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The New, Generalized Material Balance as an Equation of a Straight Line: Part 1—Applications to Undersaturated, Volumetric Reservoirs

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ABSTRACT

This work presents a general, straight-line method to estimate the original oil and gas in-place in a reservoir without restrictions on fluid composition. All past efforts are applicable to only restricted ranges of reservoir fluids. Our work supersedes these and is the first to be applicable to the full range of reservoir fluids—including volatile-oils and gas-condensates. Our work is based on the new generalized material-balance equation recently introduced by Walsh.[1] The superiority of the new method is illustrated by showing the error incurred by preexisting calculation methods. Guidelines are offered to help identify when preexisting calculation methods must be abandoned and when the new methods featured herein must be employed. The results of our work are summarized in a set of companion papers. Part 1 discusses applications to initially-undersaturated, volumetric reservoirs and Part 2 discusses applications to initially-saturated and non-volumetric reservoirs.*

INTRODUCTION

This work completes the search for a general, straight-line method to estimate the original oil and gas in-place. No restrictions are placed on initial fluid compositions. This breakthrough is made possible by the new, generalized material-balance equation (GMBE) recently introduced by Walsh.[1] Unlike the conventional material-balance equation (CMBE),[2-7] the GMBE uniquely accounts for volatilized-oil. Volatilized-oil is the stock-tank oil content of the free reservoir gas-phase. By including both dissolved-gas and volatilized-oil, the GMBE is uniquely applicable to the full range of reservoir fluids. Because our straight-line method is based on the GMBE, it too is applicable to the full range of reservoir fluids. All preexisting straight-line methods are applicable to only restricted ranges of reservoir fluids. This restriction is now no longer necessary.

This work leads to a new and improved method of analyzing reservoir performance. Together with Walsh's work,[1] it leads to a complete and comprehensive understanding of the influence of phase behavior on reservoir performance. It also leads to a new, improved, and innovative way to teach reservoir engineering.

The results of our work are summarized in a set of companion papers. Part 1 presents the mathematical development and discusses applications to initially-undersaturated, volumetric reservoirs. Initially-undersaturated reservoirs are those whose initial but not necessarily final pressure is greater than the saturation (dew or bubble point) pressure. Volumetric reservoirs are those whose hydrocarbon pore volume does not change. Part 2 discusses applications to initially-saturated and non-volumetric reservoirs. Initially-saturated reservoirs include, but are not restricted to, gas-cap reservoirs; non-volumetric reservoirs include, but are not restricted to, water-influx reservoirs. Part 1 is restricted to simple expansion-drive reservoirs and Part 2 discusses combination-drive reservoirs.

BACKGROUND

Interest in developing straight-line methods to estimate petroleum reserves began with the development of p/z-plots to estimate gas reserves in dry-gas reservoirs. This well-known method of estimating gas reserves was in common practice by the 1940's.[8] Since this time, there has been considerable interest in developing straight-line methods for other types of petroleum reservoirs.

In 1963, Havlena and Odeh[9] developed a popular straight-line method for oil reservoirs. Their work was based on expressing the conventional material-balance equation (CMBE) as an equation of a straight line. The CMBE was based on the following assumptions: (1) there are, at most, two hydrocarbon components: stock-tank oil and surface-gas; (2) the surface-gas component can partition into both the reservoir oil- and gas-phases; and (3) the stock-tank oil component can partition into only the reservoir oil-phase. The first assumption defined the highly popular two-hydrocarbon-component formulation. The second assumption allowed for dissolved- or solution-gas. And the last assumption ignored the possibility of volatilized-oil. This assumption also restricted application of the CMBE to black-oil and dry-gas reservoirs and precluded its application to volatile-oil and gas-condensate systems. Because Havlena and Odeh's work was based on the CMBE, it was subject to the same

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* References and illustrations at end of paper.

limitations. Despite these limitations, the CMBE has enjoyed widespread use among reservoir engineers.[2-7,9-20]

The search for a more general straight-line method continued. In the late 1980's, a new class of straight-line methods emerged to treat gas-condensate reservoirs.[21-23] A common element of each of these works was that they used the two-phase z-factor. These methods were highly reminiscent of the p/z-plots used in dry-gas reserve evaluation.

Though each of these cited works represented important advancements, none were applicable to the full range of reservoir fluids. This shortcoming caused fragmentation by suggesting that different types of fluids demanded different type of treatments. Also, the applicability of each method was ill-defined and it was not always clear where the applicability of one method ended and another began.

Our work eliminates this potential confusion and completes the search for a general, straight-line method to estimate the original oil and gas in-place. No restrictions are placed on the initial fluid compositions. Our work is based on the GMBE recently introduced by Walsh.[1] Walsh's material-balance equation was unique in that it was the first to include volatilized-oil. Equally important, it retained the simplicity of the two-hydrocarbon-component formulation popularized in earlier developments. By including both dissolved-gas and volatilized-oil, Walsh was able to overcome the long-standing limitations of the CMBE and introduce a material-balance equation which was applicable to the full range of reservoir fluids—including volatile-oils and gas-condensates. Walsh's approach to account for volatilized-oil was similar to that used by Cook et al.[24] to broaden the black-oil, finite-difference reservoir simulator from its original black-oil formulation[25-32] to the popular modified black-oil formulation.[33,34] Walsh's work included showing how his new material-balance equation could be used to estimate oil reserves in volatile-oil and gas-condensate reservoirs; however, his work did not include any graphical solution methods.

We recognize the significance of Walsh's effort and we extend it by presenting simple graphical methods to estimate the original oil and gas in-place. Our work is reminiscent of the work of Havlena and Odeh[9] and we honor their work by retaining as much of their nomenclature as possible.

MATHEMATICAL DEVELOPMENT

A mass balance over a constant-volume system which initially contains free oil- and gas-phases demands:

$$F = N_{foi}\,E_o + G_{fgi}\,E_g + \Delta W \qquad (1)$$

where N_{foi} is the stb of stock-tank oil originally in the free oil-phase; G_{fgi} is the scf of surface-gas originally in the free gas-phase; F is the RB of total hydrocarbon fluid withdrawal; E_o is the net expansion of the original free oil-phase expressed as RB/stb; E_g is the net expansion of the original free gas-phase expressed as RB/scf; and ΔW is the net increase in the reservoir water volume expressed in RB. Note that N_{foi} and G_{fgi} are constants and F, E_o, E_g, and ΔW are functions of pressure.

If we account for volatilized-oil in the reservoir gas-phase, then F, E_o, and E_g are defined by:

$$F = N_p\left[\frac{B_o\left(1 - R_v R_{ps}\right) + \left(R_{ps} - R_s\right) B_g}{\left(1 - R_v R_s\right)}\right] \qquad (2a)$$

$$E_o = \frac{\left(B_o - B_{oi}\right) + B_g\left(R_{si} - R_s\right) + R_v\left(B_{oi} R_s - B_o R_{si}\right)}{\left(1 - R_v R_s\right)} \qquad (2b)$$

$$E_g = \frac{\left(B_g - B_{gi}\right) + B_o\left(R_{vi} - R_v\right) + R_s\left(B_{gi} R_v - B_g R_{vi}\right)}{\left(1 - R_v R_s\right)} \qquad (2c)$$

where N_p is the stb of cumulative produced oil and R_{ps} is the ratio of the scf of cumulative produced sales gas (G_{ps}) and the stb of cumulative produced oil (N_p). The cumulative produced sales gas is equal to the cumulative produced wellhead gas if and only if there is no gas re-injection. If B_o, B_g, R_s, and R_v have units of RB/stb, RB/scf, scf/stb, and stb/scf, respectively, then Eqns. (1) and (2) are applicable as written and require no conversion factors. The remaining variables (with units) are defined in the nomenclature. Collectively, Eqns. (1) and (2) represent the GMBE and these equations are derived in Appendix A. Eqns. (1) and (2) have been presented before except in a slightly different algebraic form and for the case of only initially-undersaturated reservoirs.[1] Our development is more general and considers initially-saturated or initially-undersaturated reservoirs.

