**Open Journals of Engineering Science (OJES)**
**ISSN: 2734-2115**
**Article Details:**
openjournalsnigeria.org.ng/pub/ojes20200101.pdf
Article Ref. No.: OJES20200101
Volume: 1; Issue: 1, Pages: 1-13 (2020)
Accepted Date: March 05, 2020


CrossMark
click for updates

**Open Journals Nigeria (OJN)**
Open Access | Bi-annual | Peer-reviewed
www.openjournalsnigeria.org.ng
editorial@openjournalsnigeria.org.ng

**RESEARCH ARTICLE** **OJES20200101**

# EVALUATION OF AKPET GT9 GAS CONDENSATE RESERVOIR PERFORMANCE

**[*1]Okotie, S. and [2]Ogbarode, N. O.**

*[*1]Department of Petroleum Engineering, Federal University of Petroleum Resources (FUPRE), Effurun, Delta State, Nigeria.*
***[*]Phone:** +2348032608026 [*]**Email:** okotie.sylvester@gmail.com*
*[2]Department of Petroleum Engineering, Federal University of Petroleum Resources (FUPRE), Effurun, Delta State, Nigeria.*
***Phone:** +234805200023 **Email:** ogbanap@gmail.com*

## ABSTRACT

To effectively evaluate a gas condensate reservoir performance, the reservoir engineer must have a reasonable amount of knowledge about the reservoir to adequately analyze the reservoir performance and predict future production under various modes of operation. Due to the multiphase flow that exists in the reservoir, characterization of gas condensate reservoirs is often a difficult task with the variation of its overall composition in both space and time during production which complicates well deliverability analysis and the sizing of surface facilities. This study is primarily concern with the evaluation of a gas condensate reservoir performance of Akpet GT 9 Reservoir in the Niger Delta region of Nigeria with material balance analysis tool "MBal" without having to run numerical simulations. The result obtained with MBal on the analysis of Akpet GT 9 reservoir gave 23.934 Bscf of gas initially in place which compares favorably with the volume obtained from volumetric techniques. Results also shows that the most likely aquifer model is the Hurst–Van Everdingen - Dake radial aquifer and the reservoir is supported by a combined drive of water influx and fluid expansion.

**Keywords:** *gas condensate performance, MBal, dew point temperature, liquid loading, temperature, pressure.*

## INTRODUCTION

In most parts of the world today, there are many gas condensate reservoirs and each with a unique composition. This implies that the ability of a Reservoir Engineer to predict the behavior of gas condensate reservoirs depends solely on his/her ability to predict the flow characteristics of the fluids in the reservoir. Thus, the main concern of the engineer in carrying out study on the reservoir is to adequately simulate the reservoir with the minimum effort. Gas condensate reservoir can be defined as a low-density mixture of hydrocarbon liquids that are present as gaseous components in the raw natural gas produced from many natural gas fields. It condenses out of the raw gas if the temperature is reduced to below the hydrocarbon dew point temperature of the raw gas. However, gas condensate generally has a specific gravity ranging from 0.5 to 0.8, and is composed of hydrocarbons such as propane, butane, pentane, hexane and other hydrocarbons which exist as liquids at ambient temperatures and may contain impurities such as Hydrogen sulfide ($H_2S$), Mercaptans, Carbon dioxide ($CO_2$) etc.

In the production of a gas condensate field, gas is mostly produced with some liquid dropout as the pressure drops below dew point pressure; occurring mostly in the separator and can still be produced in the wellbore which ultimately leads to a restriction in the flow of gas. The temperature and pressure may change once the reservoir fluids enter into the wellbore which causes liquid to drop out within the wellbore and if the gas having the larger fraction does not have enough energy to lift the drop out liquid to the surface, a fallback in the wellbore occurs or liquid loading. If this continuous, the percentage of the liquid will increase and may eventually restrict the gas production. This challenge can be adequately handled with artificial lift technologies such as gas lift, but this will not be considered in this paper.

Figure 1, presents a retrograde gas field whose temperature is greater than the critical point temperature. The curve lines indicate the phase changes as the fluid flows from the reservoir (green vertical line), cools as it goes up through the wellbore and then into the separator. Point A in Figure 1 represents percent increase in liquid with the retrograde condensate field and then decreases with further pressure declines. Thus, condensation and then vaporization occurs which help in the further recovery of liquids.

