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Comparative Analysis of Gas wellbore Deliverability models

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ABSTRACT: *The success of gas well performance often depends on the accurate measurement or estimation of the bottom hole pressures. Measurement can be accomplished by a descending probe or pressure gauges. Although use of pressure gauges may be a more desirable mode, it is nevertheless time consuming and costly. Several estimation of static and flowing bottom hole pressures require extensive analysis because techniques used in predicting the production performance of deviated gas wells via the bottom-hole pressure gauges are some-times error prone in different wellbores. Three methods are presented here for calculating bottom-hole pressures of dry gas wells (Average z and T method, Sukker and cornell method, cullendar and smith method). These methods were able to compute the static and flowing bottom-hole pressures to some degree of certainty in the Niger delta.*

The proposed methods were compared with each other and with the actual static and flowing bottom-hole pressures and a statistical analysis was computed for this models which included the root mean square errors.

The results of the study eventually showed that the sukker and cornel method is the most preferable for computing flowing bottom-hole pressures of deviated wells while the cullender and smith method is the most preferable for static bottom-hole pressures of vertical wells.

KEYWORDS –*Gas, bottom-hole, Pressure, static, flowing*

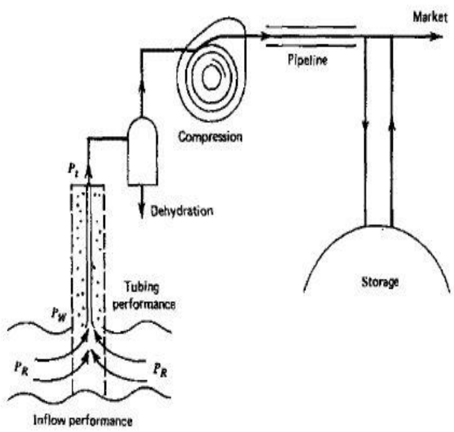
I. INTRODUCTION

Early estimates of gas well performance were conducted by opening the well to the atmosphere and then measuring the flow rate. Such "open flow" practices were wasteful of gas, sometimes dangerous to personnel and equipment, and possibly damaging to the reservoir. They also provided limited information to estimate productive capacity under varying flow conditions. The idea, however, did leave the industry with the concept of absolute open flow (AOF). AOF is a common indicator of well productivity and refers to the maximum rate at which a well could flow against a theoretical atmospheric backpressure at the reservoir.

The productivity of a gas well is determined with deliverability testing. Deliverability tests provide information that is used to develop reservoir rate-pressure behavior for the well and generate an inflow performance curve or gas-backpressure curve. The ability of this reservoir to deliver a certain quantity of gas depends both on the inflow performance relationship and the flowing-bottom-hole pressure.

In order to determine the deliverability of the total well system, it is necessary to calculate all the parameters and pressure drops.

Well, the static and flowing pressure at the formation must be known in order to predict the productivity or absolute open flow potential of gas wells. The preferred method is to measure the pressure with a bottom-hole pressure gauge. It is often impractical or too expensive to measure static or flowing bottom-hole pressures with bottom-hole gauges. However, for many problems, a sufficiently pressure and temperature, formation temperature, and well depth is critically analyzed.



.Figure 1 Gas Production Schematic

Aziz (1986) tried to estimate the absolute open flow potential of a gas well. He did this in conjunction with the Texas railroad commission to calculate the bottom-hole pressure using the average T and Z method. As the name implies, it assumed a constant compressibility factor determined from an assumed average temperature and pressure for the entire flow column. Although these assumptions are fairly accurate in shallow wells, this procedure results in more error as depth, temperature, and pressure increase.

Peffer et al (1988) presented a method for calculating bottom-hole pressures from well head measurements in flowing gas wells this time with liquids present in the well stream.Several modifications have been made to the method to take into account condensate and water production. The modifications treated the gas/liquid system as a pseudo-homogenous mixture and making reference to the cullender and smith method of calculating the static and flowing bottom-hole pressures which takes into account variations in temperature and compressibility factor with change in depth. He assumed that the flow is steady state and kinetic energy were neglected and thereby expressing the mechanical energy balance equation thus;

$$\int_{Ptf}^{Pwf} \frac{\left(\frac{p}{Tz}\right)dp}{\frac{665\,Fmq^{2}}{d^{5}\,(\frac{L}{D})}+\left(\frac{p}{Tz}\right)2} = \frac{\Upsilon D}{53.34} \quad (1)$$

Where P_{wf} is the bottom hole flowing pressure, $P_{tf}$is the tubing head flowing pressure, T is the temperature, Z is the gas compressibility factor, F_m is the moody friction factor, q is the flow rate, d is the pope internal diameter, Υ is the gas gravity, L is the length of the flow string and D is the true vertical depth. Although, this is a more accurate method than the average *T* and *z* method proposed by Aziz et al(1986) and the Railroad Commission and others. Again,this theoretical improvement makes little difference at less than 4,000 or 5,000 ft [1220 or 1525 m] in depth, but it does make asignificant difference in deep, high-pressure, high-temperature gas wells drilled so often today.