If we ignore volatilized-oil, then F, E_o, and E_g are defined by:

$$F = N_p\left[B_o + \left(R_{ps} - R_s\right) B_g\right] \qquad (3a)$$

$$E_o = B_o - B_{oi} + B_g\left(R_{si} - R_s\right) \qquad (3b)$$

$$E_g = B_g - B_{gi} \qquad (3c)$$

Collectively, Eqns. (1) and (3) represent the CMBE and their application has been thoroughly discussed by Havlena and Odeh.[9] The application of these equations is limited to black-oil and dry-gas systems and they are not applicable to volatile-oil and gas-condensate systems. The definitions in Eqn. (3) are identical to those originally proposed by Havlena and Odeh except they defined F to be the total fluid (hydrocarbon plus water) withdrawal and we define F to be only the hydrocarbon fluid withdrawal. We choose this difference to stress the distinction between hydrocarbon and water withdrawal and to permit us to group the water withdrawal and water influx terms into a single term, ΔW.

As will be shown, if Eqn. (3) is applied to reservoir fluids containing volatilized-oil, it will yield erroneous estimates of F, E_o, and E_g. These errors, in turn, will yield errors in estimating the OOIP and OGIP. If Eqn. (3) yields an error, then it will usually, but not exclusively, overpredict F and E_o and underpredict E_g.

Unique to the GMBE is the use of the volatile oil-gas ratio, R_v. This variable effectively describes the amount of volatilized-oil in the reservoir gas-phase and is typically expressed in units of stb/scf or stb/mmscf. This variable has been introduced and used by others.[24,33,34] Cook et al.[24] referred to R_v as the "liquid content of the gas;" Coats[34] referred to it as the "oil vapor in gas." This variable is distinctly different from but analogous to the dissolved gas-oil ratio, R_s. The volatile oil-gas ratio is a function of the reservoir fluid composition. It also is a strong function of the separator configuration which seeks to maximize liquid dropout. For heavy- and black-oils, the volatile oil-gas ratio at the saturation pressure typically ranges from 0-10 stb/mmscf; for volatile-oils, it ranges from 10-200 stb/mmscf; for near-critical fluids, it reaches maximum values and ranges from 150-400 stb/mmscf; for gas-condensates, it ranges from 50-250; for wet gases, it ranges from 20-100 stb/mmscf; and for dry gases, it approaches zero.

It is important to recognize that the constants N_{foi} and G_{fgi} in Eqn. (1) are not generally equal to the OOIP (N) and OGIP (G), respectively. Most generally, these quantities are related to one another by:

$$N = N_{foi} + G_{fgi}R_{vi} \tag{4}$$

$$G = G_{fgi} + N_{foi}R_{si} \tag{5}$$

where the products $G_{fgi}R_{vi}$ and $N_{foi}R_{si}$ represent the stb of oil in the original free gas-phase and the scf of gas in the original free oil-phase, respectively. These equations follow from mass balances and the fact that stock-tank oil and surface-gas each most generally initially exist in both the reservoir oil- and gas-phases. In certain cases, N_{foi} and G_{fgi} are equal to the OOIP and OGIP, respectively. For example, N_{foi} is equal to the OOIP if the reservoir fluid is an initially-undersaturated oil (G_{fgi}=0). Likewise, G_{fgi} is equal to OGIP if the reservoir fluid is an initially-undersaturated gas reservoir (N_{foi}=0). In Havlena and Odeh's work,[9] for example, N_{foi} was always equal to the OOIP (N) because they ignored volatilized-oil, i.e., they assumed R_v was negligible.

Undersaturated Fluids

Eqns. (2) and (3) apply if and only if the reservoir pressure is less than or equal to the saturation pressure. If the pressure is greater than the saturation pressure, only a single hydrocarbon phase exists and these equations can be greatly simplified. The resulting simplifications are given by:

$$F = N_p B_o \tag{6a}$$

$$F = G_{ps} B_g \tag{6b}$$

$$E_o = B_o - B_{oi} \tag{7}$$

$$E_g = B_g - B_{gi} \tag{8}$$

These equations apply regardless of whether one includes or ignores volatilized-oil. Notice that Eqn. (6) gives two alternative methods to compute F. Eqns. (6a) and (6b) are equivalent and selection is a matter of convenience and depends on whether the single-phase fluid is treated as an oil or gas. If the attending single-phase fluid is treated as an oil and its fluid properties are given in terms of B_o's, then application of Eqn. (6a) is the logical choice. On the other hand, if the single-phase fluid properties are given in terms of B_g's, then application of Eqn. (6b) is the natural choice. Whether one elects to treat the single-phase fluid as either an oil or gas is subjective and, as will be shown, is ultimately immaterial.

For the special case of a single-phase fluid, B_o is related to B_g by

$$B_o = \frac{B_g}{R_v} \tag{9}$$

and R_s is related to R_v by

$$R_s = \frac{1}{R_v} \tag{10}$$

These equations follow from the observation that the distinction between either an oil- or gas-phase is superfluous if only a single hydrocarbon phase exists. Furthermore, if the reservoir pressure is equal to or greater than the saturation pressure, the cumulative sales GOR, R_{ps}, is equal to the solution gas-oil ratio R_s:

$$R_{ps} = \frac{G_{ps}}{N_p} = R_s \tag{11}$$

By combining Eqns. (9)-(11), it can be shown that Eqns. (6a) and (6b) are equivalent.

The relationships given collectively by Eqns. (1) and (2) and Eqns. (6)-(8) are quite general and are applicable to a wide range of reservoir conditions. This paper (Part 1) is restricted to an application of the GMBE to initially-undersaturated, volumetric reservoirs. Accordingly, Part 1 precludes a discussion of gas-cap and water-influx reservoirs. These and other combination-drive reservoirs are discussed in a companion paper (Part 2).[35]

Initially-Undersaturated, Volumetric Oil Reservoirs

If we apply Eqn. (1) to an initially-undersaturated, volumetric oil reservoir, then N_{foi}=N, G_{fgi}=0 and ΔW=0 and we obtain:

$$F = N E_o \tag{12}$$

where F and E_o are given by Eqns. (6a) and (7) if the pressure is greater than the saturation pressure and are given by Eqn. (2) if the pressure is less than or equal to the saturation pressure. Eqn. (12) reveals that a plot of F vs. E_o yields a straight line which passes through the origin and whose slope is equal to N. The OGIP is computed by knowing $G=R_{si}N$.

Initially-Undersaturated, Volumetric Gas Reservoirs

Alternatively, if we apply Eqn. (1) to an initially-undersaturated, volumetric gas reservoir, then G_{fgi}=G, N_{foi}=0 and ΔW=0 and we obtain:

$$F = G E_g \tag{13}$$

where F and E_g are given by Eqns. (6b) and (8) if the pressure is greater than the saturation pressure and are given by Eqn. (2) if the pressure is less than or equal to the saturation pressure. Eqn. (13) reveals that a plot of F vs. E_g yields a straight line which passes through the origin and whose slope is equal to G. The OOIP is computed by knowing $N=R_{vi}G$.

It is largely a matter of preference whether one plots F vs E_o or F vs. E_g to determine N and G. As a matter of practice, we routinely plot F vs E_o for all reservoir fluids including gas-condensates but excluding dry-gases. For the special case of dry-gases, one must plot F vs. E_g because N is zero and E_o is undefined.

RESERVOIR FLUIDS

Our approach to study the GMBE is to: (1) select example reservoir fluids which span the range of interest, (2) develop an equation-of-state (EOS) fluid property description which accurately models the phase behavior of each fluid, (3) carry out numerical PVT experiments to determine the necessary fluid properties such as B_o, B_g, R_s, and R_v for each fluid, (4) carry out numerical simulations to predict the reservoir performance of each fluid, and (5) apply the GMBE via the graphical solution techniques to estimate the OOIP and OGIP and compare these estimates with the actual OOIP and OGIP. All EOS computations were carried out using the Zudkevitch-Joffe[36] modification of the Redlich-Kwong[37] EOS; all reservoir performance predictions used a two-hydrocarbon-component, compositional, tank model.[38]

Four reservoir fluids were selected for study: a black-oil, a volatile-oil, a rich gas-condensate, and a very lean gas-condensate. Table 1 summarizes their reservoir and fluid properties. These fluids were purposely selected to span a wide compositional range. For example, their saturation pressures range from 1,688-7,255 psia, their initial producing GOR's range from 838-22,527 scf/stb, and their dissolved methane contents range from 29-71 mole percent. The black-oil closely mimics a West Texas oil from the Canyon Reef formation at a depth of about 6,700 ft;[39,40] the volatile-oil simulates a North-central Louisiana oil from the Smackover limestone at a depth of about 10,000 ft;[41] and the rich gas-condensate closely simulates a Western Overthrust Belt gas-condensate from the Triassic-Jurassic Nugget formation at a depth of about 12,800 ft.[42,43]

Figure 1 shows the results of a constant composition expansion (CCE) for each fluid at its respective reservoir temperature. The bubble point pressures of the black- and volatile-oils are 1,688 and 4,677 psia, respectively; the dew point pressures of the rich and lean gas-condensates are 5,430 and 7,255, respectively. The oils show the characteristic trend of a decreasing volume-percent liquid with decreasing pressure and the condensates exhibit retrograde condensation. The rich gas-condensate is considerably "richer" than the lean gas-condensate as evidenced by its considerably greater volume-percent liquid.