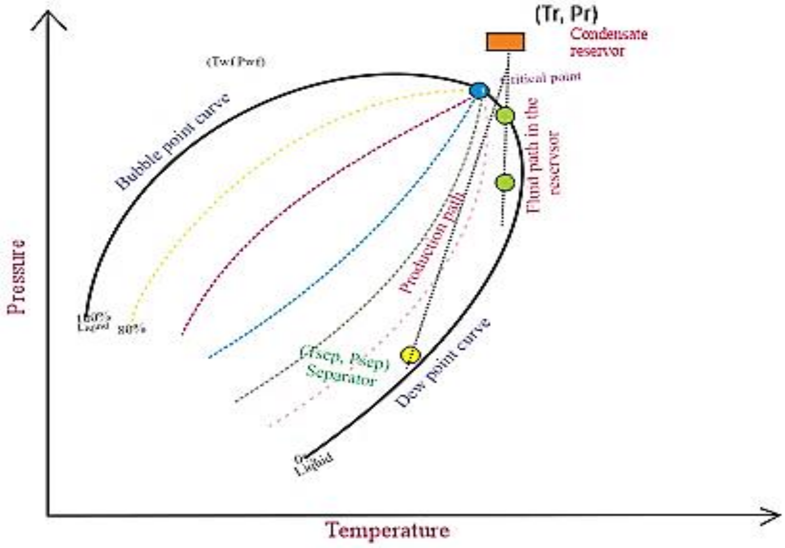


**Figure 1:** Phase envelop of a retrograde gas field

## PREVIOUS WORKS ON GAS CONDENSATE WELL

Thomas *et al.* (2009) stated that to get an insight into gas condensate reservoir, appropriate in situ fluid characterization and performing relevant flow test is key to the success of its performance prediction. They quantified the differences caused by compositional path in API gravity of liquids in solution to be as much as 10 degrees and 110 Daltons differences in molecular weight. It was also observed that the critical condensate saturation was less sensitive to interfacial tension but the end-point saturations are sensitive to interfacial tension.

Babalola *et al.* (2009a) stated that original and best modified black oil models are limited and thus, not adequate for modelling gas condensate reservoirs as a result of the deterministic nature of evaluation. A stochastic gas condensate model is required to match the adequacy and serve optimal recovery techniques. Babalola *et al.* (2009b) transformed the partial differential equation of deterministic method of mass balance into a stochastic technique of Feynman-Kac differential equation by employing some simple and safe assumptions. The stochastic parameter k was determined and found to be zero.

Ahmadi *et al.* (2014) posits that there is a significant decrease in the well productivity as a result of a sharp drop in the effective gas permeability when there is a decrease in the bottom-hole pressure below its dew point due to condensate bank around the gas condensate well. Hence, to adequately predict the performance of the reservoir, an engineer requires a thorough understanding of the fluid behavior. The aim of the work was to compare the various simulation techniques of gas condensate reservoir, to determine the most accurate with cases below and above the gas condensate dew-point.

Olaberinjo and Omole (2004) presented a systematic and inexpensive compositional approach that is based on Cho *et al.* (1985) correlation for calculating gas condensate reservoirs pressure depletion performance with consideration to the properties of liquid and vapor phase with possible presence of impurities such as $CO_2$, $H_2S$ and S.

Gringarten and Al-Lamki (2000) showed that three regions are created with different liquid saturations when the pressure of the reservoir in the vicinity of a well drop, a retrograde condensation occurs below the dew point pressure. Considering the point closer to the well where the liquid saturation reaches a critical value, an inner region forms and the effluent travels as two-phase flow with constant composition. There is an immobile intermediate region where the liquid is less than the critical condensate saturation. This region is characterized by a rapid increase in liquid saturation and a corresponding decrease in gas relative permeability. Away from the well, an outer region has the initial liquid saturation next to the intermediate region.

## STATEMENT OF PROBLEM

The accurate determination of oil and gas initially in place and prediction of the future reservoir performance from any of the reserve estimation methods are of vital importance to the oil and gas industry, also an accurate and reliable production data directly impacts the accuracy of the in-place volume estimate and future performance. Thus, there is a challenge faced in gas condensate fields and how a company should optimize the development of a gas-condensate field, when depletion leaves valuable condensate fluids in a reservoir which builds up near a well because of the drawdown below the dew point pressure, ultimately restricting the flow of gas. The problem of liquid loading can be effectively handled by installing a gas lift or pumping technologies but this is beyond the scope of this study.