Another modification was made on the Cullender and smith method by Oden et al (1988) which accounted for just water production and employing a friction factor correlation to take into account smooth-turbulent and rough-turbulent flow at any absolute roughness. This was partially related to the modification by Peffer et al (1986) except for the fact that he didn't account for liquid condensates in the gas well. The modification primarily included a gas-water ratio term, and a friction factor term as given by the explicit Jain-Swamee correlation.

$$\int_{Ptf}^{Pwf} \frac{\frac{199.3}{R_w}(\frac{P}{Tz})^2+\frac{P}{Tz}}{\frac{H}{L}(\frac{P}{Tz})^2+\frac{2666.5fq^2}{d^5}}\,dp (2)$$

This equation included the gas water ratio (H/L) into the cullender and smith for the calculation of flowing bottom-hole pressures with water production.

Messer et al (1974) presented a method for calculating bottom-hole pressures for deep, hot and sour gas wells. He primarily focused on the sukker and cornel method for computing the bottom hole flowing pressure with strong emphasis laid on the constant B and reduced temperature. He concluded that the Sukkar-Comell method for calculating bottom-hole pressures was an accurate, fast method that avoids trial-and-error calculations. He claimed it was by far the fastest hand calculation method for flowing conditions. The method was also extended to include non-vertical wells, and reduced bottom-hole pressures as high as 30.

Also, Fowler (2003) .proposed an analysis and presented a general approach to calculating both static and flowing bottom-hole pressures for pure natural gas. They derived a pressure integral for perfectly vertical pipe by assuming negligible kinetic energy change, steady-state isothermal flow, and no work done by the gas in flow. He then evaluated the integral generally in terms of pseudo reduced pressures. A somewhat neglected method of calculating bottom-hole pressures, that of Sukkar and Cornell, does not involve trial and error and is very fast for hand calculation; but it does not allow for the severe conditions of modern gas wells.

Economides (2002) proposed a calculation method for predicting bottom-hole pressures based on easily obtainable well head parameters which was not only desirable, but necessary in a high temperature well also with the presence of highly corrosive condensable gases. Several correlations were made which included four calculation procedures for the estimation of the bottom-hole pressures. Two of which were for static pressures and the other two for flowing wells.

There are several methods in calculating the production performance of a gas well. This includes the use of analytical expressions to establish inflow performance relationships under pseudo-steady flow conditions.

Several models have been used to estimate the production performance of a well which includes estimation of the static and flowing bottom hole pressure data. These estimation requires extensive analysis because these techniques used in predicting the production performance of deviated gas wells via the bottom home pressure are some-times error prone in different wellbores.

This study aims at comparing flowing bottom-hole pressures using different gas well deliverability models and analyzing these models and choosing the most effective based on available well data.

II. METHOLOGY

2.1 Overall Research Methodology

This work aims at comparing with the three primary methods for calculating bottom hole pressures two niger delta gas wells in the same reservoir when the gas well was shut in and when it was flowing. The results will then be analyzed to determine which model should be employed in different well depths and operating conditions.

2.2 Problem Solving Step

- Gathering of well data
- Calculation of Static and flowing bottom hole pressures
- Comparison with the actual measured bottom hole pressures from pressure gauges
- Analysis of Results

2.2.1 GATHERING OF WELL DATA

Two dry gas wells in the niger delta were evaluated for the static and bottom hole pressures.

Table 1 Niger Delta Gas well Data

PARAMETERS	WELL 1	WELL 2
Flowing B.H.P (psia)	3265.5	3242
Flowing B.H.T (°F)	168	168
Static B.H.P (psia)	3293	3265
Static B.H.T (°F)	170	167
Wellhead pressure (psia)	2500	2500
Specific gravity	0.65	0.62
Well depth (ft)	10282	10180
Diameter (in)	$2\frac{3}{8}$	$2\frac{3}{8}$
Reservoir Temperature (°F)	170°F	170°F
Wellhead Temperature (°F)	82	79
Angularity	50°	47°
Flow rate (MMscfd)	7.1	7.1

2.2.2 CALCULATION OF STATIC AND FLOWING BOTTOM HOLE PRESSURE

Governing Equation

The energy balance equation was thus rearranged into

$$144v\,dp + \frac{u\,du}{2\alpha g_c} + \frac{g\,dZ}{g_c} + \frac{fu^2}{2g_cD}dL + w_s = 0 \quad (3)$$

