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Acoustic Determination of Producing Bottomhole Pressure

James N. McCoy, SPE, Echometer Co.
Augusto L. Podio, SPE, U. of Texas
Ken L. Huddleston, SPE, Echometer Co.

Summary. This paper discusses the acoustic determination of producing bottomhole pressure (BHP). Two different techniques are presented for wells that have liquid above the formation and gas flowing upward through the gaseous liquid column. One technique involves the acoustic measurement of the liquid level and the casing-pressure buildup rate when the casinghead valve is closed. When these data are used along with an empirically derived correlation given here, the gradient of the gaseous liquid column in the annulus can be obtained. This technique offers a reasonably accurate procedure for determining the producing BHP of a well by acoustic means. The second method involves two acoustic measurements. A backpressure valve is used in the casing head to depress and to stabilize the liquid level at two positions while the well is produced at a constant rate. The gradient of the gaseous liquid column is then calculated and extrapolated to the formation depth.

This paper discusses results from the field testing of numerous wells where the actual gradients of gaseous liquid columns were measured in a variety of casing/tubing sizes, oil gravities, gas flow rates, and pressures.

Introduction

The producing-rate efficiency of a well can be determined with the curve of inflow performance relationship,[1] which requires knowledge of the producing and static BHP's. Techniques for determination of static BHP's by acoustic means have been presented in Refs. 2 through 5. These techniques have proved to be sufficiently accurate for most conditions.

The producing BHP is the sum of the surface casing pressure plus the pressure from the column of fluids in the annulus.

The fluid distribution in the annulus is a function of the producing conditions of the particular well. Three situations are generally found in the field: (1) the liquid level is at or near the formation and casinghead gas may or may not produced; (2) the liquid level is above the formation and casinghead gas is not produced; and (3) the liquid level is above the formation and casinghead gas is produced.

Fig. 1 illustrates these three cases. For Cases A and B, the pressure distribution is well defined from a measurement of the pressure at the surface, a knowledge of the properties of the fluids, and the position of the liquid level. Case C, on the other hand, involves the uncertainty of the gaseous liquid column gradient as a result of the annular gas flow.

Liquid Level at Formation (Case A). The casinghead pressure constitutes the major portion of the producing BHP in normal-depth wells because the pressure from the gas column is relatively small. Even when gas is being vented, the frictional pressure losses are minimal. BHP calculation is undertaken from a measurement of the casinghead pressure, the knowledge of the gas composition, and the temperature distribution as described in Ref. 2. Or the BHP calculation can be performed by a computer program given in Ref. 6. This program also includes Cases B and C.

The liquid level will always be at the tubing perforations when a well is being produced with the casing valves closed and free gas is flowing from the formation.

Liquid Level Above Formation Without Free Gas Flow From Reservoir (Case B). At stabilized producing conditions, the liquid above the tubing perforations is 100% oil. This producing BHP is calculated from measurement of the surface casinghead pressure, measurement of the depth to the liquid level by an acoustic survey, and a knowledge of the oil and gas properties. Details of the calculation are given in Ref. 2.

Liquid Level Above Formation With Casinghead Gas Flow (Case C). This condition results in a gaseous annular liquid column. At stabilized producing conditions, the oil in the casing annulus becomes saturated with the gas that is continuously flowing to the surface. Consequently, if gas is being vented at the surface at a constant rate, free gas is being produced from the formation simultaneously with the oil. Generally, most oil is produced through the pump while most free gas is produced up the casing annulus.

BHP calculation is undertaken from a measurement of casinghead pressure, knowledge of oil and gas properties, and an estimate of the oil fraction in the annular liquid. The fraction estimate is required to obtain the gradient of the gas/liquid mixture. This problem has received considerable attention by numerous authors.[7-11] These techniques involve the determination of the gas flow rate up the annulus and, in turn, the calculation of the amount of liquid present in the gaseous liquid column by use of such well conditions as casing/tubing sizes, liquid properties, and pressure. All these methods are based on a combination of theoretical and empirical models and yield different results for a given set of conditions as shown by Kabir and Hasan.[10]

Because of the disagreement of these techniques, a comprehensive field study was performed to determine directly the gradient of gaseous liquid columns.

