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KPIM of Gas/Condensate Productivity: Prediction of Condensate/Gas Ratio Using Reservoir Volumetric Balance

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Abstract: A new approach for forecasting viability of gas condensate wells and calculating Condensate Gas Ratio (CGR), using simpler techniques is presented. The calculation uses a volumetric balance model for reservoir system, standardized and modified correlations, equation of state and a vapor-liquid equilibrium technique. The technique has been extended to include mass transfer and also to allow for the changes in produced fluid composition due to the formation of the condensate bank. The approach will provide a useful tool for rapid forecasts of condensate well performance, for examining the effects of condensate blockage in different well types or for studying sensitivities. It is also valuable where simple models of condensate reservoir performance are required for use in integrated studies.

Key words: Forecasting, condensate, deliverability, drilling, reservoir, correlation, equilibrium

INTRODUCTION

Gas condensates are becoming exceptionally important throughout the world. Two common areas are of specific interest-characterization and retrograde condensation influences on the properties of gas condensate mixtures.

Retrograde condensation in gas condensate reservoirs and gas liberation in volatile oil reservoirs are examples of two phase flow problems currently attracting interest. In simulating such flows, knowledge of the mutual influences between the flow of the reservoir fluid and the thermodynamics of the equilibrium is essential. The term retrograde condensation is used to describe the anomalous behavior of a mixture that forms a liquid by isothermal decrease in pressure or by an isobaric increase in temperature.

In many gas condensate reservoirs well productivity has a major impact on development and operational decisions such as the number of wells, whether to fracture wells, the size of surface facilities and the level of gas sales contracts. From economic point of view, reservoir development and management decisions must be taken in the presence of a number of uncertainties. Condensate blockage and its impact on well productivity is just one of the uncertainties.

The uncertainty in gas-condensate well productivity can be reduced by considering a number of factors such as: mass transfer effect, interfacial tension, viscosity ratio, number of moles of liquid and vapor at equilibrium, Condensate Gas Ratio (CGR), compositional changes and the healing of fractures with its concomitant effect on absolute permeability.

Understanding multiphase flow in condensate reservoirs is paramount in characterizing condensate dropout and subsequent blockage effect. Fevang and Whitson (1995) presented an accurate yet simple model of a gas-condensate well undergoing depletion which consists of three flow regions-Region 1: An inner near-wellbore region where both gas and liquid flow simultaneously, Region 2: A region of condensate buildup where only gas is flowing. Region 3: A region containing single-phase (original) reservoir gas. This region is the farthest away from the well.

Fevang and Whitson (1995) in their studies showed that, when reservoir pressure around a well drops below the dew point pressure, retrograde condensation occurs and three regions are created with different liquid saturations as shown in Fig. 1.

Other areas of gas condensate concern were dealt with by other authors; Thomas *et al.* (1995) worked on optimizing production from a gas condensate reservoir.