Upon integeration of the reduced energy balance equation we have;

$$144\int_1^2 vdp + \frac{g}{g_c}\int_1^2 dZ + \frac{1}{2g_cD}\int_1^2 fu^2dL = 0 \ (4)$$

The density of the gas at any point in a pipeline can be given as

$$\rho_g = \frac{28.97\gamma_g p}{zRT} \qquad (5)$$

Also the velocity of the gas flow U_g at a cross section of a vertical pipe may be defined as

$$U_g = \frac{\dot{m}}{\Pi D^2 \rho_g} = \frac{4mzRT}{\Pi D^2 28.97\gamma_g p} \quad (6)$$

Combining equations 2.9, 2.10 and 2.11 and employing petroleum units, the vertical flow equation becomes

$$\int_1^2 \frac{\frac{zdp}{p}}{1+\frac{667fq^2T^2z^2}{D^5p^2}} = \int_1^2 \frac{28.97\gamma_g\, dL}{10.732(144)T} = \int_1^2 \frac{0.01875\gamma_g\, dL}{T} \quad (7)$$

And assuming a constant temperature in the interval of interest, we have

$$\int_1^2 \frac{\frac{zdp}{p}}{1+\frac{667fq^2\bar{T}^2z^2}{D^5p^2}} = \frac{0.01875\gamma_g\, dL}{\bar{T}} (8)$$

The three models to be analyzed for estimation of static and flowing bottom-hole pressures for the niger delta gas wells are;

- *AVERAGE Z AND T METHOD*
- *SUKKAR AND CORNELL METHOD*
- *CULLENDER AND SMITH METHOD*

This models will be compared manually and with the use of MICROSOFT EXCEL with the computation of its relative error when compared to the actual bottom hole pressures measured with the bottom hole pressure gauges.

Each model had different empirical and analytical expression for estimation of the bottom hole pressures in different well scenarios (static or flowing).

2.2.2.1 STATIC BOTTOM HOLE PRESSURE

The static or shut in bottom hole pressure involves the pressure exerted by the weight of the static fluid column. This is usually exerted when the well is not producing and at this point, the flow rate of the gas well is equal to zero thereby reducing (7) to

$$\int_1^2 \frac{zdp}{p} = \int_1^2 \frac{0.01875\gamma_g\, dL}{T} (9)$$

This is a special case of a vertical flow equation.

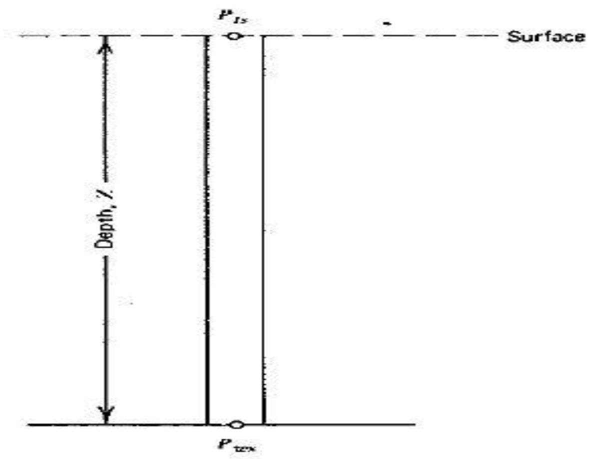


Figure 2A static gas well

where P_{ts} is the pressure at the surface and P_{ws} is the pressure at the depth feet below the surface.

The temperature profile in the static gas well is also shown thus;

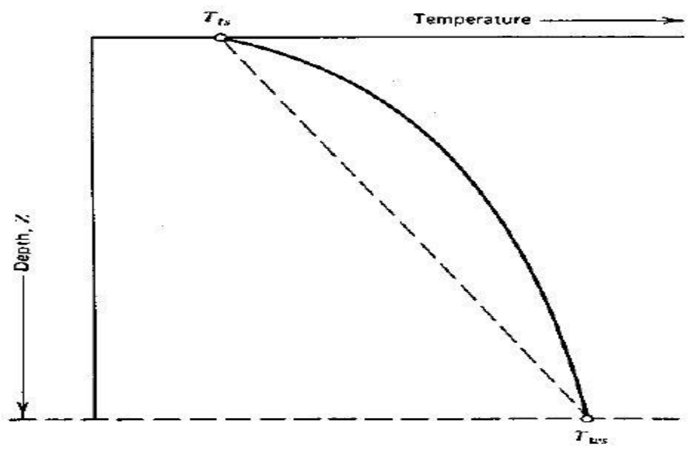


Figure 3 Temperature profile in a static well

The temperature profile is not straight but because of the circulation in the static gas well, it tends to be higher than indicated by a straight line connecting the surface and reservoir temperatures.

