis of Akpet GT9 and GT12 PVT Reports, the following conclusions were drawn.

- The sample would not be a representative of the reservoir fluid if the reservoir pressure is close to the bubble point pressure or low permeability of the reservoir.
- Maximum bottom hole pressure was obtained by reducing the flow rate at the surface and sample as soon as possible during the field life.
- The fluid samples of Akpet GT9 and GT12 were validated with Buckley and material balance plot and the deviation from linearity implies non-equilibrium separation which indicates error in analysis or numerical data reporting. It should be noted that as components become less paraffinic in nature their deviation from linearity increases.
- The fluid composition was reduced from twelve to four groups to minimize the computing time since the mathematical formulation of a compositional simulator is such that for each time-step, the system composition is determined for each grid block.

- The differential vaporisation was able to simulate the initial liquid fraction remaining in the reservoir

Appendix

Procedure for adjusting the oil formation volume factor and solution gas oil ratio of the Differential Liberation experiment

- From the separator (flash) test, obtain the oil formation volume factor and solution gas oil ratio at the optimum separator condition. The optimum separator condition coincides with the reported minimum oil formation volume factor of the flash data
- Recalculate the oil formation volume factor, B_o , below the saturation pressure of the DL experiment using equation 1 in appendix 1
- Recalculate the oil formation volume factor above the saturation pressure by multiply the formation volume factor of the flash data by the relative volume of the Constant Composition Expansion experiment i.e using equation 2
- The adjusted solution gas oil ratio is obtained by applying equation 4.

Adopted procedure for Smoothing the oil relative volume of the Constant Composition Expansion (CCE) test

1. Determine the Y function for all pressures below the saturation pressure using equation 5 in appendix 1
2. Plot the Y function versus pressure on a regular Cartesian scale
3. Determine the intercept (a) and slope (b) of the best fit straight line
4. Recalculate the relative volume at all pressure below the saturation using equation 6

Equations

$$B_{oi} = B_{obf} + \frac{(B_{obd} - B_{obi})}{(B_{odn} - B_{obn})} (B_{odn} - B_{obf}) \quad P \leq P_b \quad (1)$$

$$B_{odi} = V_{rel} * B_{obf} \quad P > P_b \quad (2)$$

$$R_{si} = R_{sdi} \left(\frac{R_{sbf}}{R_{sbd}} \right) \quad P > P_b \quad (3)$$

$$B_{oi} = B_{od} \left(\frac{B_{obf}}{B_{obd}} \right) \quad (4)$$

$$Y = \frac{(P_b - P)}{P(V_{rel} - 1)} \quad (5)$$

$$V_{rel} = 1 + \left[\frac{(P_b - P)}{P(a + bP)} \right] \quad (6)$$

Nomenclature

Bo = oil formation volume factor

Bob = oil formation volume factor at bubble point pressure

Bobd = oil formation volume factor at bubble point pressure from differential liberation experiment

Bobf = Bubble point oil FVF flashed through the separator to stock tank conditions

R_s = Solution GOR, scf/stb

R_{sbd} = Bubble point solution GOR obtained by differential liberation test, scf/stb

R_{sbf} = Bubble point solution GOR obtained from the separator test

R_{sdi} = solution GOR obtained from differential liberation test

P_b = saturation (Bubble point) pressure

P = pressure

V_{rel} = relative volume at pressure p

Subscripts

d = differential liberation test

f = flash liberation (separator) test

i = ith differential stage

n = number of stages in the differential liberation test

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