Tables 2a-5a summarize the fluid properties for each fluid as a function of pressure. The tabulated fluid properties include B_o, B_g, R_s, R_v, phase viscosities (μ_o and μ_g), phase z-factors (z_V and z_L), and two-phase z-factors (z_2). B_o, B_g, R_s, R_v, and the phase viscosities were computed from differential vaporizations. The z-factors were computed from CCE's. The two-phase z-factor is defined later, Eqn. (17). The values of B_o, B_g, R_s, and R_v, at pressures greater than the saturation pressure are related to one another by Eqns. (9) and (10).

TESTING MATERIAL-BALANCE EQUATIONS

In general, we recommend testing the accuracy of any particular material-balance formulation to predict the attending phase behavior before applying it to analyze reservoir performance. The purpose of testing includes: (1) to determine whether the effects of volatilized-oil are important, (2) to identify whether the GMBE is necessary or the CMBE is sufficient, and (3) to identify potentially erroneous PVT data. One method of testing is to compare the results of routine laboratory tests (e.g., differential vaporization or CCE) with predictions by demanding conservation of mass. The testing procedure may require first deriving new material-balance relationships to simulate the selected laboratory test. We illustrate the testing procedure for the case where laboratory CCE data is available.

CCE tests measure the volume-fraction liquid as a function of pressure. Unlike a petroleum reservoir which represents a constant-volume, open system; a CCE test represents a variable-volume, closed system. A mass balance on such a system yields:

$$V_o = \frac{1}{1 + \dfrac{B_g(R_{si} - R_s)}{B_o(1 - R_{si} R_v)}} \qquad (14)$$

where V_o is the volume-fraction liquid. Eqn. (14) includes the effects of volatilized-oil as evidenced by the presence of the R_v term. If we ignore volatilized-oil (R_v=0), then Eqn. (14) becomes:

$$V_o = \frac{1}{1 + \dfrac{B_g(R_{si} - R_s)}{B_o}} \qquad (15)$$

Eqns. (14) and (15) are derived in Appendix B. Because Eqn. (14) includes and Eqn. (15) ignores volatilized-oil, we also refer to them as generalized and conventional material balances, respectively. To use Eqns. (14) and (15) to predict the volume-fraction liquid, the fluid properties B_o, B_g, R_s, and R_v must be known as a function of pressure.

If Eqn. (14) matches the CCE data appreciably better than Eqn. (15), then volatilized-oil cannot be neglected and the GMBE is needed to model reservoir performance. This case will likely occur if the reservoir fluid is a volatile-oil or gas-condensate. If, on the other hand, Eqns. (14) and (15) match the CCE data equally well, then volatilized-oil can be neglected and the CMBE is sufficient to analyze the reservoir performance. This case will likely occur if the reservoir fluid is a black-oil.

Figs. 2 and 3 show example calculations illustrating Eqns. (14) and (15). Figs. 2 and 3 consider the black-oil and rich gas-condensate fluids, respectively. The dots in Figs. 2 and 3 represent the experimentally-simulated CCE data. The solid and dashed curves show the results of Eqns. (14) and (15), respectively. For the case of the black-oil, Fig. 2 shows that Eqns. (14) and (15) yield virtually identical results and they each predict the CCE data very well. This agreement confirms that the effect of volatilized-oil is negligible for this fluid and suggests that the CMBE should be sufficient to analyze reservoir performance.

In contrast, Fig. 3 shows that Eqns. (14) and (15) yield appreciably different results. Eqn. (14) matches the CCE retrograde condensation very well, but Eqn. (15) fails to predict any retrograde condensation. This disparity between Eqns. (14) and (15) means that the effect of volatilized-oil is indeed significant and the GMBE is likely needed to analyze reservoir performance.

A close inspection of Fig. 3 reveals that the conventional material-balance calculations [Eqn. (15)] actually yield a jump discontinuity in the liquid volume fraction at the saturation pressure (5,430 psia). This non-physical result illustrates the broad problem of applying the conventional material balance (i.e., ignoring volatilized-oil) to model a gas-condensate. Mathematically, this discontinuity is caused by the jump discontinuity in the solution gas-oil ratio, R_s, at the saturation pressure. See Table 4a. Gas-condensates yield a jump discontinuity in R_s because they physically yield a discontinuity in the oil-phase composition at the saturation pressure. This occurs because, at pressures greater than the saturation pressure, there is no oil-phase; whereas, at pressures less than the saturation pressure, there is an oil-phase whose composition is markedly different from the co-existing gas-phase or the initial fluid composition. Jump discontinuities in R_s are physically realistic. The jump discontinuity in R_s leads to the non-physical result in Fig. 3 only because the effects of volatilized-oil are ignored. See the difference between Eqns. (14) and (15). This observation will help explain the discontinuities we shall observe later in this work. The results in Fig. 3 demonstrate the greater applicability of the generalized material balance and the limitations of the conventional material balance.

APPLICATIONS

Tables 2b-5b summarize the reservoir performance of each fluid. The results are given in terms of the %OOIP and %OGIP recovered, the instantaneous and cumulative producing GOR's, and the gas saturation as a function of reservoir pressure. Figure 4 shows the gas-oil relative permeability curves used in the simulations. The performance simulations were carried out to final pressures in the range 200-600 psia. We report the simulation results to such low pressure levels for the sake of completeness and not to imply that such low final pressure levels are necessarily economically attainable. The final oil recoveries expressed as %OOIP for the black-oil, volatile-oil, rich gas-condensate, and lean gas-condensate are 27.9, 22.6, 23.7, and 35.2%, respectively; the final oil recoveries expressed as stb of oil recovered per RB of hydrocarbon pore space are 0.190, 0.083, 0.054, and 0.028, respectively; the final gas recoveries expressed as a %OGIP are 77.8, 82.2, 80.5, and 80.9%, respectively. The reservoir oils exhibit a monotonically increasing gas saturation during pressure depletion, whereas the gas-condensates exhibit retrograde condensation. These results are qualitatively consistent with the CCE results.

Figures 5a-5d plot F vs. E_o for each fluid. For convenience, we have normalized the total fluid withdrawal F by the OOIP (N). In practice, this type of normalization is not possible because the OOIP is normally not known beforehand. We carry out this normalization for ease of presentation and so that each of our examples can be treated as having an OOIP of 1 stb. The dots and squares in Fig. 5 denote the GMBE and CMBE calculations, respectively. The solid and dashed lines represent the best-fit lines through the GMBE and CMBE data points, respectively. The plots in Fig. 5 include only the first five data points for the black-oil and the first six data points for the other fluids. We show only the early-time production data because reservoir engineers are most interested in determining reserves early rather than late in the reservoir's life. The best-fit lines and their slopes were computed using the least-squares method.

The plots of F vs. E_o show that the GMBE calculations consistently yield a linear plot regardless of the reservoir fluid composition. On the other hand, the CMBE calculations yield a linear plot for only the black-oil and yield non-linear plots for the volatile-oil and gas-condensates. These results illustrate the generality of the GMBE and the limitations of the CMBE. The GMBE and CMBE calculations yield identical results for the black-oil because R_v is sufficiently small and the GMBE and CMBE are equivalent for this case. See Eqns. (2) and (3).

The slope of the lines in Fig. 5 yield the OOIP estimates. Application of the GMBE yields an accurate OOIP estimate for each reservoir fluid. In contrast, application of the CMBE yields an erroneous OOIP estimate for all fluids except the black-oil. Table 6 summarizes the errors. The CMBE yields errors of 0, 21.8, 52.2, and 40.7%, respectively, for the black-oil, volatile-oil, rich gas-condensate, and lean gas-condensate. In each case the CMBE under-predicts the OOIP if an error occurs. These results show that the error incurred by the CMBE is greatest for rich gas-condensates and then dissipates as the fluid approaches either a black-oil or dry-gas. These results imply that the error is directly related to the magnitude of R_v.