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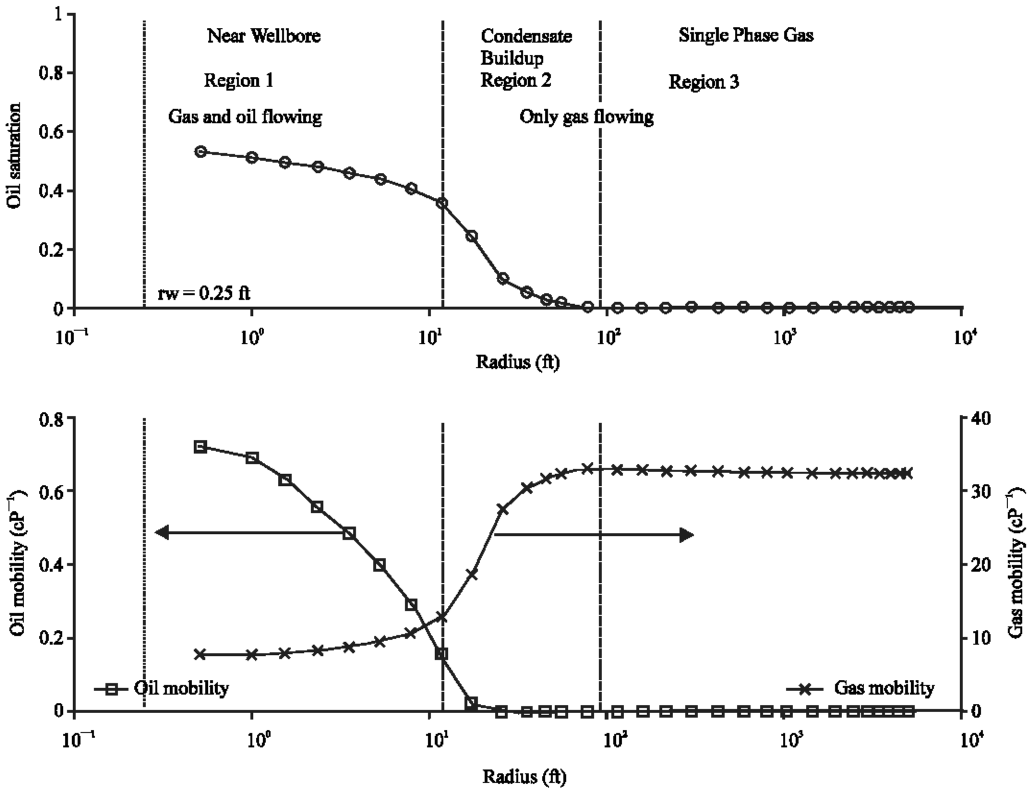

Fig. 1: Schematic gas condensate flow regimes (Fevang and Whitson, 1995)

Their research seeks to describe some of the phenomena that are at work in rich gas condensate reservoirs. In this context, specific parameters such as interfacial tension, mobility effects, pore size distribution and compositional changes are important in the optimization of gas condensate wells.

Cable *et al.* (2002) considered issues affecting gas condensate production and how special core analysis data for near-well relative permeability may be used to model productivity in a full field model for evaluating gas condensate reservoir development. They argue that though some aspects of gas condensate reservoir can be studied using standard techniques from dry gas reservoir engineering, it is also important to consider issues such as liquid recovery and change in yield during field life, compositional gradients and the reduction in well deliverability caused by condensate blockage.

In furtherance to gas condensate productivity studies, Mott (2002) reviewed recent developments in the understanding of near-well behaviour in condensate reservoirs and in estimating well productivity through numerical simulation. Three different approaches for calculating condensate well productivity in full field reservoir simulation were considered-using single well calculations to estimate skin factors, local grid refinement and pseudopressure methods.

Sognesand (1991) discussed the condensate build up in vertical fractured gas condensate wells. He showed that the condensate build up depends on the relative permeability characteristics and production mode, increased permeability to gas yields reduced amount of condensate accumulation and constant pressure production yields the largest near fracture condensate buildup.

Cho *et al.* (1985) presented a correlation to predict maximum condensation for retrograde condensation fluids and its use in pressure depletion calculations. The correlation presented is a function of the reservoir temperature and the heptanes plus mole fraction.

Based on the above, Olaberinjo and Omole (2004) presented a reasonably systematic and inexpensive compositional approach for calculating pressure depletion performance of gas condensate reservoirs with consideration to the properties of liquid and vapor phase with possible presence of impurities-CO_2, H_2S and S.

Furthermore, the impact of condensate blockage is very sensitive to the gas-oil relative permeabilities in the region around the wellbore. Several laboratory experiments have demonstrated an increase in mobility for gas-condensate fluids at the high velocities typical of the near-well region, a mechanism that would reduce the negative impact of condensate blockage. There is also some evidence from well test results to suggest that this effect occurs in the field (Olaberinjo, 2006).

Despite a large number of reported studies on gas condensate reservoirs, in addition to those cited here, non of it considered calculations of gas condensate reservoir performance and productivity with accurate knowledge of the volumetric behavior of hydrocarbon mixtures, both liquid and vapor and other key properties like compressibilities of the two-phase which are required in the transient fluid flow problems and thermal expansion coefficients which are important in thermal method of production.

This research focused basically on forcasting the viability and performance of gas condensate reservoir (constant volume depletion calculations and estimation of condensate gas ratios close to the well bore) using reservoir volumetric balance. The approach is economical, reliable and less cumbersome.

