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PREDICTION OF FLOWING BOTTOMHOLE PRESSURE IN GAS-CONDENSATE WELLS

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ABSTRACT

Bottom-hole pressures in gas and condensate wells are frequently measured at a great cost and with operational challenges. On the other hand, most analytical estimation procedures either use trial and error or neglect liquid holdup in condensate wells. Using the mechanical energy balance approach, an approximate model was developed to estimate bottom-hole pressure from wellhead pressures in condensate wells without neglecting liquid holdup. The results show that treating gas condensate like dry gas wells lead to over prediction (10-15%) of flowing bottom-hole pressures, with serious consequences on phase behaviour, reservoir characterization and production management.

Keywords: Gas Condensate Wells, Flowing Bottom-hole Pressure, Analytical Model, Gas Wells, Energy balance

NOMENCLATURE

A – Cross sectional area of pipe, ft^2
B – Formation volume factor, bbl/stb
D – Inside diameter of pipe, inches
dp – Pressure differential, ib/ft^3
E – Parameter as defined by equation 11
f – Moody friction factor
F – Parameter as defined by equation 13
g – Acceleration due to gravity, ft/sec^2
G – Parameter as defined by equation 13
g_c – Conversion factor, 32.17 ibmft/ibfs
H – Liquid holdup
h – Volume fraction in the liquid, ft^3

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L – Vertical length of flow string, ft
P – Pressure, psia
q – Volumetric flowrate, ft^3/sec
R_s – Gas-oil ratio, scf/stb
T – Temperature, °R
u – Average velocity of fluid, ft/sec
X – Parameter as defined by equation 7
Z – Gas compressibility
$\aleph$ – Parameter as defined by equation 11
ρ – Density, ibm/ft^3
ψ_i – Parameter as defined by equation 14
Φ_i – Parameter as defined by equation 9
γ – Specific gravity

Subscripts

g – gas
L – liquid
m – mixture
o – oil
pr – pseudo-reduced
r – reduced
s – solution
tp – two-phase
w – water
wf – flowing bottom-hole
wh – well head
i – 1, 2, 3... 9

INTRODUCTION

Gas condensate reservoirs are becoming more predominant as petroleum exploration goes into greater depths with high temperatures and pressures. Understanding the phase behaviour in condensate systems and reservoir conditions such as pressure is essential for accurate engineering computations and management.

When pressure falls below the dew point, condensate formation begins and accumulates at the wellbore forming condensate bank and resulting in substantial reduction in well productivity. Thus, as observed by Porter (1992), flowing bottom-hole pressure is very crucial not only at very early in the life of a well but throughout the production life. Onyeizugbe and Ajienka (2010) have noted that real time production of bottom-hole pressure is key to achieving real time monitoring of well performance.

Guo (2001) stated that knowledge of bottom-hole pressure (BHP) is essential for determining inflow performance relationship (IPR) in wells. Bottom-hole pressures are therefore measured using down-hole pressure gauges but the measurements are costly and time consuming. Wellhead measurements if used are not expensive and readily available. However, a reliable relationship between wellhead and bottom-hole pressure is needed for accurate estimation of the BHP.

Early researchers such as Al Hussainy and Ramey (1966) and Al Hussainy et al., (1966) tended to treat gas condensate reservoirs like single-phase gas. The results obtained from such simplified assumptions can be misleading in reservoirs with significant liquid drop-out. The use of two-phase steady state pseudopressure model was first introduced by O'Dell and Miller (1967) and later enhanced by Fussel (1973), Chopra and Carter (1985) and Jones et al. (1989). The two-phase pseudopressure is expected to give more accurate estimates in condensate reservoirs.

Direct measurements using permanent down-hole gauges are very expensive while the use occasional pressure bombs are not amenable to real time performance monitoring. One of the earliest analytical models developed in predicting flowing bottom-hole pressure (FBHP) in gas wells was by Sukkar and Cornell (1955). The model uses the mechanical energy balance method and is fairly accurate for dry gas. Other researchers such as Beggs (1991) and Cullender and Smith (1996) have tried to improve on the predictions. However, these methods do not account for liquid holdup in gas wells. The work of Adekomaya et al. (2008) was not conclusive and cannot be easily applied. Onyeizugbe and Ajienka (2010) used data from wells in the Niger Delta to develop a correlation for real time prediction of flowing bottom-hole pressure in oil and gas wells. However, while the correlation could be applied to oil, gas and water producers, it cannot be used for condensate wells. This current study extended the Sukkar and Cornell direct approach for estimating flowing bottom-hole pressure by incorporating liquid holdup in condensate wells.