For each reservoir fluid, notice that the GMBE and CMBE data points in Fig. 5 are identical at pressures greater than the saturation pressure. This result follows directly from Eqns. (6)-(8). We intentionally selected sufficiently high initial pressures to clearly illustrate this effect. The GMBE and CMBE data points in Fig. 5 are different only if the reservoir pressure is less than or equal to the saturation pressure and only for the volatile-oil and gas-condensate examples. See Figs. 5b-5d. This result follows from the difference between Eqns. (2) and (3).

Though not obvious, the CMBE calculations for the rich and lean gas-condensates actually yield a discontinuity in the value of E_o at the saturation pressure. This discontinuity may not be readily apparent to the reader because we have carried out material-balance calculations at discrete pressure points rather than as a continuous function of pressure. In any case, this discontinuity occurs because gas-condensates yield a discontinuity in the oil-phase composition as one crosses their phase boundary. This effect was discussed earlier. A discontinuity in E_o does not occur for volatile-oils because they do not exhibit an oil-phase composition discontinuity as one crosses their phase boundary. See Fig. 5b. The fact that gas-condensates yield a E_o-discontinuity and volatile-oils do not, partially explains why gas-condensates yield a greater error when applying the CMBE to estimate the OOIP. Incidentally, the discontinuity in E_o for gas-condensates would not be present if the initial pressure was less than or equal to the saturation pressure; however, the CMBE calculations would still yield erroneous OOIP estimates in this case because the resulting slope of a plot of F vs E_o would still be in error.

The conventional material-balance OOIP estimates are included for the sake of comparison and to illustrate their error magnitude if the CMBE is applied outside its range of applicability. Based only on a broad understanding of the CMBE assumptions, it is perhaps clear that one should not apply the CMBE to gas-condensates. Our results certainly support this conclusion. However, it is not clear as to how much fluid-volatility a reservoir oil can exhibit before one can no longer justifiably use the CMBE and one must apply the GMBE. More broadly, the limits of applicability of the CMBE are not clear. Our experience and mathematical development permits us to offer some guidelines. An inspection and comparison of Eqns. (2) and (3) reveals that the two material balances are equivalent if $R_vR_{ps}<<1$ and $R_vR_s<<1$, where R_{ps}, R_s, and R_v must be expressed in appropriate units to yield unitless products. In our experience, we find that this condition is usually met if the volatile oil-gas ratio, R_v, is less than 10 stb/mmscf. Our experience agrees with the observations of Walsh.[1] Thus, if there is interest in applying the CMBE and its applicability is in question, we recommend measuring the fluid's volatile oil-gas ratio at its saturation pressure and comparing it to the critical value offered herein.

DISCUSSION

The purpose of this work is to present a simple graphical method based on the GMBE to determine the OOIP and OGIP. The new method offered herein is applicable to the full range of reservoir fluids of interest, including volatile-oils and gas-condensates. Owing to its generality, this work represents a revolutionary advancement over past efforts. Recently, other investigators[21-23] have proposed alternative graphical techniques to estimate the OOIP and OGIP for volatile-oils and gas-condensates. These alternative methods are all quite reminiscent of the p/z-plots used to determine the OGIP in dry-gas reservoirs and they all have the common element of using the two-phase z-factor. Although these alternative methods are quite acceptable under certain circumstances, they do not possess the robustness of the GMBE and they can lead to errors.

To illustrate the limitations of these alternative approaches, we consider the method proposed by Hagoort.[21] Hagoort proposed a graphical method whereby one plots p/z_2 vs. G_{pe}, where z_2 is the two-phase z-factor and G_{pe} is the total produced gas-equivalent. His method presumes the reservoir pressure is directly measurable and is known at intermittent times. The total produced gas-equivalent is defined as the sum of the produced separator-gas and the produced stock-tank oil expressed as gas-equivalent. The gas-equivalent is usually expressed in units of scf or moles. The produced stock-tank oil is converted to gas-equivalent by assuming each mole of stock-tank oil results in one mole of gas-equivalent. The scf of gas-equivalent per stb of oil, for example, is given by R_{go}

$$R_{go} = \frac{2126\,\rho_o}{M_o} \tag{16}$$

where R_{go} has units of scf/stb and ρ_o is the stock-tank oil density in units of lbs/cf and M_o is the stock-tank oil molecular weight. The constant of 2126 in Eqn. (16) represents the product of 5.61 cf/bbl and 379 scf/lbmole. Table 1 tabulates R_{go} for the fluids studied herein. The two-phase z-factor, z_2, is defined by

$$z_2 = z_V\,V + z_L\,L \tag{17}$$

where z_V and z_L are the gas- and liquid-phase z-factors and V and L are the mole fractions of gas and liquid. The quantities on the right-side of Eqn. (17) are determined from either a laboratory constant composition expansion (CCE), differential vaporization, or constant volume depletion.

Hagoort recommended plotting p/z_2 vs. G_{pe}, drawing a line through the data using the least-squares method, and then extrapolating the line to zero gage pressure to determine the total original gas-equivalent in-place OGEIP (G_e). G_e is related to the OOIP (N) and OGIP (G) by

$$G_e = G + R_{go}\,N = N\left(\frac{1}{R_{vi}} + R_{go}\right) \tag{18}$$

where we have used $R_{vi}G=N$ for simplification if the reservoir fluid is initially-undersaturated.

Figs. 6a-6d show the P/z_2 vs. G_{pe} plots for each of the four example fluids. Tables 2-5 tabulate z_L, z_V, z_2, and G_{pe}/G_e as a function of pressure for each fluid. The z-factors were computed from a CCE. Figs. 6a-6d also include the linear extrapolations through the early-time data points. The extrapolations were determined using the procedure recommended by Hagoort and based on the first five data points for the black-oil and the first six data points for the other fluids. Table 6 summarizes the error incurred by Hagoort's method. Hagoort's method yields errors of 36, 5, 13, and 2%, respectively, for the black-oil, volatile-oil, rich gas-condensate, and lean gas-condensate. In all cases, Hagoort's method over-estimates the OOIP and OGEIP. Hagoort recommended that his method be limited to sufficiently lean gas-condensates and our calculations show good OOIP estimates for this case. The black-oil and volatile-oil calculations are included only for the sake of reference and comparison. They clearly show the limitations of Hagoort's method.

The lack of generality of and the error incurred by Hagoort's method is due to the inability of the laboratory-measured two-phase z-factor to agree with the reservoir (actual) two-phase z-factor. This disparity is due to the failure of the selected laboratory test to accurately simulate the gas saturation history in the reservoir. Vo et al. [22,23] recognized these limitations in their work and they used a slightly different approach to help broaden the method's range of applicability. The two-phase z-factors used in our calculations were computed from the CCE. Hagoort's method shows less error for the lean gas-condensate than the rich gas-condensate because the CCE predicts the gas saturation history better for the lean gas-condensate than the rich gas-condensate. Admittedly, two-phase z-factors computed from a constant volume depletion test might lead to improved results. However, regardless of the laboratory test used to estimate the two-phase z-factor, any test will introduce error of this nature if the reservoir experiences simultaneous two-phase (hydrocarbon) flow. It is important to note that the graphical methods introduced in this paper are not subject to this type of error because they do not depend on a laboratory test to predict the gas saturation. More importantly, though, the graphical methods introduced herein are general and apply without restriction to the type of reservoir fluid.

CONCLUSIONS

A new graphical method to estimate OOIP and OGIP in petroleum reservoirs has been presented. The new method is based on the new GMBE recently developed by Walsh.[1] Example calculations have been presented for a wide range of reservoir fluids of interest. The new graphical methods are shown to accurately estimate the OOIP in each case. In contrast, preexisting graphical calculation methods are shown to yield erroneous OOIP estimates if they are applied to the full range of reservoir fluids. Helpful guidelines have been offered to identify when graphical methods presented heretofore must be abandoned and when the new graphical methods featured herein must be applied.

The new method represents a significant advancement over previous efforts and has the following advantages or features: (1) it is general and applicable to the full range of reservoir fluid—including volatile-oils and gas-condensates, (2) it is simple, (3) it is analogous to Havlena and Odeh's popular method for black-oils and dry-gases, (4) it is not highly sensitive to the laboratory tests used to determine the necessary fluid properties, (5) it is readily adaptable to include the effects of other supplemental production mechanisms such as gas-cap expansion and water influx, (6) it is analogous to the modified black-oil method presently used in finite-difference reservoir simulation, and (7) it yields a more unified approach to understand reservoir performance and to teach reservoir engineering.