2.2.2.1.1 AVERAGE T AND Z METHOD

This average temperature and compressibility factor is based on the assumption that an average temperature and an average gas compressibility factor can be used to simplify the calculation of static bottom-hole pressure. Due to its simplicity, this method is typically used to obtain approximate first-order estimations of bottom-hole pressures.

Equation 3.1 is rewritten as

$$\int_{P_{ts}}^{P_{ws}} \frac{zdp}{p} = \int_0^z \frac{0.01875\,\gamma_g\, dL}{T} \qquad (10)$$

If T and Z are taken outside of the integrals as average value of temperature and compressibility factor, (10) is reduced to

$$In\frac{P_{ws}}{P_{ts}} = \frac{0.01875\,\gamma_g\, Z}{\dot{z}\dot{T}} \qquad (11)$$

where P_{ws} is the static bottom hole pressure (psia)

P_{ts} is the static wellhead pressure (psia)

γ_g is the specific gravity of the gas

Z is the well depth from the surface (ft)

$\dot{T}$ is the average temperature of the bottom and well head temperatures assuming linear temperature profile

$\dot{Z}$ is the z value at average temperature and pressure.

2.2.2.1.2 SUKKAR AND CORNELL

This method was employed by Sukkar and cornell and Fowler(2003) who integrated the left hand side of the basic energy equation at various average temperatures. (7) and(8) can be integrated and pseudo reduced parameters employed thereby;

$$\int_{P_{pr\,1}}^{P_{pr\,2}} \frac{\frac{zd\,P_{pr}}{P_{pr}}}{1+\frac{Bz^2}{P_r^2}} = \frac{0.01875\,\gamma_g\, Z}{\dot{T}} \qquad (12)$$

But for a static case, B=0 thereby reducing 3.4 to

$$\int_{P_{pr\,1}}^{P_{pr\,2}} \frac{zd\,P_{pr}}{P_{pr}} = \frac{0.01875\,\gamma_g\, Z}{\dot{T}} \qquad (13)$$

$P_{pr\,2}$ = pseudo reduced well head pressure

$P_{pr\,1}$ = pseudo reduced bottom-hole pressure

z= gas deviation factor of gas (well effluent) at $\dot{T}$ and varying pressures within the flowstring

$$B = \frac{667\,f\,q^2\dot{T}^2}{D^5 P_{pc}^2}$$

P_{pc} = pseudo critical pressure of natural gas (psia)

The value of B is usually read in the sukkar and cornellintegeral table

2.2.2.1.3 CULLENDER AND SMITH METHOD

The Cullender-Smith method involves a numerical integration technique for calculating BHSP and takes into account both variations in temperature and compressibility factor with depth. This was also proposed by Ikoku (1984) and peffer et al (1988) .He assumed that equation (8) can be rearranged into

$$\int_{P_t}^{P_w} \frac{\frac{P}{Tz}dp}{\frac{2.6665\,(f/4)q^2}{D^5}+\frac{1}{1000}\left(\frac{P}{Tz}\right)^2} = \frac{1000\,\gamma_g\, Z}{53.34} \qquad (14)$$

P_w = bottom hole flowing pressure (psia)

P_t = wellhead (tubing) pressure (psia)

γ_g = specific gravity of natural gas

L = length of pipe (ft)

q = gas flow rate (MMscfd)

T = absolute temperature °R

z = gas deviation factor

D = internal diameter (in)

Z = well depth (ft)

We may define I as $\frac{\frac{P}{Tz}dp}{\frac{2.6665\,(f/4)q^2}{D^5}+\frac{1}{1000}\left(\frac{P}{Tz}\right)^2}$ (15)

which is reduced to;

$I = 1000\left(\frac{Tz}{P}\right)$ (16)

for a static case where q=0

This equation is solved with a two-step numerical integration. This procedure, described by Ikoku(1984) involves iterative calculations based on dividing the wellbore into two parts using the trapezoidal and Simpson's rule . Selecting depths at 0, Z/2 and Z, (16) can be expressed as;

$$\int_{P_{ts}}^{P_{ws}} 1000\left(\frac{Tz}{P}\right)dp = \frac{(P_{ms}-P_{ts})(I_{ms}+I_{ts})}{2} + \frac{(P_{ws}-P_{ms})(I_{ws}+I_{ms})}{2} \qquad (17)$$

Which can be reduced into

$$(P_{ms}-P_{ts})(I_{ms}+I_{ts}) + (P_{ws}-P_{ms})(I_{ws}+I_{ms}) = 37.5\gamma_g\, Z \qquad (18)$$

(18)may then me separated into two equations, one for each half of the string

$(P_{ms} - P_{ts})(I_{ms} + I_{ts}) = 37.5\gamma_g \frac{Z}{2}$(19)

$(P_{ws} - P_{ms})(I_{ws} + I_{ms}) = 37.5\gamma_g \frac{Z}{2}$ (20)

(19) is for the upper half of the flow string while (20) is for the lower half of the flow string.