THEORETICAL FRAMEWORK

The analytical expressions developed were based on the following assumptions: Change in kinetic energy is negligible, constant average temperature of the system, constant friction losses over the length of the conduit.

The fundamental mechanical energy equation for steady-state flow is expressed as:

$$\frac{144}{\rho}dp + \frac{Udu}{2\alpha g_c} + \frac{g}{g_c}dz + \frac{fu^2}{2g_c D}dL + W_s = 0 \tag{1}$$

In reduced form equation (1) becomes:

$$\frac{144}{\rho}dp + \frac{g}{g_c}dz + \frac{fu^2}{2g_c D}dL = 0 \tag{2}$$

The average multiphase fluid density by the "mixing" is given by:

$$\rho_{tp} = \rho_L H_L + \rho_g (1 - H_L) \tag{3}$$

The density of liquid (oil and water) is given by:

$$\rho_L = \rho_o h_o + \rho_w h_w \tag{4}$$

or

$$\rho_L = \left(\frac{62.4\gamma_o + 0.0136\gamma_g R_s}{B_o} \right) h_o + \frac{62.4\gamma_w h_w}{B_w} \tag{5}$$

The two-phase density can thus be expressed as:

$$\rho_{tp} = \left\{ \frac{(62.4\gamma_o + 0.0136\gamma_g R_s) h_o}{B_o} + \frac{62.4\gamma_w (1 - h_o)}{B_w} \right\} H_L + \frac{28.97 P\gamma_g (1 - H_L)}{ZRT} \tag{6}$$

or

$$\rho_{tp} = XH_L + \frac{28.97 P\gamma_g (1 - H_L)}{ZRT} \tag{7}$$

where,

$$X = \frac{(62.4\gamma_o + 0.0136\gamma_g R_s) h_o}{B_o} + \frac{62.4\gamma_w (1 - h_o)}{B_w}$$

Gas constant, R is 10.73.
The velocity, of fluid flow at a cross section of a vertical pipe is defined as:

$$U_m = \frac{0.4152 q_g TZ}{PD^2} + \frac{0.000082735 B_o q_L}{D^2} \tag{8}$$

Substituting equations (7) and (8) into equation (2) and expanding, we have: using the approach by Adekomaya et al. gives:

$$\left(1 + \Phi_1 \left(\frac{Z}{P} \right)^2 + \Phi_2 B_o \left(\frac{Z}{P} \right) + \Phi_3 B_o^2 \right) dL = \frac{-144 dP}{\left(XH_L + \frac{2.70 P\gamma_g (1 - H_L)}{ZT} \right)} \tag{9}$$

where,

$$\Phi_1 = \frac{667 f q_g^2 T^2}{D^5}, \Phi_2 = \frac{0.26571 f q_g q_L T}{D^5}, \Phi_3 = \frac{26473\times10^{-9} f q_L^2}{D^5}$$

Integrating equation (9) and simplifying gives:

$$\frac{0.01875\gamma_g L}{\bar{T}} = \int \frac{dP}{\left(1+\Phi_1\left(\frac{Z}{P}\right)^2 + \Phi_2 B_o\left(\frac{Z}{P}\right) + \Phi_3 B_o^2\right)\left(\frac{XH_L\bar{T}}{2.7\gamma_g} + \frac{P(1-H_L)}{Z}\right)} \tag{10}$$

or,

$$\frac{0.01875\gamma_g L}{\bar{T}} = \int_{P_{rwh}}^{P_{rwf}} \frac{\frac{Zdp_r}{P_r}}{(1+\Phi_1\aleph)(EH_L+1)} \tag{11}$$

where,

$$\aleph = \left(\left(\frac{Z}{P}\right)^2 + \Phi_5 B_o\left(\frac{Z}{P}\right) + \Phi_6 B_o^2\right), E = \left(\Phi_7\left(\Phi_8 + R_s + \Phi_9\left(\frac{B_o}{B_w}\right)\right)\frac{1}{B_o}\frac{Z}{P} - 1\right)$$

$$\Phi_5 = \frac{38.84}{\bar{T}}\left(\frac{q_L}{q_g}\right), \Phi_6 = \frac{39.69}{\bar{T}^2}\left(\frac{q_L}{q_g}\right)^2, \Phi_7 = 22.94h_o\bar{T}, \Phi_8 = \frac{\gamma_o}{\gamma_g}, \Phi_9 = \left(\frac{\gamma_w}{\gamma_g}\right)\left(\frac{1-h_o}{h_o}\right)$$