This paper (Part 1) discussed applications to initially-undersaturated, volumetric reservoirs. A companion paper[35] (Part 2) discusses applications to initially-saturated and non-volumetric reservoirs.

NOMENCLATURE

B_o = Oil formation volume factor (FVF), RB/stb
B_{oi} = Initial oil FVF, RB/stb
B_g = Gas FVF, RB/scf
B_{gi} = Initial gas FVF, RB/scf
B_{tg} = Two-phase gas FVF, RB/scf
B_{to} = Two-phase oil FVF, RB/stb
B_w = Water FVF, RB/stb
E_g = Net gas expansion, RB/scf
E_o = Net oil expansion, RB/scf
F = Total hydrocarbon fluid withdrawal, RB
G = Original gas in-place OGIP, scf
G_e = Original gas-equivalent in-place, scf
G_p = Produced wellhead gas, scf

G_{pe} = Produced gas-equivalent, scf
G_{ps} = Produced sales gas, scf
G_{fg} = Gas in free gas-phase, scf
G_{fo} = Gas in free oil-phase, scf
L = Liquid-phase mole fraction
M_o = Stock-tank oil molecular weight,lbs/lbmole
N = OOIP, stb
N_p = Produced oil, stb
N_{fg} = Oil in free gas-phase, stb
N_{fo} = Oil in free oil-phase, stb
N_{foi} = Oil in initial free oil-phase, stb
p = Pressure, psia
p_i = Initial pressure, psia
R_{go} = Gas-equivalent ratio, scf/stb
R_s = Solution gas-oil ratio, scf/stb
R_{si} = Initial solution gas-oil ratio, scf/stb
R_v = Volatile oil-gas ratio, stb/scf
R_{vi} = Initial oil-gas ratio, stb/scf
R_p = Cumulative produced wellhead gas-oil ratio, scf/stb
R_{ps} = Cumulative produced sales gas-oil ratio, scf/stb
r_g = Fraction of produced gas reinjected
S_{wi} = Initial water saturation, fraction PV
S_g = Gas saturation, fraction PV or HCPV
V_p = Reservoir pore volume, RB
V = Vapor-phase mole fraction
V_o = Volume fraction oil-phase
V_{Tg} = Total gas-phase volume, RB
V_{To} = Total oil-phase volume, RB
W_i = Influxed water, stb
W_p = Produced water, stb
ΔW = Definition, see Appendix A
z_i = Initial gas compressibility factor
z_L = Liquid-phase compressibility factor
z_V = Gas-phase compressibility factor
z_2 = Two-phase compressibility factor
z = Gas compressibility factor

Greek

μ_o = Oil viscosity, cp
μ_g = Gas viscosity, cp
ρ_o = Stock-tank oil density, lbs/cf

CONVERSION FACTORS

1 bbl = 0.1590 m^3
1 cf = 0.0283 m^3
1 cp = 0.001 Pa-s
1 psi = 6.894 kPa

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APPENDIX A: DERIVATION OF THE GENERALIZED MATERIAL-BALANCE EQUATION

This appendix derives the generalized material-balance equation (GMBE) and expresses it as an equation of a straight line. Our mathematical development is based on Assumptions 1-14 itemized by Walsh.[1] Following these assumptions, a mass balance on the oil component demands:

(stb of oil in free oil-phase) +
(stb of oil in free gas-phase) =
(initial stb of oil) - (produced stb of oil) (A-1)

or

$$N_{fo} + N_{fg} = N - N_p \qquad \text{(A-1)}$$

where N is the total stb of oil originally in-place (OOIP), N_p is the stb of produced oil, N_{fo} is the stb of oil in the remaining free oil-phase, and N_{fg} is the stb of oil in the remaining gas-phase. N_{fg} is given by

$$N_{fg} = G_{fg} R_v \qquad \text{(A-2)}$$

where G_{fg} is the scf of gas in the remaining free gas-phase.

A gas component mass balance demands:

(scf of gas in free oil-phase) +
(scf of gas in free gas-phase) =
(initial scf of gas) - (produced scf of gas) (A-3)

or

$$G_{fo} + G_{fg} = G - G_p(1 - r_g) \qquad \text{(A-3)}$$

where G_{fo} is the scf of gas in the remaining free oil-phase and r_g is the fraction of the total produced (wellhead) gas (G_p) which is re-injected. The scf of gas in the remaining free oil-phase is given by

$$G_{fo} = N_{fo} R_s \qquad \text{(A-4)}$$

Substitution for N_{fg} in Eqn. (A-1) by Eqn. (A-2) and solving the resulting expression for N_{fo} yields

$$N_{fo} = (N - N_p) - G_{fg} R_v \qquad \text{(A-5)}$$

Substituting this expression into Eqn. (A-4) for N_{fo} and then substituting this result into Eqn. (A-3) for G_{fo} and solving for G_{fg} gives

$$G_{fg} = \frac{G - G_p(1 - r_g) - (N - N_p) R_v}{(1 - R_v R_s)} \qquad \text{(A-6)}$$

Substituting this expression into Eqn. (A-5) for G_{fg} yields

$$N_{fo} = \frac{(N - N_p) - (G - G_{ps}) R_v}{(1 - R_v R_s)} \qquad \text{(A-7)}$$

where we have used G_{ps} to denote the produced sales gas, $G_{ps}=G_p(1-r_g)$. Eqns. (A-1)-(A-7) are general material-balance relationships and they apply to any open or closed system and to any constant- or variable-volume system. If we assume a constant-volume system (reservoir), then a volume balance demands:

V_p = [Volume of free oil-phase] +
[Volume of free gas-phase] +
[Volume of free water-phase] (A-8)

where V_p is the system pore volume. If we apply Eqn (A-8) to some time after initial production, it yields

$$V_p = N_{fo} B_o + G_{fg} B_g + V_p S_w \qquad \text{(A-9)}$$

where S_w is the water saturation, and the remaining variables have already been defined or are defined in the nomenclature. The reservoir volume of free water-phase at any time V_pS_w is equal to the initial free water volume V_pS_{wi} plus the net increase in the water volume. The net increase in the water volume is equal to $\Delta W=(W_i-W_p)B_w$, where W_i is the stb of influxed water and W_p is the stb of produced water. These substitutions in Eqn. (A-9) give

$$V_p = N_{fo} B_o + G_{fg} B_g + V_p S_{wi} + \Delta W \qquad \text{(A-10)}$$

Substitution for N_{fo} by Eqn. (A-7) and for G_{fg} by Eqn. (A-6) and rearranging gives

$$V_p(1 - S_{wi}) = \frac{(B_o - R_s B_g)(N - N_p) + (B_g - R_v B_o)(G - G_{ps})}{(1 - R_v R_s)} + \Delta W \qquad \text{(A-11)}$$

More broadly, Eqn. (A-11) represents a mass balance for a constant-volume system. To simplify Eqn. (A-11), we introduce the following. R_{ps} is the cumulative produced sales gas GOR which is given by

$$R_{ps} = \frac{G_p(1 - r_g)}{N_p} = \frac{G_{ps}}{N_p} \qquad \text{(A-12)}$$

The OOIP, N, and the OGIP, G, are given by

$$N = N_{foi} + G_{fgi} R_{vi} \tag{A-13}$$

$$G = G_{fgi} + N_{foi} R_{si} \tag{A-14}$$

where N_{foi} is the stb of oil in the original (initial) free oil-phase and G_{fgi} is the scf of gas in the original free gas-phase. If we solve Eqn. (A-10) for the hydrocarbon pore volume $V_p(1-S_{wi})$ and apply Eqn. (A-10) at the initial time, then it becomes:

$$V_p(1 - S_{wi}) = B_{oi} N_{foi} + B_{gi} G_{fgi} \tag{A-15}$$

Substituting Eqns. (A-12) - (A-15) into Eqn. (A-11) and rearranging gives

$$F = N_{foi} E_o + G_{fgi} E_g + \Delta W \tag{A-16}$$

where

$$F = N_p \left[\frac{B_o(1 - R_v R_{ps}) + (R_{ps} - R_s) B_g}{(1 - R_v R_s)} \right] \tag{A-17}$$

$$E_o = B_{to} - B_{oi} \tag{A-18}$$

$$E_g = B_{tg} - B_{gi} \tag{A-19}$$

where B_{to} and B_{tg} are the two-phase oil and gas formation volume factors (FVF), respectively; where

$$B_{to} = \frac{B_o(1 - R_v R_{si}) + B_g(R_{si} - R_s)}{(1 - R_v R_s)} \tag{A-20}$$

$$B_{tg} = \frac{B_g(1 - R_s R_{vi}) + B_o(R_{vi} - R_v)}{(1 - R_v R_s)} \tag{A-21}$$

Physically, B_{to} represents the total volume of oil- plus gas-phases resulting from the expansion of a unit volume of initially-saturated oil-phase and B_{tg} represents the total volume of oil- plus gas-phases resulting from the expansion of a unit volume of initially-saturated gas-phase. Typically B_{to} and B_{tg} are expressed in units of RB/stb and RB/scf, respectively. The GMBE is given by Eqns. (A-16) - (A-21). We purposely neglect secondary production mechanisms such as water and rock compressibility. We neglect these factors for the sake of simplicity; however, our development is easily adaptable to include these and other phenomena.