The wells tested during this study included casing sizes from 4.5 to 7 in. [11.4 to 18 cm] and oil gravities between 32 and 43°API [0.86 and 0.81 g/cm^3]. Long gaseous liquid columns of more than 5,000 ft [1525 m] were studied in wells up to 9,000 ft [2745 m] deep. Annular gas flow rates ranged from 13 to 120 Mcf/D [368 to 3400 m^3/d] and oil fractions ranging from 20 to 77% were measured. The wells were located in regions of normal temperature gradients in the range of 0.9 to 1.2°F/100 ft [16.4 to 21.9 mK/m].

When a gaseous liquid column exists in the annulus of a well producing at stabilized conditions, the pressure at any depth in the gaseous column is independent of the surface pressure. This is illustrated in Fig. 2, which is a schematic of a well producing at three different values of casinghead pressure. The producing BHP remains unaffected by the changes in surface pressure and liquid level as long as the production rates through the tubing and the casing annulus remain constant.

The annular pressure for three cases is plotted as a function of depth in Fig. 3. The gradient of the gaseous column (gas/oil mixture) can be obtained from the change in liquid level and in pressure at the gas/liquid interface.

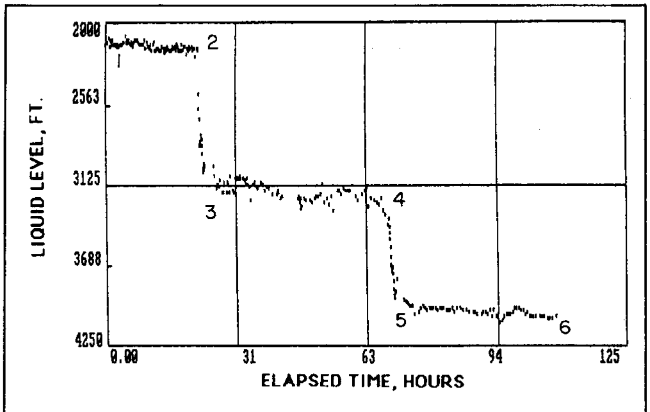

Fig. 5—Field recording of annular fluid-level depth corresponding to Fig. 4.

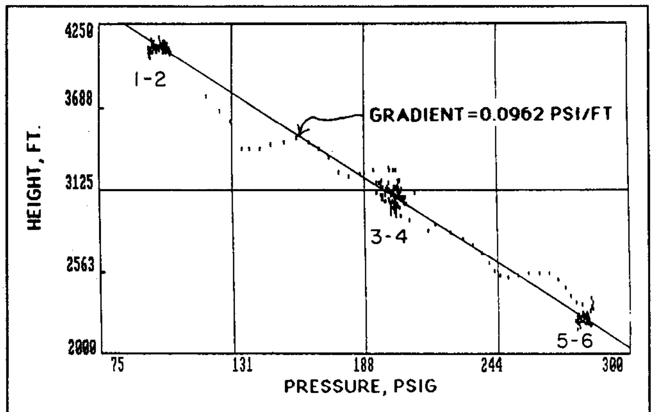

Fig. 6—Gaseous liquid column height as a function of pressure at the gas/liquid interface.

g_{mt} = measured total gradient, and
g_o = gradient of gas-free oil.

This term was then correlated directly with the corresponding annular gas flow rate and annular area as shown in Fig. 7. Note that implied in the correlation is the effect of temperature and gas compressibility factor, because it is derived with field data from regions with normal temperature gradients and wells producing casinghead gas with specific gravity corresponding to oils in the 32- to 43°API [0.86- to 0.81-g/cm^3] gravity range.