MATHEMATICAL FORMULATIONS

Considering the inner near-wellbore region where both gas and liquid flow simultaneously at different velocities (Fig. 1) in this region oil mobility and saturation increases hence a two phase flow exists. The total volume of fluid flowing in this region can be given as follows:

Total Volume of Gas Condensate in Place = Volume of Condensate + Volume of Vapor

$$V_{FLUID} = V_{CONDENSATE} + V_{VAPOR}$$

The above volumetric balance can be represented as

$$V_{GASCON} = V_C + V_V \tag{1}$$

Differentiating in turn with special consideration to Pressure and Temperature,

$$\left(\frac{\partial V_{GASCON}}{\partial P}\right)_T = \left(\frac{\partial V_C}{\partial P}\right)_T + \left(\frac{\partial V_V}{\partial P}\right)_T \tag{2}$$

Also,

$$\left(\frac{\partial V_{GASCON}}{\partial T}\right)_P = \left(\frac{\partial V_C}{\partial T}\right)_P + \left(\frac{\partial V_V}{\partial T}\right)_P \tag{3}$$

It is important to choose accurate expressions relating V_C to the independent variables which permit greater accuracy in obtaining values for Eq. 2 and 3. Considering the isothermal compressibility, c

$$c = -\frac{1}{V}\left(\frac{\partial V}{\partial P}\right)_T \tag{4}$$

The coefficient of isobaric thermal expansion, β is also given as:

$$\beta = \frac{1}{V}\left(\frac{\partial V}{\partial T}\right)_P \tag{5}$$

From the equations above, the following expressions for compressibility and thermal expansion coefficient, respectively, can be written for a gas condensate reservoir system.

$$-\frac{1}{V_{GASCON}}\left(\frac{\partial V_{GASCON}}{\partial P}\right)_T = -\frac{1}{V_C + V_V}\left\{\left(\frac{\partial V_C}{\partial P}\right)_T + \left(\frac{\partial V_V}{\partial P}\right)_T\right\} \tag{6}$$

$$\frac{1}{V_{GASCON}}\left(\frac{\partial V_{GASCON}}{\partial T}\right)_P = \frac{1}{V_C + V_V}\left\{\left(\frac{\partial V_C}{\partial T}\right)_P + \left(\frac{\partial V_V}{\partial T}\right)_P\right\} \tag{7}$$

Employing Surjit and Kennedy (1968) approach with sound modifications in terms of reduction in the number of constants, variables and considering pseudo component system-Light (C_1), Intermediate (C_2-C_6) and Heavier (C_{7+}) and also giving critical considerations to mass transfer effects and vapor-liquid equilibrium of the system (separate mole fractions of the components); we have for condensate and vapor fraction volumes, respectively:

CONDENSATE (LIQUID) VOLUME, V_C

$$V_C = V_{REF} - \ln\left\{\begin{array}{l} D_O + D_1\left(\dfrac{xC_1}{1.01 - xC_1}\right) + D_2\left(\dfrac{xC_1}{1.01 - xC_1}\right)^2 \\ +D_3\left(\dfrac{xC_1}{0.01 + xC_{7+}}\right) + D_4\left(\dfrac{xC_1}{0.01 + xC_{7+}}\right)^2 \\ +D_5\left(\dfrac{xC_{2-6}}{1.01 - xC_{2-6}}\right)^{1/2} + D_6\left(\dfrac{xC_{2-6}}{1.01 - xC_{2-6}}\right)^{1/4} \\ +D_7\left(\dfrac{xC_{2-6}}{1.01 - xC_{2-6}}\right)^{1/2} + D_8\left(\dfrac{xC_{2-6}}{1.01 - xC_{2-6}}\right)^{1/4} + \\ D_9\left(0.9(xC_1) + (1.1xC_{7+}) - 1.2(xC_{2-6})\right) + \\ D_{10}\left(0.9(xC_1) + (1.1xC_{7+}) - 1.2(xC_{2-6})\right)^{1/4} + \\ D_{11}\left(0.9(xC_1) + (1.1xC_{7+}) - 1.2(xC_{2-6})\right)^2 \\ +D_{12}M_{C7+} + D_{13}\rho_{C7+} + D_{14}\ln(\rho_{C7+} + 0.01) \\ +D_{15}(M_{C7+} * \rho_{C7+}) + D_{16}(M_{C7+} * \rho_{C7+})^2 + \\ D_{17}\left(\dfrac{xC_{7+} * T}{(M_{C7+} * \rho_{C7+}) + 0.01}\right) + D_{18}T + D_{19}P \end{array}\right\} \tag{8}$$