Black-Oil and Dry-Gas. For the special case of neglecting volatilized-oil, R_v approaches zero and the definitions in Eqns. (A-17), (A-20) and (A-21) simplify to:

$$F = N_p[B_o + (R_{ps} - R_s) B_g] \tag{A-22}$$

$$B_{to} = B_o + B_g (R_{si} - R_s) \tag{A-23}$$

$$B_{tg} = B_g \tag{A-24}$$

Except for minor notation differences, Eqns. (A-16), (A-18), (A-19), and (A-22) - (A-24) were previously introduced by Havlena and Odeh;[9] we collectively refer to them as the conventional material-balance equation (CMBE).

Dry-Gas. For the special case of a strictly dry-gas reservoir: no initial reservoir oil-phase exists ($N_{foi}=0$), the reservoir gas-phase contains no volatile-oil ($R_v=0$), and no stock-tank oil production occurs ($N_p=0$), and Eqn. (A-16) simplifies to:

$$F = G E_g + \Delta W \tag{A-25}$$

where the expressions for F and E_g in Eqns. (A-17) and (A-19) simplify to:

$$F = G_{ps} B_g \tag{A-26}$$

$$E_g = B_g - B_{gi} \tag{A-27}$$

By substituting Eqns. (A-26) and (A-27) into Eqn. (A-25) and assuming a volumetric reservoir, one obtains:

$$G_{ps} B_g = G (B_g - B_{gi}) \tag{A-28}$$

By noting that B_g is proportional to z/p, where z is the gas compressibility factor, Eqn. (A-28) becomes

$$\frac{G_{ps}}{G} = 1 - \frac{\left(\frac{p}{z}\right)}{\left(\frac{p_i}{z_i}\right)} \tag{A-29}$$

where the subscript i denotes initial values. Eqn. (A-29) yields the well-known result that a plot of p/z vs. G_{ps} yields a straight line and its x-intercept yields the OGIP (G).

APPENDIX B: APPLYING MATERIAL BALANCE TO A CONSTANT COMPOSITION EXPANSION

This appendix derives the necessary relationships to predict a constant composition expansion (CCE) based on material balance.

Eqns. (A-6) and (A-7) are general expressions and they apply to an open or closed system and to a constant- or variable-volume system. Appendix A applies them to a constant-volume, open system. We apply them here to a variable-volume, closed system to model a constant composition expansion. A closed system implies no withdrawal, thus $N_p=0$ and $G_p=0$. Accordingly, Eqns. (A-9) and (A-10) become

$$G_{fg} = \frac{G - N R_v}{(1 - R_v R_s)} \tag{B-1}$$

$$N_{fo} = \frac{N - G R_v}{(1 - R_v R_s)} \tag{B-2}$$

The total free gas and oil-phase volumes, V_{Tg} and V_{To}, in a closed system are given by

$$V_{Tg} = G_{fg} B_g = \frac{\left(1 - \frac{R_s}{R_{si}}\right) G B_g}{(1 - R_v R_s)} \qquad \text{(B-3)}$$

$$V_{To} = N_{fo} B_o = \frac{(1 - R_{si} R_s) N B_o}{(1 - R_v R_s)} \qquad \text{(B-4)}$$

where we have used $G/N = R_{si}$ to simplify these expressions. The volume fraction of oil V_o in a CCE is

$$V_o = \frac{V_{To}}{V_{To} + V_{Tg}} = \frac{1}{1 + \frac{B_g (R_{si} - R_s)}{B_o (1 - R_{si} R_v)}} \qquad \text{(B-5)}$$

If we ignore volatilized-oil, $R_v = 0$ and Eqn. (B-5) becomes:

$$V_o = \frac{1}{1 + \frac{B_g (R_{si} - R_s)}{B_o}} \qquad \text{(B-6)}$$

Table 1

Fluid and Reservoir Properties

FLUID PROPERTIES	BLACK-OIL	VOLATILE-OIL	RICH GAS-CONDENSATE	LEAN GAS-CONDENSATE
Molecular Weight (MW), lb/lb mole	81.18	46.69	35.52	26.07
Initial Reservoir Pressure, psia	2,000	5,000	5,800	8,000
Upper Saturation Pressure, psia	1,688	4,677	5,430	7,255
Lower Saturation Pressure, psia	—	—	—	26.0
Reservoir Temperature, °F	131	246	215	215
Reservoir Depth, ft	6,700	10,000	12,800	—
Fluid Viscosity at Initial Pressure, cp	0.3201	0.0735	0.0612	0.049
Separator Pressure, psia	100	500	600	600
Separator Gas MW, lb/lb mole	30.68	21.92	21.7	22.17
Initial GOR, scf/stb	838.5	2,909.4	6,042	22,527
Initial FVF, RB/stb	1.467	2.713	4.382	12.732
Stock Tank Oil Gravity, API	38	44	36	39
Stock Tank Oil MW, lb/lb mole	151.43	141.15	141.65	132.17
Stock Tank Oil Density, lb/cu. ft	52.10	50.30	52.58	51.72
Gas Equivalent R_{go}, scf/stb	746.96	759.04	790.59	833.48
Composition, mole fraction				
N_2	0.0028	0.0167	0.0223	0.02399
C_1	0.2925	0.6051	0.6568	0.70654
CO_2	0.0020	0.0218	0.0045	0.00484
C_2	0.1044	0.0752	0.1170	0.12586
C_3	0.1214	0.0474	0.0587	0.06315
i-C_4	0.0057	0.0000	0.0127	0.01366
n-C_4	0.0608	0.0412	0.0168	0.01807
i-C_5	0.0148	0.0000	0.0071	0.00764
n-C_5	0.0296	0.0297	0.0071	0.00764
C_6	0.0345	0.0138	0.0098	0.01054
C_{7+}	0.3315	0.1491	0.0872	0.01807

Table 2: BLACK-OIL

Table 2a—Fluid Properties

P psia	B_o, RB/stb	B_g, RB/Mscf	R_s, scf/stb	R_v, stb/MMscf	μ_o, cp	μ_g, cp	E_o, RB/stb	Z_V	Z_L	Z_2
2000	1.467	1.749	838.5	1192.6	0.3201	0.3201	0.0000	0.6054	0.6054	0.6054
1800	1.472	1.755	838.5	1192.6	0.3114	0.3114	0.0052	0.5469	0.5469	0.5469
1700	1.475	1.758	838.5	1192.6	0.3071	0.3071	0.0080	0.5174	0.5174	0.5174
1640	1.463	1.921	816.1	0.2	0.3123	0.0157	0.0394	0.7948	0.5027	0.5064
1600	1.453	1.977	798.4	0.2	0.3160	0.0155	0.0659	0.7977	0.4932	0.5007
1400	1.408	2.308	713.4	0.0	0.3400	0.0140	0.2305	0.8134	0.4439	0.4722
1200	1.359	2.730	621.0	0.0	0.3710	0.0138	0.4863	0.8300	0.3933	0.4516
1000	1.322	3.328	548.0	0.0	0.3970	0.0132	0.8229	0.8503	0.3374	0.4295
800	1.278	4.163	464.0	0.0	0.4320	0.0126	1.3694	0.8708	0.2800	0.4181
600	1.237	5.471	383.9	0.0	0.4710	0.0121	2.2572	0.8934	0.2187	0.4139
400	1.194	7.786	297.4	0.0	0.5180	0.0116	3.9427	0.9184	0.1535	0.4250
200	1.141	13.331	190.9	0.0	0.5890	0.0108	8.3070	0.9484	0.0830	0.4701