If we assume, $Z = 1 + mP_r$ (12)

Substituting equation (12) into equation (11) gives:

$$\frac{0.01875\gamma_g L}{\bar{T}} = \int_{P_{rwh}}^{P_{rwf}} \frac{\frac{(1+mP_r)dp_r}{P_r}}{(1+\Phi_1 F)(GH_L+1)} \tag{13}$$

where

$$F = \left(\left(\frac{(1+mP_r)}{P_r}\right)^2 + \Phi_5 B_o\left(\frac{(1+mP_r)}{P_r}\right) + \Phi_6 B_o^2\right)$$

$$G = \left(\Phi_7\left(\Phi_8 + R_s + \Phi_9\left(\frac{B_o}{B_w}\right)\right)\frac{1}{B_o}\frac{(1+mP_r)}{P_r} - 1\right)$$

Integrating (13) by partial fraction and simplifying gives:

$$\frac{0.01875\gamma_g L}{\bar{T}} = \ln\left(\frac{P_{rwf}}{P_{rwh}}\right)\left[1-\psi_1+\psi_2 Z^3\left(\frac{P_{rwh}}{P_{rwf}}\right)^2+\psi_3 Z^2\left(\frac{P_{rwh}}{P_{rwf}}\right)\right]\left[\left(\frac{P_{rwh}}{P_{rwf}}\right)\psi_4-\ln\left(\frac{P_{rwf}}{P_{rwh}}\right)\psi_5\right] \quad (14)$$

where,

$$\frac{0.01875\gamma_g L}{\bar{T}} = \ln\left(\frac{P_{rwf}}{P_{rwh}}\right)\left[Y_1(P_r)+Y_2(P_r)+Y_3(P_r)+Y_4(P_r)\right](H_L+1) \quad (15)$$

or,

$$\frac{0.01875\gamma_g L}{\bar{T}} = \ln\left(\frac{P_{rwf}}{P_{rwh}}\right)Y(P_r)(H_L+1) \quad (16)$$

$$P_{rwf} = P_{rwh} e^{\left(\frac{0.01875\gamma_g L}{\bar{T}Y(P_r)(H_L+1)}\right)} \quad (17)$$

Expanding equation (17) and neglecting higher order terms gives:

$$P_{wf} = P_{wh}\left(1+\frac{0.01875\gamma_g L}{\bar{T}Y(P_r)(H_L+1)}\right) \quad (18)$$

Equation (18) gives the bottom-hole pressure of gas condensate wells.

$$Y(P_r) = f\left(f, D, Q, B_o, R_s, P\right) \quad (19)$$

RESULTS AND DISCUSSION

Equation (18) is a new generalized expression for flowing bottom-hole pressure calculation and can be applied to both dry and condensate gas wells. The equation shows clearly that liquid holdup (H_L) causes a faster reduction in the flowing bottom-hole pressure of condensate than in gas wells and hence should not be neglected if accurate prediction is desired. Equations (18) and (19) also confirm the well known fact that flowing bottom-hole pressure is strongly dependent on $Y(P_r)$. In other words, flowing bottom-hole pressure depends on tubing size and properties, flow rate, fluid properties and the operating conditions.

Equation (18) was evaluated by applying it to 2 condensate wells and 1 dry gas well. Reservoir and well data are given in Tables 1 and 2. Constant average temperature was assumed. The results are shown in Figures 1-5.

Figure 1 gives the results for dry gas well with no liquid holdup compared with condensate well with liquid holdup.

The pressure profiles for both cases are different. Figure 2 shows a comparison of the present study with that of Sukkar and Cornell. Figures 3 and 4 show the comparison of the predicted flowing bottom-hole pressure with actual field data. Figure 5 shows comparison between present model at different values of liquid holdup with field data and some published models.

The plots show that the present model is an improvement of the existing correlations. Figure 5 also suggests that where there is insufficient data or dropout, H_L of 0.5 may be assumed, without much loss in accuracy. This is better than assuming the condensate well is like dry gas well with H_L=0.