This is then evaluated to show that the static bottom hole pressure at the well depth is given as

$$P_{ws} = P_{ts} + \frac{112.5\gamma_g Z}{I_{ts} + 4I_{ms} + I_{ws}} \quad (21)$$

Where I_{ts} is evaluated at H=0, I_{ms} is evaluated at Z/2 and I_{ws} evaluated at Z.

2.2.2.2 FLOWING BOTTOM HOLE PRESSURE

Whenever the gas well is producing, the flowing bottom-hole pressure is calculated as a function of the well head pressure, weight of the column of gas, the frictional losses in the tubing, and the changes in kinetic energy in the system. The kinetic energy is very small compared to the other energies (usually 0.1%) and thereby omitted in the energy equations.

(8) Can be rewritten as

$$\frac{53.34Tz}{\gamma_g P} dp + dZ + 0.00268 \frac{f}{D^5} \left(\frac{Tz}{P}\right)^2 q^2 dL = 0 \quad (22)$$

(22)is the governing equation for flowing bottom hole pressures using any model.

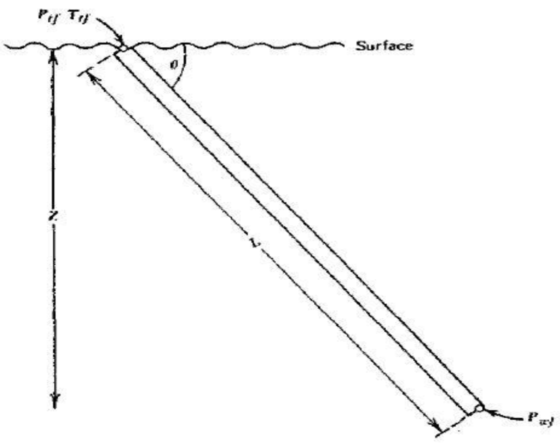


Figure 4 Flowing gas well

Considering the slanted gas well of length L and angle θ from the horizontal

Sin $\theta = \frac{Z}{L}$ thereby making $dL = \frac{L}{Z} dZ$ (23)

2.2.2.2.1 *AVERAGE T AND Z METHOD*

This method is usually employed to estimate an approximate value of flowing bottom hole pressure because of its simplicity.

Putting equation (23) in (22), it becomes

$$\frac{53.34Tz}{\gamma_g P} dp + \left(1 + 0.00268 \frac{f}{D^5} \left(\frac{Tz}{P}\right)^2 q^2 \frac{L}{Z}\right) dZ = 0 \quad (24)$$

Using average values and integrating

$$\frac{53.34\dot{T}\dot{z}}{\gamma_g} \int_{P_{tf}}^{P_{wf}} \frac{dp}{\left[p + 0.00268\, f/D^5 (\dot{T}\dot{z}q)^2 \frac{L}{Z}\right]} = -\int_0^z dZ \quad (25)$$

From calculus;

$$\int \frac{Pdp}{C^2 + P^2} = \frac{1}{2} In(C^2 + P^2)$$

(25) then becomes

$$In\left(\frac{C^2 + P_{wf}^2}{C^2 + P_{tf}^2}\right) = \frac{2\gamma_g Z}{53.34\dot{T}\dot{z}} \quad (26)$$

Substituting for C in 3.18

$$P_{wf}^2 = P_{tf}^2 e^s + \frac{25\gamma_g \dot{T}\dot{z}\dot{f}L(e^5 - 1)q^2}{sD^5} \quad (27a)$$

Where $P_{wf =}$ flowing bottom hole pressure (psia)

$P_{tf =}$flowing well head pressure (psia)

$s = 2\gamma_g Z/53.34\dot{T}\dot{z}$ (27b)

Ṫ =arithmetic average of bottom hole and wellhead temperature, °R

ż =gas deviation factor at the arithmetic average Temperature and arithmetic average pressure ḟ = Moody friction factor at arithmetic average of temperature and pressure.

L= length of flow string (ft)

Z = vertical distance of reservoir from the surface(ft)

q = gas flow rate (MMscfd) at 14.7psia and 60°F

D= Flow string internal diameter (in)

This method assumed constant temperature and deviation factor over the entire length of the conduit.

2.2.2.2.2 SUKKAR AND CORNELL METHOD

The sukkar and cornel method applies to both vertical and inclined wells. This method for calculating flowing bottom hole pressure assumed a steady state flow, single-phase flow, constant friction over the length of the conduit and constant temperature at some average value.