Equation 8 can be differentiated to calculate compressibilies and the thermal expansion coefficients of condensate (liquid) fraction (Appendix A)

Hence, differentiating with respect to pressure yields:

$$\left(\frac{\partial V_C}{\partial P}\right)_T = \left(\frac{\partial V_{REF}}{\partial P}\right)_T - \left[\left(\exp\left(V_C - V_{REF}\right)\right) * D_{19}\right] \tag{9}$$

Differentiating Eq. 8 with respect to temperature yields the following expression:

$$\left(\frac{\partial V_C}{\partial T}\right)_P = \left(\frac{\partial V_{REF}}{\partial T}\right)_P - \left[\begin{array}{l}\left(\exp\left(V_C - V_{REF}\right)\right) \\ *D_{17}\dfrac{xC_{7+}}{\left(M_{C7+} * \rho_{C7+}\right) + 0.01} + D_{18}\end{array}\right] \tag{10}$$

VAPOR VOLUME, V_V

$$V_V = V_{REF(V)} - \ln\left\{\begin{array}{l}
B_0 + B_1\left(\frac{yC_1}{1.01-yC_1}\right)^2 + B_2\left(\frac{yC_1}{1.01-yC_1}\right)^3 \\
+B_3\left(\frac{yC_1}{1.01-yC_1}\right)^4 + B_4\left(6yC_{2-6}\right)^{1/2} \\
+B_5\left(yC_{7+}\right) + B_6\left(\frac{yC_1}{0.01+yC_{7+}}\right) + \\
B_7\left(\frac{yC_1}{0.01+yC_{7+}}\right)^2 + B_8\left(\frac{yC_{2-6}}{1.01-yC_{2-6}}\right) + \\
B_9\left(\frac{yC_{2-6}}{1.01-yC_{2-6}}\right)^{1/2} + B_{10}\left(1.1yC_1 + 1.2yC_{2-6}\right) + \\
B_{11}\rho_{C7+}B_{12}\left[\left(\frac{yC_{7+}*M_{C7+}}{50.0}\right)*\left(1.0+\frac{2}{0.01+\rho_{C7+}}\right)\right] + \\
B_{13}\left[\left(\frac{yC_{7+}*M_{C7+}}{50.0}\right)*\left(1.0+\frac{2}{0.01+\rho_{C7+}}\right)\right]^2 + \\
B_{14}\left[\left(\frac{yC_{7+}*M_{C7+}}{50.0}\right)*\left(1.0+\frac{2}{0.01+\rho_{C7+}}\right)\right]^{1/2} + \\
B_{15}\left[\frac{\ln\left[\left(yC_{7+}*T*10^{-2}\right)+0.01\right]}{\left(M_{C7+}*\rho_{C7+}\right)+0.01}\right] + B_{16}T^{1/2} + \\
B_{17}\frac{T}{P} + B_{18}\left(T*\ln\left(P*10^{-3}\right)\right) + B_{19}\left(P*\ln\left(T*10^{-2}\right)\right)
\end{array}\right\} \tag{11}$$

Equation 11 can be differentiated to calculate compressibilities and thermal expansion coefficients of the vapor fractions (Appendix A).

Appendix A:

Coefficients for Equations 8

D_0	$0.35568804*10^{2}$	D_{10}	$0.47097391*10$
D_1	-0.13527706	D_{11}	$0.15158952*10$
D_2	$0.92788640*10^{-1}$	D_{12}	$-0.25714342*10^{-1}$
D_3	0.14113548	D_{13}	$-0.37107261*10^{2}$
D_4	$-0.32315277*10^{-1}$	D_{14}	$0.27414938*10^{2}$
D_5	$-0.10549435*10$	D_{15}	$0.30740710*10^{-1}$
D_6	$0.10252432*10$	D_{16}	$-0.52353616*10^{-5}$
D_7	0.51822466	D_{17}	$-0.74618823*10^{-2}$
D_8	-0.49754594	D_{18}	$-0.56509643*10^{-4}$
D_9	$-0.48125456*10$	D_{19}	$-0.51760612*10^{-5}$