## STUDY OBJECTIVES

This study is primarily aimed at the evaluation of a gas condensate reservoir performance of Akpet Reservoir in the Niger Delta region with material balance tool (MBal) without having to run dynamic/numerical simulations. This is important for the optimization of the production strategy of gas-condensate reservoirs, reducing the impact of condensate banking, and improving the ultimate gas and condensate recovery. The objectives were to:

- estimate the Hydrocarbon-in-Place
- evaluate the available drive mechanisms and the strength of the aquifer
- determine the most likely aquifer model and properties
- determine the probable limits of the reservoir

The in-place volumes acquired from the study are subject to validation by static and dynamic simulation.

## MATHEMATICAL MODEL

The calculation of the original oil and gas in place are given in equations 1 – 7:

$$GIP = \frac{43560Ah\emptyset(1 - S_{wc})\,{}^{N}/_{G}}{B_g} \tag{1}$$

$$\gamma_o = \frac{M_o}{API + 131.5} \tag{2}$$

$$M_o = \frac{6084}{API - 5.9} \tag{3}$$

$$\gamma_{well} = \frac{GLR(y_i M_i) + 4585\gamma_o}{M_{air}\left[GLR + 132800\left(\frac{\gamma_o}{M_o}\right)\right]} \tag{4}$$

$$f_g = \frac{{}^{GLR}/_{379.4}}{{}^{GLR}/_{379.4} + 350\left({}^{\gamma_o}/_{M_o}\right)} \tag{5}$$

$$OGIP = GIP.\,f_g \tag{6}$$

$$OIP = \frac{OGIP}{GLR} \tag{7}$$

The derivation of the general material balance equation for a wet gas reservoir is given by equations 10 - 17:

GIP = gas in place, A= area, h= thickness, N/G=net-to-gross ratio, Swc=connate water saturation, $\gamma_o$ *and* $\gamma_{well}$ = specific gravity of well, Bg = gas formation volume factor, yi and Mi=mole composition and molar mass of $i^{th}$ component, $M_{air}$=molar of air, GLR= gas liquid ration, $f_g$= gas fraction at surface, OGIP and OIP = original gas and oil in place.

The derivation of the general material balance equation for a wet gas reservoir is given by equations 10 - 17:

$$n_h = n_{hi} - n_{np} \tag{8}$$

$$n_h = n_{hi}\left(1 - \frac{n_{hp}}{n_{hi}}\right) \tag{9}$$

Using the Real Gas Law, we can express $n_{hi}$ in hydrocarbon pore volume and the fraction $\frac{n_{np}}{n_{hi}}$ in the fractional dry gas production

$$n_h = \frac{p}{zRT} V_{hc} \tag{10}$$

Likewise, if follows for

$$n_{hi} = \frac{p_i}{z_i RT} V_{hci} \tag{11}$$

$$n_{np} = n_{Gp} + n_{Lp} = n_{Gp}(1 + R_{MLG}) \tag{12}$$

$$n_{Gp} = \frac{p_{sc}}{RT_{sc}} G_p \tag{13}$$

$$n_{hi} = n_G + n_L = n_{Gp}(1 + R_{MLG}) \tag{14}$$

By virtue of the Real gas law, for the number of moles of dry gas initially-in-place, we have

$$n_G = \frac{p_{sc}}{RT_{sc}} G \quad (15)$$

Combining Equations (12) to (15), for the ratio $\frac{n_{hp}}{n_{hi}}$ we can write

$$\frac{n_{hp}}{n_{hi}} = \frac{n_{Gp}(1 + R_{MLG})}{n_G(1 + R_{MLG})} = \frac{G_p RT_{sc} p_{sc}}{GRT_{sc} p_{sc}} = \frac{G_p}{G} \quad (16)$$

Substituting Equations (10), (11) and (16) into Equation (8), we obtain

$$\frac{p}{z} = \frac{P_i V_{hci}}{z_i V_{hc}}\left[1 - \frac{G_p}{G}\right] \quad (17)$$

Equation (17) is the General Material Balance Equation for wet-gas reservoirs. It relates the reservoir pressure to the cumulative dry-gas production and contains parameters as the z-factor of the reservoir gas, the amount of dry-gas initially-in-place and the hydrocarbon pore volume. Note that condensate production is not explicitly included in the material balance equation of wet gas reservoirs.