The integral was evaluated in terms of pseudo reduced pressures. Over three decades ago, a modification was made to the sukkar and cornell method which accounted for angularity in the well and thus the integral can be written as

$$\frac{\gamma_g\, L cos\theta}{53.34\,\dot{T}} = \int_{P_{(tf)r}}^{P_{(wf)r}} \frac{z/P_{pr}}{1+B\left(\frac{z}{P_{pr}}\right)^2} dP_{pr} \qquad (28)$$

This model proposes the use of log mean average temperature over the normal arithmetic average. Here Ṫ is given as

$$\dot{T} = \frac{T_{res} - T_{surf}}{In\frac{T_{res}}{T_{surf}}} \qquad (29)$$

$$\text{Where } B = \frac{667 f q^2 \dot{T}^2}{D^5 P_{pc}^2 Cos\theta} \qquad (30)$$

$$\text{And } Cos\theta = \frac{Z}{L} \qquad (31)$$

The integral on the right of equation (28) can be evaluated on any arbitrary lower limit usually $P_{(tf)r}$ = 0.2

This then makes the sukkar and cornell model reduced to

$$\int_{0.2}^{P_{(wf)r}} I(P_r) d\,P_r = \int_{0.2}^{P_{(wf)r}} I(P_r) d\,P_r + \frac{\gamma_g\, Z}{53.34\,\dot{T}} \qquad (32)$$

This accounts for small amount of contaminants in the natural gas (H_2S, CO_2).

2.2.2.2.3 CULLENDER AND SMITH METHOD

This method doesn’t make assumptions of temperature of compressibility factor and therefore doesn’t undergo normal mathematical integration.

The general equation for the flow for deviated gas wells may be expressed as

$$\frac{1000\gamma_g Z}{53.34} = \int_{P_{tf}}^{P_{wf}} \frac{\frac{P}{Tz} dp}{F^2 + \frac{1}{1000}\frac{Z}{L}\left(\frac{P}{Tz}\right)^2} \qquad (33)$$

$$\text{Where } F^2 = \frac{2.6665\,(f/4) q^2}{D^5} \qquad (34)$$

This integral in equation (33) can then be solved by numerical means with a two step calculation on the upper and lower part of the string thus;

$$\frac{1000\gamma_g Z}{53.34} = \int_{P_{tf}}^{P_{wf}} I\, dp = \frac{(P_{mf} - P_{tf})(I_{mf} + I_{tf})}{2} + \frac{(P_{wf} - P_{tf})(I_{wf} + I_{tf})}{2} \qquad (35)$$

$37.5\gamma_g Z = (P_{mf} - P_{tf})(I_{mf} + I_{tf}) + (P_{wf} -$ *PtfIwf+Itf (36)*

Upper part of the string becomes

$$37.5\gamma_g \frac{Z}{2} = (P_{mf} - P_{tf})(I_{mf} + I_{tf}) (37a)$$

Lower part of the string becomes

$$37.5\gamma_g \frac{Z}{2} = (P_{wf} - P_{tf})(I_{wf} + I_{tf}) (37b)$$

Applying Simpson’s, (37a) and (37b) is fused to

$$37.5\gamma_g Z = \frac{P_{wf} - P_{tf}}{3}(I_{tf} + 4I_{mf} + I_{wf}) \quad (38)$$

The friction factor is also computed for a fully turbulent flow as

$$F = \frac{0.10796q}{D^{2.612}} \qquad (39)$$

This is usually applied when the diameter of the conduit is less than 4.277 inches.

2.2.3 COMPARISON AND ANALYSIS

After all flowing and static gas well pressures have been calculated for using the different models, the relative errors (RMS) will be computed for all models as compared to each other and compared to the actual bottom hole pressures measured with bottom hole gauges.

The Root mean square error is given mathematically as

$$\left[\frac{\%Error^2}{n}\right]^{0.5} \qquad (40)$$

Where the % Error is given as

$$\frac{P_{measured} - P_{calculated}}{P_{measured}} \qquad (41)$$

III. RESULTS AND DISCUSSION

This study makes an extensive computation and analysis on the different models for determining gas well deliverability via its bottom hole pressures. This analysis is based on the comparisons and relative closeness of the estimated bottom hole pressures to the actual pressures measured using bottom hole pressure gauges. This estimation was computed on two different wells sunk to the same reservoir with different well conditions of temperature, pressure and well depth.

3.1*RESULT DATA*

Table 2 Calculated Static Bottom Hole Pressures

MEASU-RED BOTTOM HOLE PRESSURES (psia)	**AVER-AGE T AND Z MODEL** ($psia$)	**SUKKER AND CORNELL MODEL** ($psia$)	**CULLE-NDER AND SMITH MODEL** ($psia$)
3293	3257.46	3261.06	3265.42
3265	3200.16	3199.39	3206.511

Table 3 Calculated Flowing Bottom Hole Pressures

MEASURED WELL PRESSURES ($psia$)	**AVERAGE T AND Z MODEL** ($psia$)	**SUKKER AND CORNELL MODEL** ($psia$)	**CULLE-NDER AND SMITH MODEL** ($psia$)
3265.5 psia	3208.55$psia$	3214.09	30
3242 psia	3144.2	3200.67	2959.56

3.2 RELATIVE ERRORS OF THE MODELS

The Root mean square error was computed for each model for static and flowing conditions using (40).