Coefficients for Equations 11

B_0	$0.13530821*10$	B_{10}	-0.28777369
B_1	$0.19848504*10^{-2}$	B_{11}	-0.30461668
B_2	$-0.19844088*10^{-3}$	B_{12}	-0.81160977
B_3	$0.51379175*10^{-5}$	B_{13}	$0.94223921*10^{-1}$
B_4	$0.24836420*10^{-1}$	B_{14}	0.32539924
B_5	$0.44694647*10$	B_{15}	$0.30306454*10$
B_6	$-0.14129608*10^{-2}$	B_{16}	$0.10854281*10^{-1}$
B_7	$0.34589052*10^{-4}$	B_{17}	-0.33153892
B_8	-0.12601651	B_{18}	$-0.15405355*10^{-3}$
B_9	0.12378339	B_{19}	$0.52470355*10^{-5}$

Differentiating with respect to pressure yields:

$$\left(\frac{\partial V_V}{\partial P}\right)_T = \left(\frac{\partial V_{REF(V)}}{\partial P}\right)_T + \left[\begin{array}{l}\left(\exp\left(V_V - V_{REF(V)}\right)\right)* \\ \left(\begin{array}{l}B_{17}\dfrac{T}{P^2} - B_{18}\dfrac{T}{P} - \\ B_{19}\ln\left(T*10^{-2}\right)\end{array}\right)\end{array}\right] \tag{12}$$

Differentiating with respect to temperature yields:

$$\left(\frac{\partial V_V}{\partial T}\right)_P = \left(\frac{\partial V_{REF(V)}}{\partial T}\right)_P - \left[\left(\exp\left(V_V - V_{REF(V)}\right)\right)\right]* \\ \left[\begin{array}{l}B_{15}\dfrac{yC_{7+}*10^{-2}}{\left(\left(yC_{7+}*T*10^{-2}\right)+0.01\right)*\left(\left(M_{C7+}*\rho_{C7+}\right)+0.01\right)} + \\ B_{16}\dfrac{T^{-1/2}}{2} + B_{17}\dfrac{1}{P} + B_{18}\ln\left(P*10^{-3}\right) + B_{19}\dfrac{P}{T}\end{array}\right] \tag{13}$$

Where V_{REF} and $V_{REF(V)}$ are reference volumes for the condensate and vapor respectively and can be determined using Eq. 14.

$$\begin{array}{l}V^3 - \left(\dfrac{RT}{P} + mT + C\right) \\ V^2 + \dfrac{Ke^{\frac{n}{T}}}{P}V - \dfrac{Ke^{\frac{n}{T}}}{P}\left(mT + C\right) = 0\end{array} \tag{14}$$

Equation 14 provides functional relationships between pressure, temperature, volume and composition in a fluid system. In vapor-liquid equilibrium calculations, it is a common practice to use a single equation of state for liquid and vapor. The equation is usually cubic in volume where the smallest root is chosen for liquid and the largest for vapor.

ANALYSIS OF RESULTS

From practical point of view, the liquid phase viscosity, molal density and volume affect the pressure. The liquid phase fraction determines the response of a gas condensate system. The gas deviation factor, viscosity and the formation volume factor (B_g) are functions of pressure only in situ, although the deviations are usually small. The leaner the retrograde gas, the smaller the deviations.

Table 1 shows the two cases considered-Rich Gas Condensate Reservoir and Lean Gas Condensate Reservoir. The predicted liquid molal volume (Fig. 2), isothermal compressibility and the liquid phase density were calculated based on the liquid phase composition in the overall mixture. Figure 3 shows the variation of vapor phase compressibility factor with pressure.