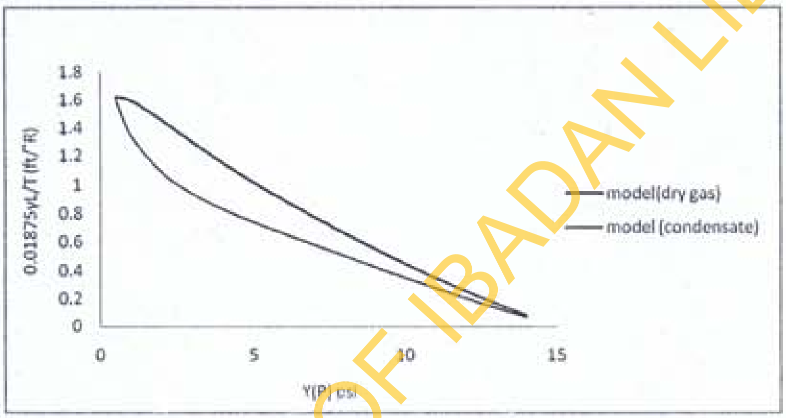

Figure 1. Bottom-hole Pressure for Dry Gas and Condensate Wells.

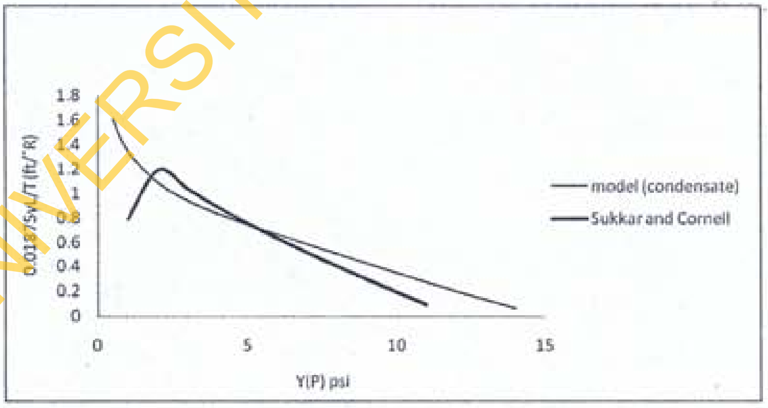

Figure 2. Comparison with Sukkar and Cornell Bottom-hole Pressure in a Condensate Well.

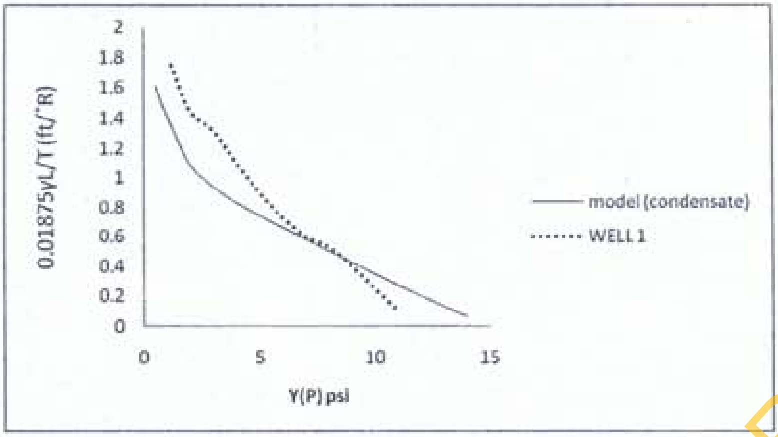

Figure 3. Bottom-hole Pressure Profile in Condensate Well 1.

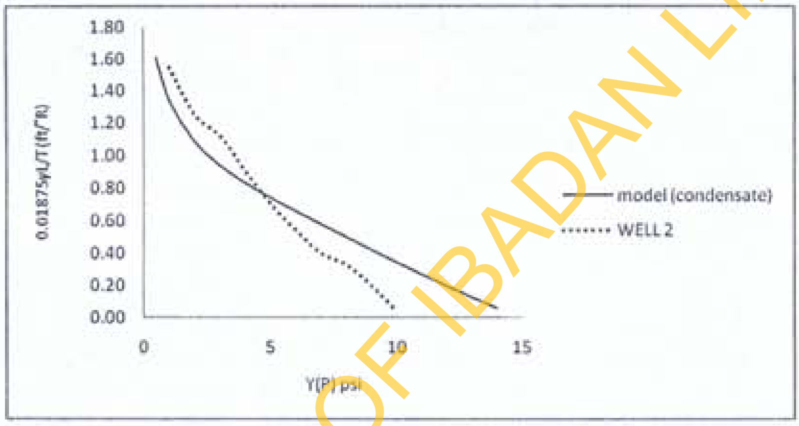

Figure 4. Bottom-hole Pressure Profile in Condensate Well 2.