Where p = reservoir pressure and $p_i$=initial pressure, $V_{hc}$ = hydrocarbon pore volume and $V_{hc}$ = the initial condition, Z = z-factor of the reservoir gas and $z_i$= initial condition, R = gas constant, T = absolute reservoir temperature, $n_h$ = number of hydrocarbon moles in place, $n_{hi}$ = number of hydrocarbon moles initially- in- place, $n_{np}$ = number of hydrocarbon moles produced, $n_{Gp}$ = number of moles of produced dry gas, $n_{Lp}$ = number of moles of produced liquid condensate, $R_{MLG}$ = molar condensate/gas ratio $\left(\frac{n_{Lp}}{n_{Gp}}\right)$, $p_{sc}$ = standard pressure, $G_p$ = cumulative dry-gas production expressed in standard volume and $T_{sc}$ = standard absolute temperature. Thus, in this relation, we assumed the z-factor at standard conditions to be unity

## METHODOLOGY

The Material Balance Analysis tool, MBAL, of Petroleum Experts Limited was used for the analysis. The program uses a conceptual model of the reservoir to predict the reservoir behavior and reserves based on the effects of fluids production from the reservoir. Detailed PVT models can be constructed for oils (both black oil and compositional), gases and condensates. Furthermore, predictions can be made with or without well models and the use of relative permeability to predict the number of associated phase productions. MBAL can also be tied into GAP for integrated production modeling studies, providing an accurate and fast reservoir model as long as the assumptions of material balance are valid for the real situation to be modeled. The reservoir pressure, PVT and production data, after careful review, served as input data into the MBAL program. Available geological maps and petro-physical data aided the estimation of the aerial extent of the reservoir and the aquifer.

## PROCEDURE

The Havlena-Odeh and the F/Et vs. We/Et straight line plots of the graphical method incorporating various radial aquifer models were used to evaluate the aquifer properties, match the reservoir pressure and determine the gas initially-in-place (GIIP). The accuracy of the results was validated with the history match of the model's pressure and production. The analysis procedure is as follows:

- Pressure and production data is entered on a Tank basis.
- The matching facility in MBAL is used to adjust the empirical fluid property correlations to fit measured PVT laboratory data. Correlations are modified using a non-linear regression technique to best fit the measured data.
- The graphical method plot is used to visually determine the different Reservoir and Aquifer parameters. The Havlena – Odeh and the F/Et vs. We/Et straight-line plots of the graphical method were used to visually observe and determine the appropriate aquifer model and parameters.
- The non-linear regression engine of the analytical method is used in estimating the unknown reservoir and aquifer parameters and to fine-tune the pressure and production match. This is done for various aquifer models and their standard deviations from the actual field data are compared
- The accuracy of the model is validated by history matching the field pressure and production data with the simulation data.