Table 2b—Reservoir Performance

Pressure, psia	P/Z_2, psia	Oil Recovery, %OOIP	Gas Recovery, %OGIP	Producing GOR, Mscf/stb	Cumulative GOR, R_{ps} Mscf/stb	S_g, %HCPV	F,* RB	E_o, RB/stb	G_{pe}/G_e,%
2000	3303.38	0.0	0.0	0.84	0.84	0.0	0.0000	0.0000	0.00
1800	3291.52	0.4	0.4	0.84	0.84	0.0	0.0052	0.0052	0.35
1700	3285.41	0.5	0.5	0.84	0.84	0.0	0.0080	0.0080	0.54
1640	3236.31	2.7	2.6	0.82	0.83	2.9	0.0394	0.0394	2.64
1600	3195.45	4.4	4.3	0.80	0.82	5.3	0.0660	0.0659	4.36
1400	2964.83	11.3	13.3	1.41	0.99	14.8	0.2304	0.2305	12.35
1200	2656.93	16.1	23.6	2.17	1.23	22.3	0.4862	0.4863	20.14
1000	2328.44	19.3	33.0	2.70	1.43	27.3	0.8228	0.8229	26.66
800	1913.60	22.2	43.4	3.52	1.64	32.2	1.3697	1.3694	33.59
600	1449.57	24.3	53.8	4.58	1.85	36.2	2.2569	2.2572	40.17
400	941.23	26.2	64.9	5.56	2.08	39.9	3.9423	3.9427	46.97
200	425.41	27.9	77.8	6.79	2.34	43.9	8.3073	8.3070	54.76

* Normalized by the stb of OOIP

Table 3: VOLATILE-OIL

Table 3a—Fluid Properties

P psia	B_o, RB/stb	B_g, RB/Mscf	R_s, scf/stb	R_v, stb/MMscf	μ_o, cp	μ_g, cp	E_o, RB/stb	Z_V	Z_L	Z_2
4998	2.713	0.932	2909	343.0	0.0735	0.0735	0.0000	1.0436	1.0436	1.0436
4798	2.740	0.942	2909	343.0	0.0716	0.0716	0.0270	1.0118	1.0118	1.0118
4698	2.754	0.947	2909	343.0	0.0706	0.0706	0.0410	0.9957	0.9957	0.9957
4658	2.707	0.830	2834	116.0	0.0718	0.0375	0.0517	0.9551	0.9924	0.9911
4598	2.631	0.835	2711	111.0	0.0739	0.0367	0.0704	0.9499	0.9878	0.9846
4398	2.338	0.853	2247	106.0	0.0847	0.0350	0.1483	0.9313	0.9783	0.9661
4198	2.204	0.874	2019	94.0	0.0906	0.0327	0.2191	0.9170	0.9570	0.9440
3998	2.093	0.901	1828	84.0	0.0968	0.0306	0.3049	0.9049	0.9340	0.9231
3798	1.991	0.933	1651	74.0	0.1028	0.0288	0.3996	0.8947	0.9086	0.9028
3598	1.905	0.970	1500	66.0	0.1104	0.0271	0.5123	0.8859	0.8834	0.8845
3398	1.828	1.015	1364	60.0	0.1177	0.0255	0.6300	0.8790	0.8555	0.8670
3198	1.758	1.066	1237	54.0	0.1242	0.0240	0.7920	0.8735	0.8241	0.8495
2998	1.686	1.125	1111	49.0	0.1325	0.0227	0.9456	0.8695	0.7927	0.8344
2798	1.632	1.196	1013	44.0	0.1409	0.0214	1.1578	0.8673	0.7589	0.8203
2598	1.580	1.281	918	39.0	0.1501	0.0203	1.3829	0.8664	0.7233	0.8077
2398	1.534	1.380	833	36.0	0.1598	0.0193	1.6563	0.8669	0.6856	0.7964
2198	1.490	1.498	752	33.0	0.1697	0.0184	1.9861	0.8694	0.6451	0.7865
1998	1.450	1.642	677	30.0	0.1817	0.0175	2.3743	0.8732	0.6035	0.7790
1798	1.413	1.819	608	28.0	0.1940	0.0168	2.8677	0.8785	0.5590	0.7729
1598	1.367	2.035	524	26.0	0.2064	0.0161	3.4765	0.8852	0.5112	0.7681
1398	1.333	2.315	461	25.0	0.2223	0.0155	4.2583	0.8933	0.4619	0.7664
1198	1.305	2.689	406	24.1	0.2438	0.0150	5.3121	0.9026	0.4112	0.7686
998	1.272	3.190	344	23.9	0.2629	0.0146	6.7306	0.9137	0.3549	0.7713
798	1.239	3.911	283	24.4	0.2882	0.0142	8.7851	0.9260	0.2958	0.7782
598	1.205	5.034	212	26.4	0.3193	0.0138	12.0480	0.9399	0.2323	0.7892

Table 3b—Reservoir Performance

Pressure, psia	P/Z_2, psia	Oil Recovery, %OOIP	Gas Recovery, %OGIP	Producing GOR, Mscf/stb	Cumulative GOR, R_{ps} Mscf/stb	S_g, %HCPV	F,* RB	E_o, RB/stb	G_{pe}/G_e,%
4998	4789.19	0.0	0.0	2.91	2.91	0.0	0.0000	0.0000	0.00
4798	4742.04	1.0	1.0	2.91	2.91	0.0	0.0271	0.0270	0.99
4698	4718.29	1.5	1.5	2.91	2.91	0.0	0.0410	0.0410	1.49
4658	4699.66	1.9	1.9	2.83	2.90	3.4	0.0516	0.0517	1.87
4598	4670.02	2.6	2.5	2.75	2.87	8.5	0.0705	0.0704	2.53
4398	4552.49	5.3	5.2	2.97	2.86	25.9	0.1482	0.1483	5.19
4198	4446.99	7.4	7.5	3.45	2.96	32.5	0.2190	0.2191	7.47
3998	4331.22	9.4	10.3	4.41	3.17	37.4	0.3049	0.3049	10.09
3798	4206.84	11.1	13.2	5.76	3.45	41.3	0.3994	0.3996	12.81
3598	4067.64	12.6	16.5	7.49	3.82	44.4	0.5122	0.5123	15.84
3398	3919.27	13.7	19.7	8.97	4.19	47.0	0.6300	0.6300	18.80
3198	3764.40	14.9	23.8	10.59	4.64	49.2	0.7922	0.7920	22.52
2998	3593.16	15.8	27.3	12.60	5.03	51.5	0.9456	0.9456	25.81
2798	3410.92	16.7	31.6	14.66	5.49	53.1	1.1578	1.1578	29.78
2598	3216.72	17.5	35.6	17.22	5.93	54.6	1.3828	1.3829	33.55
2398	3011.10	18.1	39.9	19.70	6.40	56.0	1.6558	1.6563	37.57
2198	2794.65	18.8	44.3	21.96	6.87	57.3	1.9857	1.9861	41.73
1998	2564.77	19.3	48.7	24.39	7.33	58.4	2.3748	2.3743	45.91
1798	2326.16	19.8	53.3	26.37	7.81	59.5	2.8673	2.8677	50.28
1598	2080.39	20.3	58.0	28.79	8.30	60.9	3.4765	3.4765	54.87
1398	1824.00	20.8	62.7	30.33	8.77	62.0	4.2579	4.2583	59.36
1198	1558.64	21.3	67.4	31.69	9.23	62.9	5.3133	5.3121	63.91
998	1293.88	21.7	72.2	32.29	9.69	63.9	6.7302	6.7306	68.53
798	1025.50	22.1	77.0	32.13	10.13	64.9	8.7853	8.7851	73.20
598	757.76	22.6	82.2	30.42	10.58	66.0	12.0498	12.0480	78.18