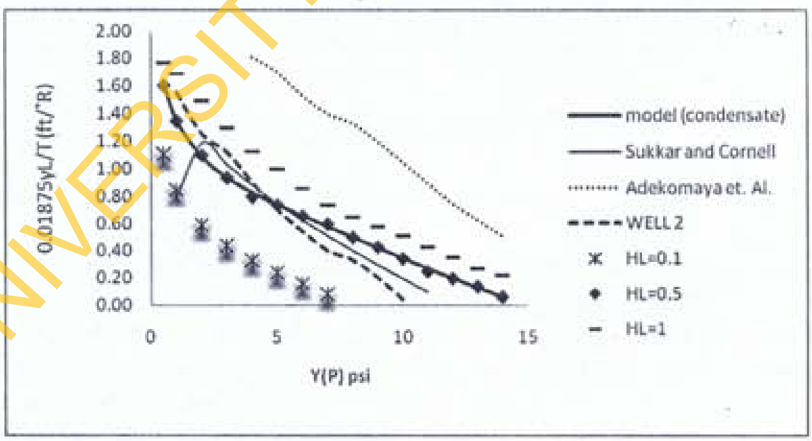

Figure 5. Comparison of present study with other models in a Condensate Well.

Table 1. Reservoir and Well Data

Parameter	Condensate Well 1	Condensate Well 2	Dry Gas Well
Gravity	0.75	0.73	0.57
M_a	21.61	21.01	16.62
P (psia)	5650	6000	4000
T (°R)	603	618	596
P_c (psia)	707	707	707
T_c (°R)	550	550	550
B_o	1.310	1.317	
B_w	1.004	1.003	1.000
R_s (scf/stb)	14,670	11,900	20,500
L (ft)	8,900	8,430	5,700
D (inches)	2.441	2.992	2.992
P_{wh} (psia)	1660	2315	3249

Table 2. Gas Composition

Component	Fraction		
	Condensate Well 1	Condensate Well 2	Dry Gas Well
C_1	0.8387	0.8516	0.9824
C_2	0.0531	0.0740	0.0039
C_3	0.0272	0.0133	0.0029
iC_4	0.0045	0.0104	0.0006
nC_4	0.0082	0.0033	0.0029
iC_5	0.0028	0.0051	0.0010
nC_5	0.0027	0.0022	0.0013
C_6	0.0031	0.0068	0.0010
C_{7+}	0.0024	0.0218	0.0003
N_2	0.0009	0.0038	0.0020
CO_2	0.0348	0.0770	0.0017

CONCLUSION

From this study the following conclusion can be reached:

1. The pressure profiles in condensate wells differ significantly from dry gas wells. Generally higher pressure drops are obtained in condensate wells.
2. Accounting for liquid hold-up is important in condensate wells. Where there is paucity of information on condensate-gas ratio, assuming a hold-up of 50% should be more realistic than a zero hold-up assumption.

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APPENDIX A

From equation (14), defining:

$$\psi_1 = \Phi_1\Phi_6 B_o^2 \quad \text{A1}$$

$$\psi_2 = \frac{\Phi_1}{2} \quad \text{A2}$$

$$\psi_3 = \Phi_1\Phi_5 B_o \quad \text{A3}$$

$$\psi_4 = \Phi_7\Phi_8 - \frac{\Phi_7\Phi_8}{B_o} - \frac{\Phi_7 R_s}{B_o} \quad \text{A4}$$

$$\psi_5 = \Phi_7 R_s - \frac{\Phi_7\Phi_9}{B_o} + 1 \quad \text{A5}$$

From equation (15), the following can be defined:

$$Y_1(P_r) = \left(\psi_1\psi_5 - \psi_5 - \psi_3\psi_5 Z^2\left(\frac{P_{r1}}{P_{r2}}\right)\right)\ln\left(\frac{P_{r2}}{P_{r1}}\right) \quad \text{A6}$$

$$Y_2(P_r) = \left(\psi_4 - \psi_1\psi_4\right)\left(\frac{P_{r1}}{P_{r2}}\right) \quad \text{A7}$$

$$Y_3(P_r) = \left(\psi_3\psi_4 Z^2 - \psi_2\psi_5 Z^3\right)\left(\frac{P_{r1}}{P_{r2}}\right)^2 \quad \text{A8}$$

$$Y_4(P_r) = \psi_2\psi_4\left(\frac{P_{r1}}{P_{r2}}\right)^3 \quad \text{A9}$$

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