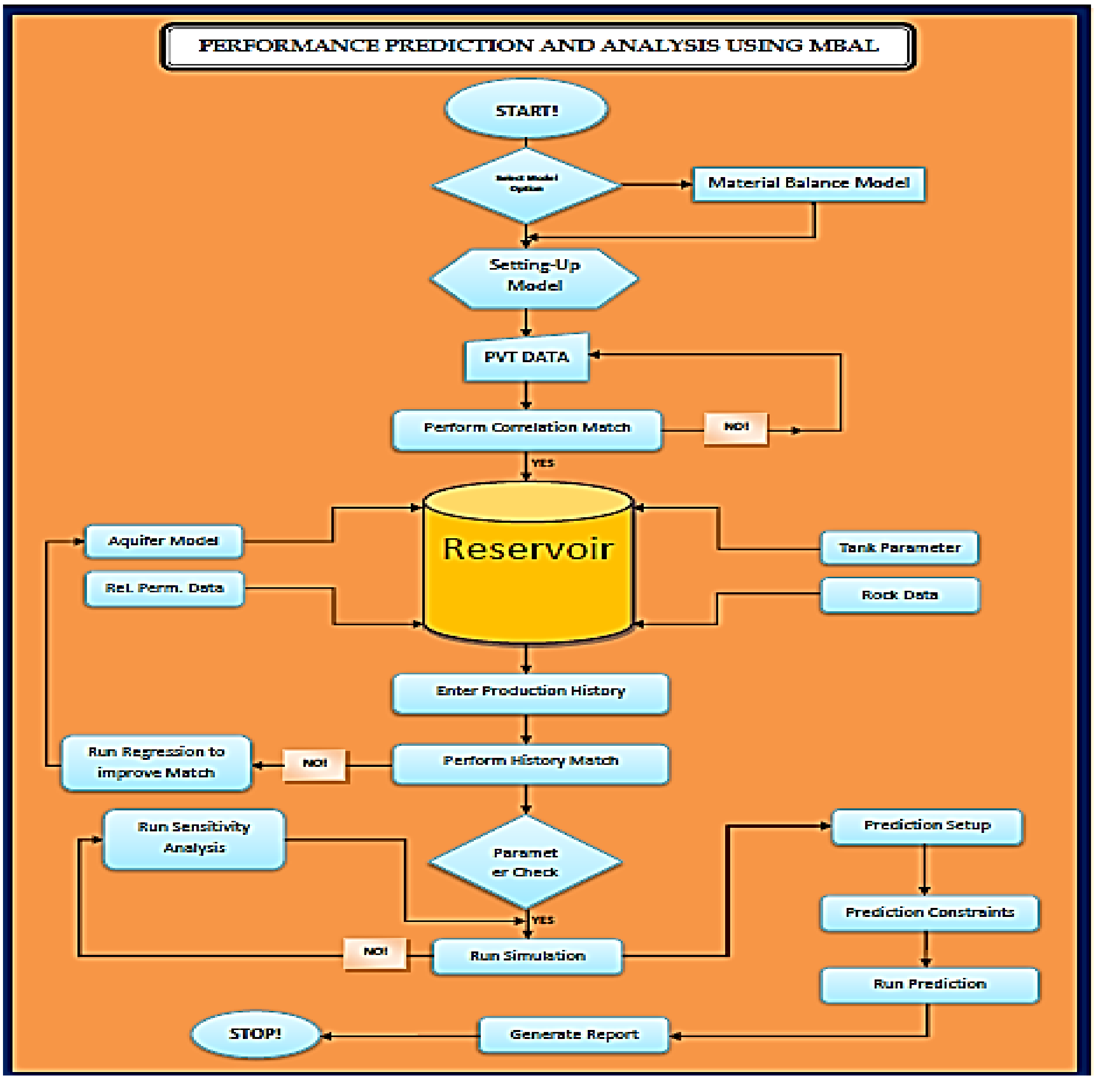


**Figure 2:** Flow chart of workflow in MBal

## DATA

Akpet GT 9 reservoir was analyzed as a gas condensate reservoir. The pressure and production data used in the analysis was provided by an Oil and Gas Company whose identity cannot be revealed due to data integrity issues. The production history spans a period of 23 years (February 1978-December 2001). The PVT, the reservoir (tank) and relative permeability data used in the analysis are shown in Table 1, 2 and 3 respectively.

**Table 1**: Akpet GT 9 Reservoir PVT Properties

| **Parameter** | **Value** | **Parameter** | **Value** |
|---|---|---|---|
| Separator pressure | 800 psia | Water salinity | 120000 ppm |
| Separator temperature | 102 deg F | Dew point at reservoir temp | 4734 psia |
| Separator GOR | 12980 scf/STB | Reservoir temperature | 250 deg F |
| Separator gas gravity | 0.694 sp gravity | Reservoir pressure | 4734 psia |
| Tank GOR | 582 scf/STB | Mole percent H2S | 0.023 |
| Tank gas gravity | 1.283 sp gravity | Mole percent CO2 | 3.82 |
| Condensate gravity | 52.2 API | Mole percent N2 | 0.057 |

**Table 2**: Akpet GT 9 Reservoir (Tank) and aquifer properties

| **Parameter** | **Value** |
|---|---|
| Reservoir thickness | 154 ft |
| Reservoir radius | 6859ft |
| Initial pressure | 4734 psia |
| Outer/inner radius ratio | 13.876 |
| Encroachment angle | 246.23 deg |
| Aquifer permeability | 16.326mD |
| Porosity | 0.18 |
| Connate water saturation | 0.26 |
| Water compressibility | 4.063E-6 1 1/psi |
| Original gas in place | 238.23 Bscf |
| Start of production | 2/28/1978 |

**Table 3**: Akpet GT 9 Relative Permeability data

| **Parameter** | **Residual saturation** | **End point** | **Exponent** |
|---|---|---|---|
| Krw | 0.17 | 0.35 | 3 |
| Kro | 0 | - | 0 |
| Krg | 0.054 | 0.89 | 1.23 |

## RESULT AND DISCUSSION

Constraints

- Unknown aquifer characteristics and properties

Inferences from the Material Balance analysis of the Akpet GT 9 reservoir are as follows:

- The GIIP is 231.934 Bscf..
- The most likely aquifer model is the Hurst–Van Everdingen - Dake radial aquifer.
- The reservoir is supported by a combined drive of water influx and fluid expansion as shown below (Figure 4).