Equation 15 and 16 established that the flow coefficient of gas phase to oil phase which depends greatly on pressure is equal to the ratio of the total moles of vapor to liquid hence the justification of the reservoir volumetric balance in the determination of the constant volume depletion of gas condensate reservoir.

$$\frac{V}{L} = \frac{l_g}{l_o} = f(P) \tag{15}$$

where l_g and l_o are flow coefficient of gas and oil phase, respectively.

$$\frac{l_g}{l_o} = \frac{K_{rg}\rho_g\mu_o}{K_{ro}\rho_o\mu_g} \tag{16}$$

For gas condensate with low dropout, the change in pressure difference with time is not significant since the flow coefficient of gas phase to oil phase and relative permeability to gas is considerably high. Unlike in the case of a gas condensate with high liquid dropout where retrograde condensations impairs the relative permeability to gas.

Table 1: Gas condensate feed composition

Component	Mole %-Rich gas condensate	Mole %-Lean gas condensate
C_1 (Light)	58.77	73.190
C_2.C_6 (Intermediate)	18.33	15.920
C_{7+} (Heavier)	21.76	08.210
N_2	00.21	00.310
CO_2	00.93	02.370
Total mole	100.00	100.000

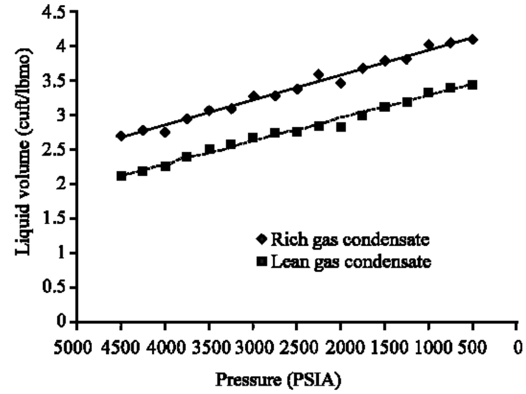

Fig. 2: Pressure variation with molal volume of liquid

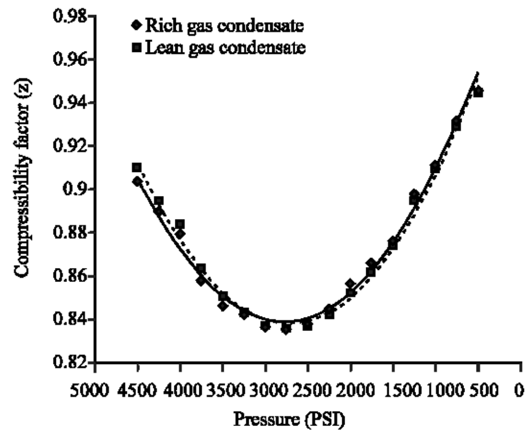

Fig. 3: Variation of pressure with vapor phase compressibility factor, z

Increase reservoir pressure increases the gas condensate viability and productivity. Figure 4 shows significant productivity loss due to condensate richness. The productivity loss also depends on the relative permeability characteristics, the production mode and most especially the initial reservoir pressure. The total flow rate decreases with decrease in pressure as a result of liquid hold-up.

Figure 5 shows the plot of estimated Condensate Gas Ratio (CGR) to a vertical well. The change in CGR is due to the loss of oil in Region 2 as the condensate bank builds up.

Comparatively, constant volume depletion calculations for retrograde condensate fluid for Cho *et al.* (1985), Firoozabadi (1985) and the one predicted by Olaberinjo *et al.* (2000) 1(New Approach), shows good agreement between predicted values and experimental values. Figure 6 presents the plot of the three methods above, they made use of percentage mole of C_{7+} in their correlation while the new approach take into consideration C_1 (Light), C_2-C_6(Intermediate) and C_{7+} (Heavier).

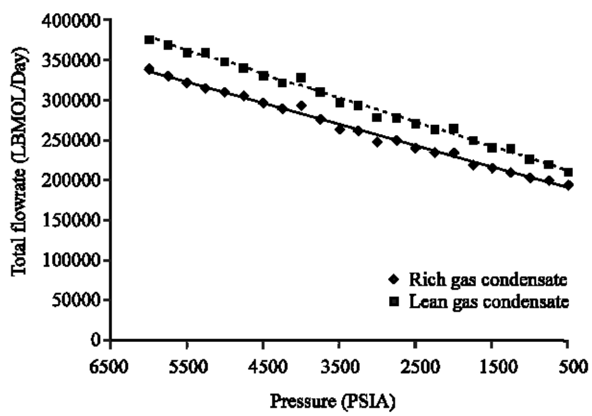

Fig. 4: Variation of pressure (PSI) with total flowrate, qt (lbmol/day)