Direct measurement of annular gas flow in the field is a tedious process that can be avoided by estimating the gas flow from a short casing-pressure-buildup test. The test is conducted by closing the casing valve while the well continues to pump. The rate at which casing pressure increases is measured. During the early phase of this study, it was observed that annular gas flow rates calculated by short casing-pressure-buildup tests generally were less than the rates measured with a critical flow prover. This error was a result of considering only the volume of gas above the liquid level and neglecting the gas bubbles present in the gaseous liquid column. The procedure was corrected as follows: once the gradient present was determined, an effective oil fraction was calculated and, in turn, the volume of gas present in the column was estimated and added to the volume of gas above the fluid level, yielding an adjusted depth to the liquid level:

$$D_a = D_L + (1 - f_o)L, \quad \text{(3)}$$

which is then used to calculate the annular gas flow rate.

$$Q = \frac{0.00068 \times \Delta p A D_a}{\Delta t}, \quad \text{(4)}$$

where
Δp = change in pressure,
Δt = elapsed time, and
A = cross-sectional area of annulus.

To facilitate use of the effective-oil-fraction correlation, it has been plotted with its axis representing the terms corresponding to the casing-pressure-buildup rate times the adjusted depth to the liquid level:

$$\left(\frac{\Delta p}{\Delta t}\right) D_a .$$

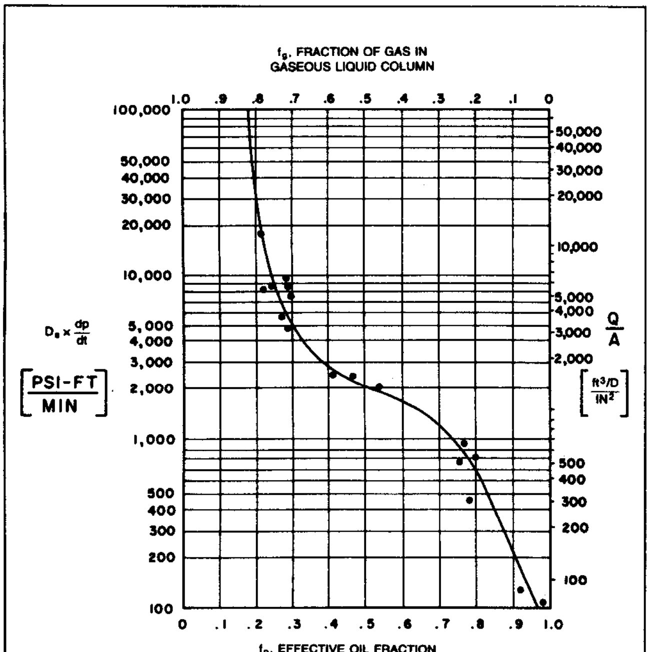

Fig. 7—Echometer gaseous liquid column gradient correction curve.

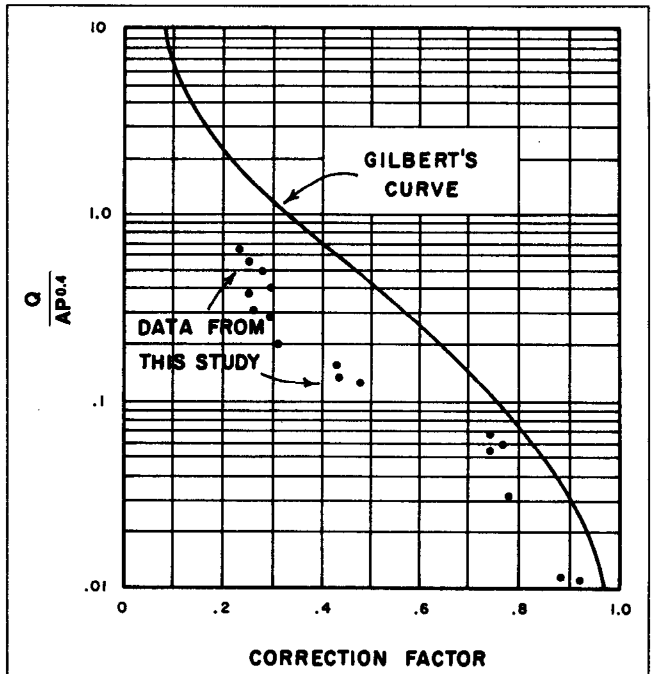

Fig. 8—Comparison of Gilbert's gradient-correction-factor curve with data points from this experimental study.