The results was given, thus

Table4 Error Computation of Static Well Models

WELL	***MEASURED BOTTOM-HOLE PRESSURE***	***AVERAGE Z AND T METHOD***		***SUKKAR AND CORNELL METHOD***		***CULLENDER AND SMITH METHOD***	
		BHP_{cal}	%Error	BHP_{cal}	%Error	BHP_{cal}	%Error
1	3293	3257.46	+1.08	3261.06	+0.97	3265.42	+0.84
2	3265	3200.16	+1.99	3199.39	+2	3206.511	+1.79

Table 5 Error Computation Of Flowing Well Models

WELL	***MEASURED BOTTOM-HOLE PRESSURE***	***AVERAGE Z AND T METHOD***		***SUKKAR AND CORNELL METHOD***		***CULLENDER AND SMITH METHOD***	
		BHP_{cal}	%Error	BHP_{cal}	%Error	BHP_{cal}	%Error
1	3265.5	3208.55	+1.74	3214.09	+1.57		+6.9
2	3242	3144.2	+3.0	3200.67	+1.3	2959.56	+8.71

3.3 COMPARATIVE ANALYSIS OF CORRELATION RESULTS

The gas well used for this analysis was a dry gas well with insignificant composition of contaminants and impurities and minimal condensate production. For the estimation of the static bottom hole pressures, the well was assumed to a vertical well (L=Z) but for the estimation of the flowing bottom hole pressures, a highly deviated well with angularity from the horizontal was modeled for which varied in the results given by the three different models.

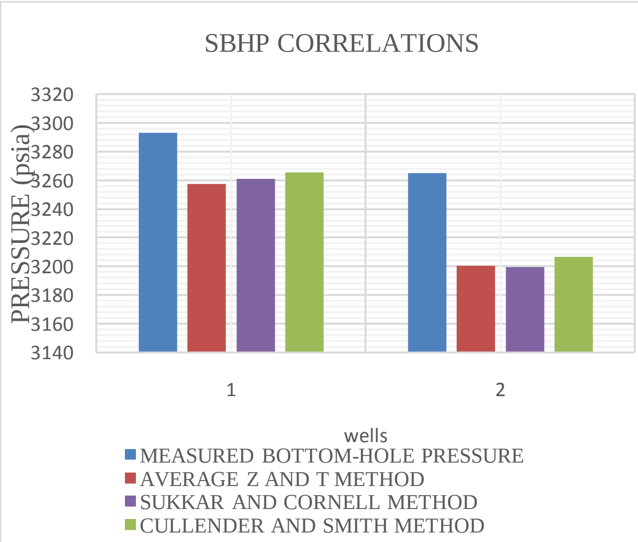


Figure 5 Static bottom hole correlation models

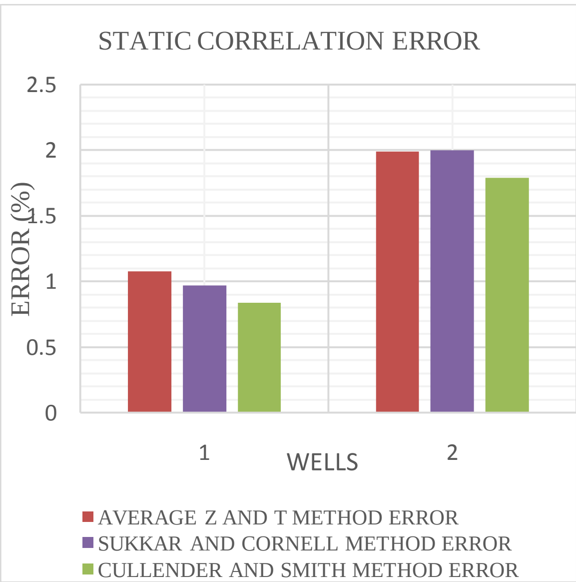


Figure 6 Static bottom hole correlation model errors

From the plots shown above, the average z and T model and the sukkar and cornell model gave very close values to the actual static bottom hole pressure and very infinitesimal errors but the cullender and smith method showed a relative closeness to the measured vertical static bottom hole pressure from bottom hole gauges. It also had the lowest error computed (0.85% and 1.79%) as compared to the other two models and is thus best selected for computing bottom hole pressures of vertical wells having a pressure range of 3000-4000psia and a depth of 8000-12000ft.