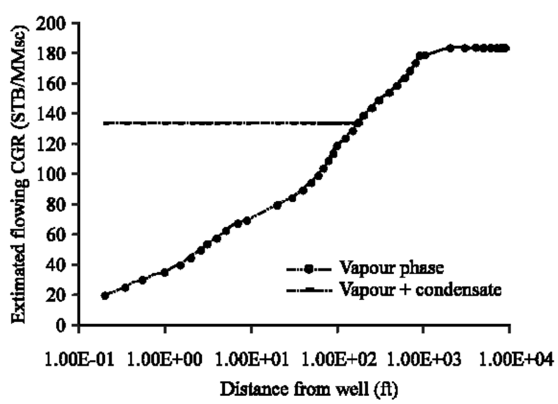

Fig. 5: Extimated flowing condensate-gas ratio to a vertical well

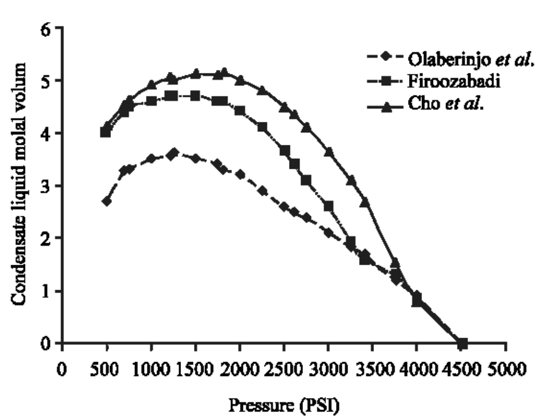

Fig. 6: Constant volume depletion calculation for retrograde condensate fluid - condensate yield versus pressure

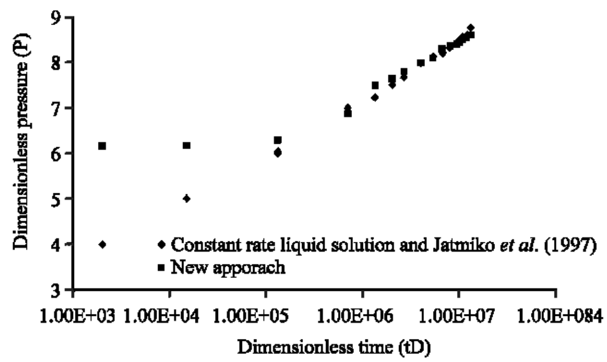

Fig. 7: Dimensionless pseudopressure, pd and dimensionless time, td for qt = 50000 lbm/d and k = 100 md

The adopted reservoir volumetric approach expresses molal volume of retrograde liquid with considerably greater accuracy than methods of prediction presently available and applies over wider ranges of the variables involved.

Figure 7 show that the dimensionless wellbore pseudopressure response calculated by constant rate liquid solution method and Jatmiko *et al.* (1997) approach. This agrees considerably with the new approach with percentage deviation of about -8.64. The deviation in the slope between the pseudopressure and the liquid solution measures the error in the permeability estimation using the pseudopressure and the vertical shift measures the error in the skin estimation.

CONCLUSIONS

This research formulate a better method for determining the constant volume depletion calculations for retrograde condensate fluid and also for calculating accurately the volumes, compressiblities and thermal expansion coefficients of both liquid and vapor components of a gas condensate system which are highly essential in gas condensate reservoir performance and productivity analysis.

The approach expresses molal volume of retrograde liquid with considerably greater accuracy than methods of prediction presently available and applies over wider ranges of the variables involved.

Nomenclature

c Compressibility, Psia^{-1}
M Molecular weight, lbm/lbmol
P Reservoir pressure, psia
R Universal gas constant, 10.73 (Psia ft^3/mol R)
T Formation temperature °F

Z Gas compressibility factor
ρ Density, lbm/ft^3
μ Viscosity, cp
x Liquid composition
y Vapor composition
L Mole fraction of liquid
V Mole fraction of vapor

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