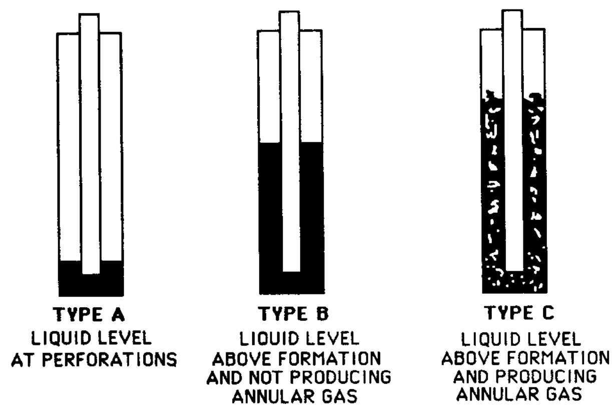

Fig. 1—Fluid distribution in the annulus of a pumping well.

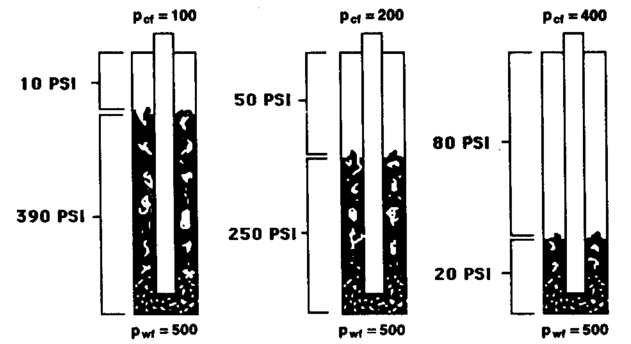

Fig. 2—Pressure relations in a pumping well with a gaseous fluid column.

The gaseous oil column gradient is equal to the difference in pressures at the two fluid-level depths divided by the distance between them:

$$g_{glc}=\frac{[(p_{cf2}+p_{gc2})-(p_{cf1}+p_{gc1})]}{(D_{L2}-D_{L1})}, \quad \quad (1)$$

where D_{L2} and D_{L1} are the depths to the liquid level at pressures p_{cf2} and p_{cf1}, respectively, and p_{gc1} and p_{gc2} are the pressures from the hydrostatic gas column.

Eq. 1 suggests the procedure for field determination of the gaseous column gradient: the liquid level can be depressed by increasing the casing pressure. Then, after waiting until stabilized flow conditions are re-established, the new liquid level is measured and the gaseous column gradient is calculated with Eq. 1.

It will generally take considerable time (more than 24 hours) for stabilized conditions to be established when an increase in the casinghead pressure occurs. During this transient period, the pressure buildup at the surface (caused by the accumulation of gas flowing into the gas column from the gaseous liquid column) will result in a pressure increase in the annulus and at the formation. This increase causes liquid to be depressed from the casing annulus into the pump, thus restricting fluid flow and possibly causing liquid backflow into the formation. During this time, the liquid level in the annulus will drop to a lower level. After gas begins to vent at the increased stabilized surface pressure, the surface gas flow rate will stabilize at the original value and the liquid level will stabilize as the producing BHP returns to its original value. In some instances, this process may take 1 or more days.

Testing Procedure

With the use of a backpressure valve, the casing pressure was increased to a specific value and then stabilized by allowing annular gas to vent at its original rate. When casing pressure ceases to increase, liquid from the annulus is no longer forced into the pump and the producing BHP returns to its original value. The well is in a stabilized condition and a true gradient can be calculated.

During earlier tests, BHP sensors, dynamometers, and portable well testers were used to determine when stabilization occurred. As experience was gained, the results showed that a stabilized flowing condition was accurately indicated by a stabilized liquid level, obviating the need for this auxiliary equipment.