The summary of the aquifer parameters used in the Material Balance calculations and the source of each data are depicted in Table 4.

**Table 4**: Summary of Input Data for the Aquifer model of Akpet GT 9 Reservoir

| **Parameter** | **Value** | **Source** |
|---|---|---|
| Aquifer Permeability (md) | 16.45 | Regression in MBAL |
| Encroachment Angle (deg.) | 241.48 | Fault Polygon |
| Reservoir Radius (m) | 6500 | Estimation from seismic map |
| Outer/Inner radius (Ratio) | 13.56 | Estimation from seismic map |
| Reservoir Thickness | 144 | Logs |

The parameters used to obtain the history match compares favorably with the expected values. The plots generated from the more likely case model are shown in Figures 3, 4, 5 and 6 respectively.

The Gas initially in place (GIIP) for the reservoir was given from volumetric technique as 231.68 Bscf and after the history match performance of the production history (Figure 3); the result from the graphical method using straight line approach incorporated into the Mbal software gave GIIP value of 231.934 Bscf. Thus, since this value agrees with the one calculated with the volumetric method at the initial stage of the reservoir; it can, therefore, be used to predict further the performance of the Akpet GT 9 reservoir to abandonment pressure.

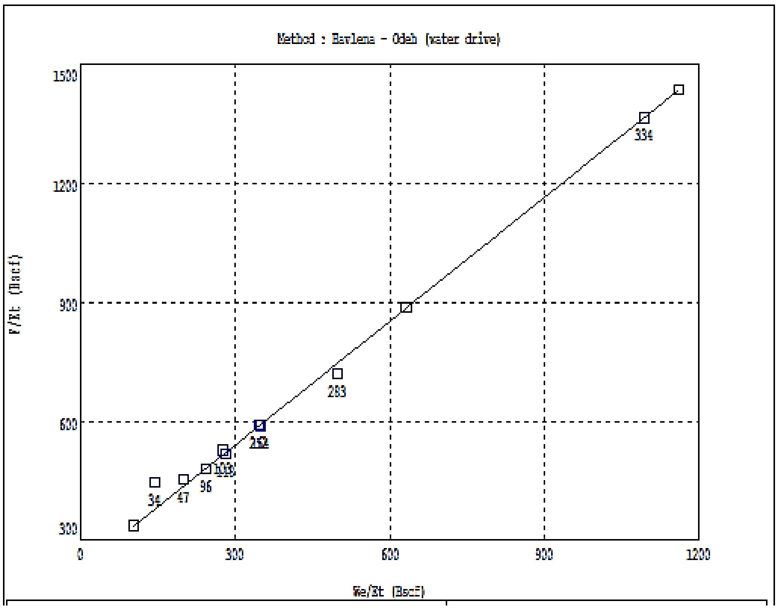


Figure 3: Akpet GT 9 Reservoir Graphical Diagnostic Plot

The Hurst-Van Everdingen-Dake model was selected as the most likely case. The parameters used to obtain the history match (Figure 5) and the OIIP from the model with the Hurst-Van Everdingen–Dake radial aquifer compares favorably with the expected values. This reservoir is supported by a combined drive of water influx and fluid expansion (Figure 4). It indicates that water is the predominant drive mechanism for this reservoir with a reasonable amount for the fluid expansion and a negligible amount for pore volume compressibility