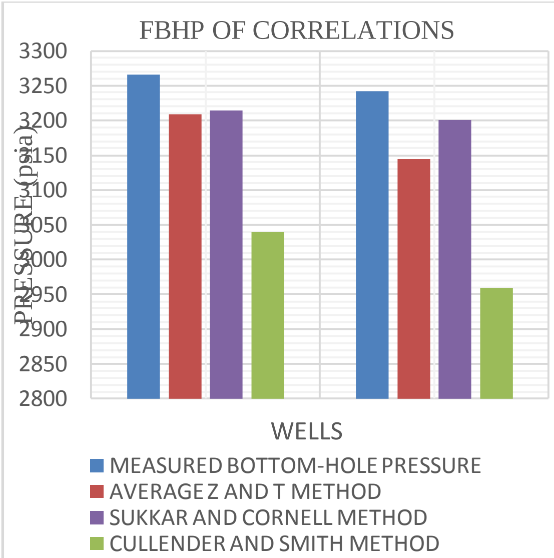


Figure 7 Flowing bottom hole correlation models

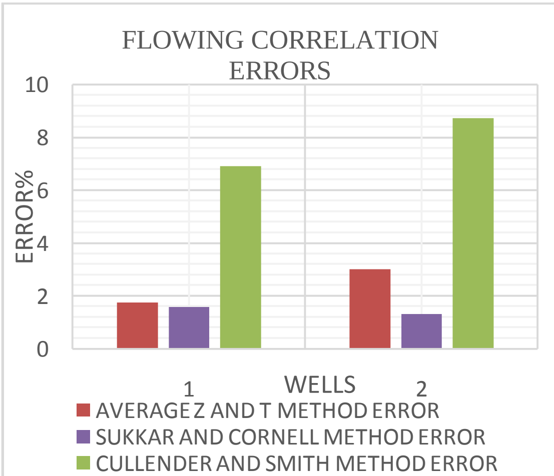


Figure 8Flowing bottom hole correlation model errors.

Highly deviated gas wells have an impact on the calculation of flowing bottom-hole pressures. The plots above were made on a deviated well with each model estimating a near value to the measured flowing bottom-hole pressure. The cullender and smith method which proved to the best initially accounted for a lot of errors due to deviation of the well from the horizontal. The Sukker and cornell outperformed the other models for deviated flow conditions.

3.4 ACCURACIES OF THE CALCULATED BOTTOM HOLE PRESSURES

The bottom-hole pressures have proven to be dependent on well head pressure, temperature and well depth as well as the distance of the wellhead from the reservoir for deviated flow conditions.

Generally, all models provided satisfactory results as compared to the measured bottom-hole pressures but it was observed that the Cullender and smith method was more accurate in calculation of the static bottom-hole pressures with a minute error computed for the vertical well but deviated much more for inclined wells in the calculation of the flowing bottom-hole pressures.

The sukker and cornel method proved to be preferred for the range of depths and pressures above 7500 ft and 1000psia respectively with the sukkar and cornell table. For true vertical depths up to 7500ft, a constant compressibility factor and temperature can be assumed over the entire depth for all models which is the primary assumption of the sukker and cornel. This is the main reason why the sukkar and cornell method gave the least error among the three models combined.

The Average Z and T method was an equally good method in determining the bottom-hole pressures due to its simplicity but cannot be relied on very large depths above 10000ft with the variation of temperatures and pressures with depth. It was observed that the average z and T method gave a more accurate result with reduction in depth.

IV. CONCLUSION AND RECOMMENDATION

The analysis of the results showed that the errors estimation of BHPs increased with decreasing true vertical depth for the cullender and smith but decreased with decreasing true vertical depth of the well with the average T and Z method. This shows that except modifications are carried out on this models, the average T and z method will be preferred over the cullender and smith for inclined wells while cullender and smith is better for vertical wells. The sukkar and cornel method is chosen preferably among the three models for inclined wells and vertical wells less than 10000psia due to its accuracy, consistency and simplicity.

Compositional analyses were not available on these wells, so the compressibility factors calculated with these methods were not adjusted for the presence of H_2S, CO_2, and N_2, which added a degree of uncertainty to all the calculated BHP's. This could not be avoided; however, it did affect the pressures calculated by the models methods equally.

4.1 RECOMMENDATIONS

There are many modifications and promising prospects that can be researched and proposed on in the near future for computing a more accurate BHP.

- The cullender and smith model is a very accurate method for calculating bottom-hole pressures but modifications should be made on this model to ensure consistency and accuracy for deviated gas well conditions.

- The gas deviation factor is a very important and sensitive parameter for determining the bottom-hole pressure. It shouldn't be read in charts but from actual laboratory measurements on combined fluid samples.

- Modifications could also be carried out on all BHP models for deviated wells to also account for liquid and condensate production and liquid entrainment in the gas streams

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