Figs. 4 and 5 show the most recent field data, obtained by a microprocessor-controlled test system[12] that allows data to be taken as frequently as once a minute, thus yielding an accurate and detailed description of the behavior of the fluids in the well. The casing pressure is plotted as a function of time in Fig. 4. Measurements were made at three stabilized values of casinghead pressure: 80 psi [551 kPa] (Points 1 and 2), 180 psi [1.2 MPa] (Points 3 and 4), and 250 psi [1.7 MPa] (Points 5 and 6). The corresponding fluid-level behavior is presented in Fig. 5, which shows that for this particular well, fluid-level stabilization occurs in a relatively short time, 5 to 10 hours.

The measured gradient includes both the hydrostatic (mixture density) and the dynamic (friction and kinetic energy) components. The linear behavior with depth shows that the total gradient remains practically constant, even though the pressure varies by a factor of 3 or 4 as shown in Fig. 6. This behavior was observed in all the field tests covered by this study. The measured total gradient was expressed in terms of the gas-free oil gradient by introducing a term defined as the effective oil fraction:

$$f_o=g_{mt}/g_o, \quad \quad (2)$$

where

f_o = effective oil fraction,

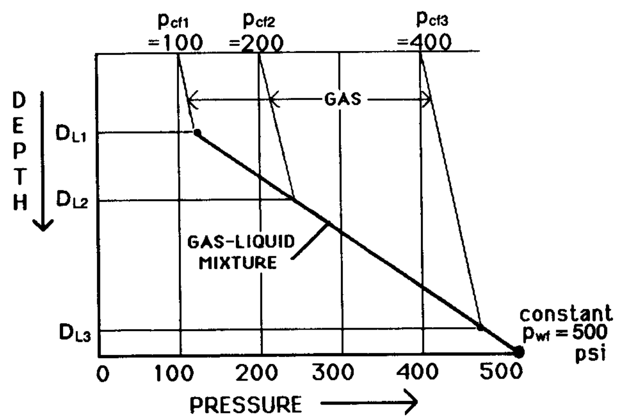

Fig. 3—Pressure/depth traverse in the annulus for the cases illustrated in Fig. 2.

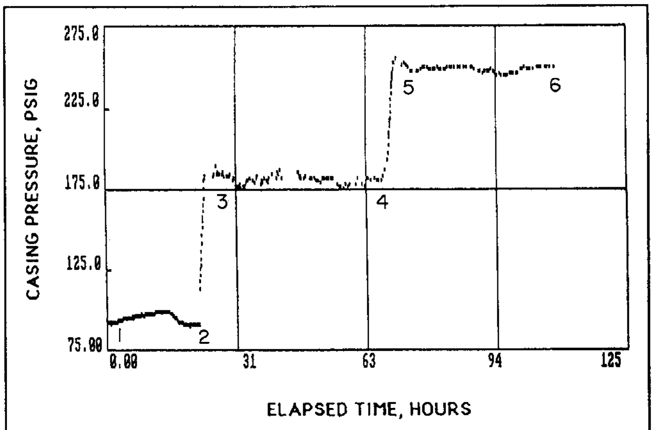

Fig. 4—Field recording of casinghead pressure during fluid-level stabilization procedure.

TABLE 1—SAMPLE CALCULATION

Depth to formation, ft	7,000
Depth to gaseous liquid column, ft	3,000
Oil gravity, °API	42
Oil gradient, psi/ft	0.353
Casing-pressure buildup, psi	10
Buildup time, minutes	30
Casing pressure, psig	100
Gas column pressure, psi	10
$\Delta p/\Delta t$, psi/min	0.333
D_a, ft	$3{,}000+(1-1)4{,}000=3{,}000$
$(\Delta p/\Delta t)D_a$, psi-ft/min (assume oil fraction = 1)	1,000
Oil fraction (from Fig. 7)	0.72
D_a, ft	$3000+(1-0.72)4{,}000=4{,}120$

Iterate until oil fraction converges as shown below

D_a	$(\Delta p/\Delta t)D_a$	f_o
4,120	1,371	0.63
4,480	1,492	0.62
4,520	1,505	0.62

Gaseous column pressure, psig	$=0.62(0.353)4{,}000=875$
p_{wf}, psi	$100+10+875=985$

To date, the most commonly used method to estimate the gradient in a gaseous liquid column is Gilbert's curve. For this reason, the data points were plotted on Gilbert's curve and are shown in Fig. 8. Gilbert's curve predicts gradients greater than those measured in the field tests, sometimes by a factor of two.