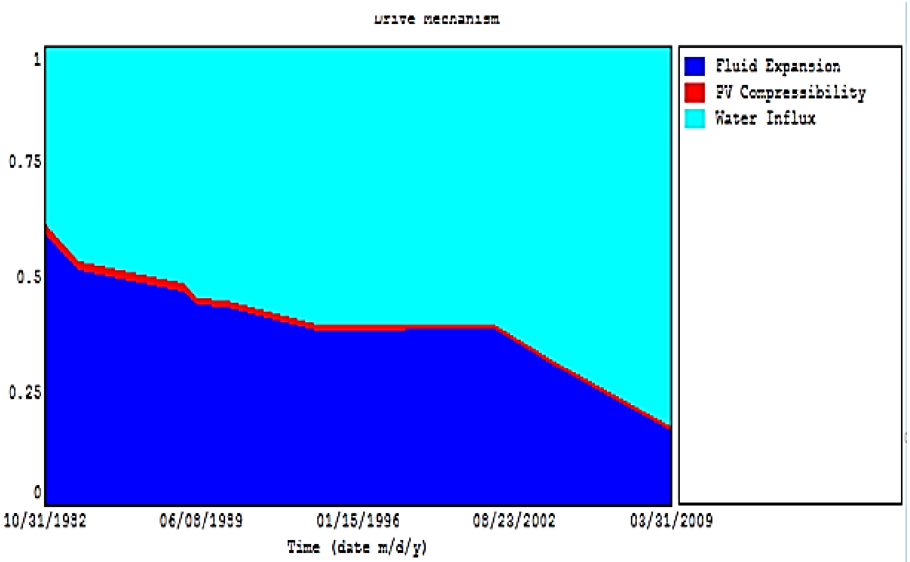


Figure 4: Akpet GT 9 Reservoir Drive Mechanism Plot

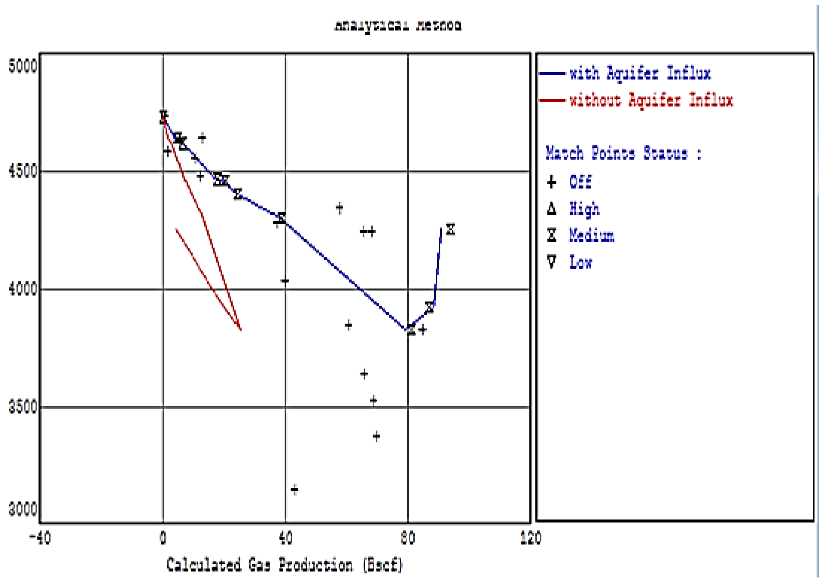


**Figure 5:** Akpet GT 9 Reservoir Analytical Plot

Figure 6 shows the simulation calculations which serve as a final quality check on the history matching done earlier (Figure 5). In the simulation run, the rates (Figure 7) are used from the historical data and the reservoir pressure is calculated based on the material balance model.

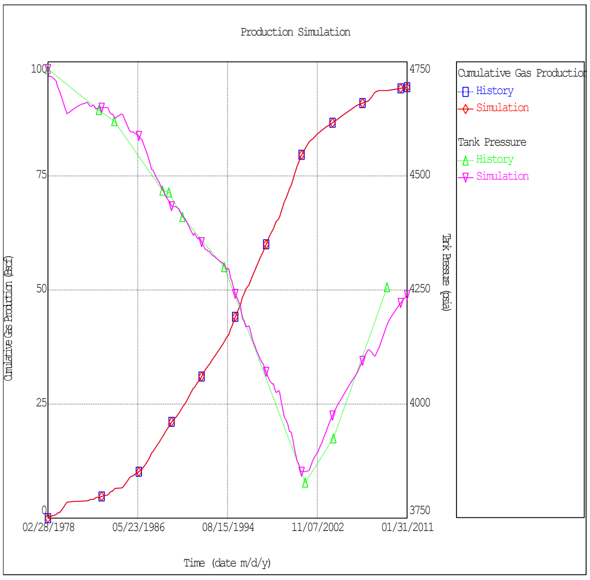


**Figure 6:** Akpet GT 9 Pressure History Match Plot

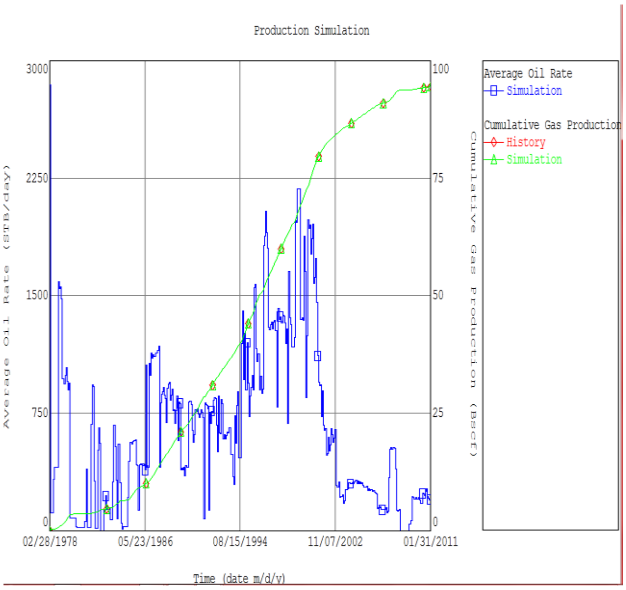


**Figure 7:** Akpet GT 9 reservoir cumulative gas produced and average oil rate

## CONCLUSIONS

The following conclusion where drawn from the observations of the results from the study:

- The result obtained with MBal on the analysis of Akpet GT 9 reservoir show that the most likely aquifer model is the Hurst–Van Everdingen - Dake radial aquifer and the reservoir is supported by a combined drive of water influx and fluid expansion.
- The modified form of the material balance equation could be used to predict changes in produce fluid compositions as a function of production, and to accurately predict the gas and gaseous equivalence initially in place, recovery factor and hence reserves.
- The MBAL approach proves to be sufficient for modeling gas condensate behavior below the dew point. The MBAL simulation model can adequately simulate the depletion and water influx processes for gas condensate reservoirs. Using the MBAL approach, instead of a fully compositional approach, may result in significant time saving especially in full-field simulation studies. Partial pressure maintenance operational scheme should be carried out to produce more condensate liquids to minimize condensate fluid loss to the reservoir.
- History Matching must not be achieved at the expense of parameter modifications that are physically and/or geologically wrong. Moreover, the prediction cases should not exceed capabilities of the model and must be consistent with field practices.

## REFERENCES


Ahmadi, M., Sharifi, M. and Hashemi, A. (2014). Comparison of Simulation Methods in Gas Condensate Reservoirs. *Petroleum Science and Technology*, 32(7): 761-771.doi: 10.1080/10916466.2011.604063

Babalola, F. U., Susu, A. A, Olaberinjo, F. A. (2009a). Gas Condensate Reservoir Modeling, Part I: From Deterministics To Stochastics. *Petroleum Science and Technology*, 27(10): 1007-1013. doi: 10.1080/10916460802455681

Babalola, F. U., Susu, A. A, Azom, P. N. (2009b). Gas Condensate Reservoir Modeling, Part II: Development of a Stochastic Model. *Petroleum Science and Technology*, 27(14): 1545-1554. doi: 10.1080/10916460802608545

Cho, S. J., Civan, F.and Starling, K. E. (1985). A Correlation To Predict Maximum Condensation for Retrograde Condensation Fluids and Its Use in Pressure-Depletion Calculations. Presented at the SPE Annual Technical Conference and Exhibition, Las Vegas, USA, 22-25. SPE 14268. doi:10.2118/14268-MS

Thomas, F. B., Bennion, D. B.and Andersen, G. (2009). Gas Condensate Reservoir Performance. *Journal of Canadian Petroleum Technology*, 48(7), 18-24. doi:10.2118/09-07-18.

Gringarten, A. C., Al-Lamki, A., Daungkaew, S., Mott, R.and Whittle, T. M. (2000). Well Test Analysis in Gas-Condensate Reservoirs. Presented at the SPE Annual Technical Conference and Exhibition, Dallas, Texas, USA, 1–4 October. SPE 62920. doi.org/10.2118/62920-MS.

Olaberinjo A. F. and Omole, O. O. (2004). A Compositional Approach for Calculating Pressure Depletion Performance of Gas condensate Reservoirs", PTDF Report Series 2004, Department Of Petroleum Engineering, University of Ibadan, Nigeria.