Determining Acoustic Producing BHP's

The simplest technique to calculate a producing BHP is to determine acoustically the distance to the top of the gaseous liquid column and measure the casing-pressure-buildup rate. Then, use Fig. 7 to determine the effective oil fraction.

The producing BHP will then be

$$p_{wf}=p_{cf}+p_{gc}+g_o f_o L. \quad (5)$$

The gas column pressure, p_{gc}, can be calculated by various well-known methods that include the effect of gas gravity, z factor, and temperature.[2,4] Because the adjusted depth, D_a, is a function of the oil fraction and vice versa, the effective oil fraction will have to be obtained with a short iterative process starting with an oil fraction of one as shown in the sample calculation in Table 1. Note that care must be taken in measuring the casing-pressure-buildup rate. At a buildup rate of 1 psi [6.9 kPa] in 10 minutes, which might be overlooked, an effective oil fraction of 0.80 could exist. A minimum of 10 psi [69 kPa] and/or 10 minutes should be used in each casing-pressure buildup for the best results.

The second method, known as Walker's method,[13] involves the determination of the liquid level at two different casing pressures. The use of a backpressure valve is required to stabilize the well at the higher casing pressure. Be sure that the casing pressure and the gaseous liquid level have stabilized at both conditions.

The gaseous liquid column gradient is calculated with Eq. 1. Using this gaseous liquid gradient, the producing BHP may be calculated as

$$p_{wf}=p_{cf2}+p_{gc2}+g_{glc}(D_f-D_{L2}). \quad (6)$$

The accuracy of this method increases as the depth to the second liquid level approaches the formation.

Note that care must be taken to leave a small amount of liquid above the pump to be sure that additional gas is not being forced into the pump.

Application to Pressure-Buildup Work

To obtain the most accurate pressure data at the earliest times, the top of the gaseous liquid level should be stabilized near, but above, the pump before the well is shut in. Otherwise, oscillations of the gaseous liquid column prevent obtaining accurate early-time data.

Using the backpressure-valve technique presented here will increase the accuracy of the calculated BHP and afterflow. Also, if the gaseous liquid column is stabilized a short distance above the pump, then the influence of possible errors in the effective-oil-gradient correlation is diminished.

Conclusions

Calculation of producing BHP can be performed in 90% of pumping wells without consideration for gaseous liquid columns. Most wells are in the first two categories described, either having no liquid above the formation or having liquid above the formation without annular gas flow.

In wells where gaseous liquid columns are present, the producing BHP can be obtained by use of the correlation presented here. For additional accuracy, the difficult, expensive, and lengthy Walker's method may be used to obtain the producing BHP. Accuracy from Walker's method depends on depressing and properly stabilizing the liquid level near the pump.

This study, based on actual gradients measured in the annulus, offers increased accuracy over previously reported correlations based on theory and surface models.

Nomenclature

A = cross-sectional area of annulus, in.^{2} [cm^2]
D_a = adjusted depth to liquid level, ft [m]
D_f = depth to formation, ft [m]
D_L = depth to top of liquid, ft [m]
f_o = effective oil fraction
g_{glc} = gradient of gaseous liquid column, psi/ft [kPa/m]
g_o = gradient of gas-free oil column, psi/ft [kPa/m]
L = length of gaseous liquid column, ft [m]
p_{cf} = casing pressure at producing conditions, psig [kPa]
p_{gc} = pressure exerted by gas column, psi [kPa]
p_{glc} = pressure exerted by gaseous liquid column, psi [kPa]
p_{wf} = producing BHP, psig [kPa]
Q = annular gas flow rate, Mcf/D [m^3/d]
Δt = time, minutes
1,2 = denotes separate stabilized conditions

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SI Metric Conversion Factors

°API	141.5/(131.5 + °API)		=	g/cm^3
ft	× 3.048*	E−01	=	m
psi	× 6.894 757	E+00	=	kPa

*Conversion factor is exact.

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