* Normalized by the stb of OOIP

Table 4: RICH GAS-CONDENSATE

Table 4a—Fluid Properties

P psia	B_o, RB/stb	B_g, RB/Mscf	R_s, scf/stb	R_v, stb/MMscf	μ_o, cp	μ_g, cp	E_o, RB/stb	Z_V	Z_L	Z_2
5800	4.382	0.725	6042	165.5	0.0612	0.0612	0.0000	1.0896	1.0896	1.0896
5550	4.441	0.735	6042	165.5	0.0620	0.0620	0.0590	1.0570	1.0570	1.0570
5450	4.468	0.739	6042	165.5	0.0587	0.0587	0.0860	1.0439	1.0439	1.0439
5420	2.378	0.740	2795	164.2	0.1350	0.0581	0.0936	1.0395	1.1329	1.0403
5300	2.366	0.743	2750	156.6	0.1338	0.0554	0.1204	1.0217	1.1148	1.0261
4800	2.032	0.758	2128	114.0	0.1826	0.0436	0.3803	0.9552	1.0438	0.9706
4300	1.828	0.794	1730	89.0	0.2354	0.0368	0.6432	0.9033	0.9799	0.9198
3800	1.674	0.854	1422	65.2	0.3001	0.0308	1.0645	0.8648	0.9039	0.8741
3300	1.554	0.947	1177	48.3	0.3764	0.0261	1.6852	0.8384	0.8254	0.8354
2800	1.448	1.090	960	35.0	0.4781	0.0222	2.5315	0.8264	0.7382	0.8069
2300	1.360	1.313	776	25.0	0.6041	0.0191	3.8304	0.8300	0.6413	0.7907
1800	1.279	1.677	607	19.0	0.7746	0.0166	6.0007	0.8466	0.5359	0.7882
1300	1.200	2.316	443	15.0	1.0295	0.0148	9.7931	0.8744	0.4198	0.8009
800	1.131	3.695	293	13.5	1.3580	0.0135	17.9589	0.9127	0.2861	0.8303

Table 4b—Reservoir Performance

Pressure, psia	P/Z_2, psia	Oil Recovery, %OOIP	Gas Recovery, %OGIP	Producing GOR, Mscf/stb	Cumulative GOR, R_{ps} Mscf/stb	S_g, %HCPV	F,* RB	E_o, RB/stb	G_{pe}/G_e,%
5800	5323.05	0.0	0.0	6.04	6.04	100.0	0.0000	0.0000	0.00
5550	5250.96	1.3	1.3	6.04	6.04	100.0	0.0577	0.0590	1.33
5450	5220.91	1.9	1.9	6.04	6.04	100.0	0.0849	0.0860	1.92
5420	5210.11	2.1	2.1	6.09	6.04	99.2	0.0940	0.0936	2.09
5300	5165.08	2.6	2.7	6.39	6.12	95.0	0.1180	0.1204	2.69
4800	4945.47	7.0	8.1	8.77	7.00	81.8	0.3801	0.3803	7.99
4300	4674.88	10.1	13.1	11.22	7.90	78.7	0.6467	0.6432	12.83
3800	4347.19	13.3	20.2	15.29	9.18	76.7	1.0652	1.0645	19.65
3300	3950.27	16.2	28.7	20.62	10.73	76.3	1.6874	1.6852	27.84
2800	3469.97	18.4	37.8	28.45	12.39	76.6	2.5282	2.5315	36.63
2300	2908.75	20.2	47.8	39.82	14.30	77.2	3.8295	3.8304	46.35
1800	2283.77	21.6	58.7	52.42	16.40	78.3	5.9902	6.0007	56.99
1300	1623.09	22.8	69.7	66.48	18.50	79.5	9.8143	9.7931	67.77
800	963.54	23.7	80.5	73.99	20.53	80.6	17.9627	17.9589	78.39

* Normalized by the stb of OOIP

Table 5: LEAN GAS-CONDENSATE

Table 5a—Fluid Properties

P psia	B_o, RB/stb	B_g, RB/Mscf	R_s, scf/stb	R_v, stb/MMscf	μ_o, cp	μ_g, cp	E_o, RB/stb	Z_V	Z_L	Z_2
8000	12.732	0.565	22527	44.4	0.049	0.0490	0.0000	1.2765	1.2765	1.2765
7500	13.044	0.579	22527	44.4	0.047	0.0470	0.3120	1.2261	1.2261	1.2261
7280	13.192	0.586	22527	44.4	0.046	0.0460	0.4630	1.2039	1.2039	1.2039
7250	1.054	0.587	860	44.3	19.541	0.0460	0.5625	1.2009	2.3350	1.2009
7000	1.041	0.595	819	43.9	20.965	0.0449	0.7935	1.1755	2.3018	1.1762
6500	1.018	0.613	754	40.3	23.958	0.0420	1.0655	1.1251	2.1634	1.1270
6000	1.002	0.634	704	36.5	26.338	0.0393	1.5649	1.0754	1.9949	1.0784
5500	0.983	0.661	648	32.9	29.633	0.0366	2.2857	1.0267	1.8501	1.0302
5000	0.965	0.694	593	29.2	33.319	0.0339	3.0080	0.9795	1.6623	0.9832
4500	0.947	0.737	541	25.4	37.401	0.0312	4.1778	0.9345	1.4614	0.9386
4000	0.930	0.795	490	21.4	42.161	0.0283	5.5742	0.8937	1.2533	0.8979
3500	0.913	0.877	440	17.6	47.465	0.0254	7.4146	0.8596	1.0694	0.8632
3000	0.896	0.997	389	13.7	53.765	0.0225	10.1497	0.8345	0.9278	0.8365
2500	0.877	1.178	336	10.5	61.887	0.0198	14.2210	0.8219	0.7889	0.8211
2000	0.858	1.466	280	7.9	72.143	0.0174	20.7523	0.8262	0.6465	0.8213
1500	0.839	1.963	228	5.8	83.478	0.0154	31.7653	0.8490	0.5094	0.8396
1000	0.819	2.912	169	4.4	99.049	0.0140	53.1196	0.8879	0.3703	0.8751

Table 5b—Reservoir Performance

Pressure, psia	P/Z_2, psia	Oil Recovery, %OOIP	Gas Recovery, %OGIP	Producing GOR, Mscf/stb	Cumulative GOR, R_{ps} Mscf/stb	S_g, %HCPV	F,* RB	E_o, RB/stb	G_{pe}/G_e,%
8000	6266.99	0.0	0.0	22.53	22.53	100.00	0.0000	0.0000	0.00
7500	6116.96	2.4	2.4	22.53	22.53	100.00	0.3120	0.3120	2.39
7280	6046.86	3.5	3.5	22.53	22.53	100.00	0.4630	0.4630	3.51
7250	6036.95	4.2	4.2	22.55	22.52	99.99	0.5625	0.5625	4.21
7000	5951.36	5.8	5.8	22.78	22.53	99.91	0.7935	0.7935	5.84
6500	5767.46	7.6	7.7	24.81	22.80	99.29	1.0621	1.0655	7.70
6000	5564.01	10.4	11.0	27.40	23.66	98.68	1.5615	1.5649	10.93
5500	5338.97	13.8	15.3	30.40	24.91	98.15	2.2829	2.2857	15.21
5000	5085.26	16.6	19.2	34.25	26.11	97.66	3.0044	3.0080	19.10
4500	4794.57	20.0	24.9	39.37	27.95	97.21	4.1752	4.1778	24.68
4000	4454.97	23.1	30.7	46.73	29.93	96.79	5.5712	5.5742	30.39
3500	4054.70	25.9	37.1	56.82	32.28	96.45	7.4127	7.4146	36.69
3000	3586.37	28.5	44.7	72.99	35.29	96.15	10.1455	10.1497	44.13
2500	3044.70	30.8	53.2	95.24	38.86	95.99	14.2199	14.2210	52.36
2000	2435.25	32.7	62.4	126.58	42.97	95.90	20.7514	20.7523	61.31
1500	1786.50	34.1	71.7	172.41	47.36	95.90	31.7598	31.7653	70.38
1000	1142.67	35.2	80.9	227.27	51.84	95.95	53.1129	53.1196	79.25

* Normalized by the stb of OOIP.

Table 6

ERROR SUMMARY

	RESERVOIR FLUID			
	BLACK-OIL	VOLATILE-OIL	RICH GAS-CONDENSATE	LEAN GAS-CONDENSATE
GENERALIZED MATERIAL BALANCE				
Predicted OOIP/Actual OOIP	1.0000	0.9998	1.0008	0.9963
% Error	0.0	0.0	0.1	0.4
CONVENTIONAL MATERIAL BALANCE				
Predicted OOIP/Actual OOIP	1.0000	0.7815	0.4761	0.5928
% Error	0.0	21.8	52.2	40.7
P/Z_2-METHOD				
Predicted OOIP/Actual OOIP	1.3600	1.0500	1.1300	1.0200
% Error	36.0	5.0	13.0	2.0

FIG. 1—Constant composition expansion data

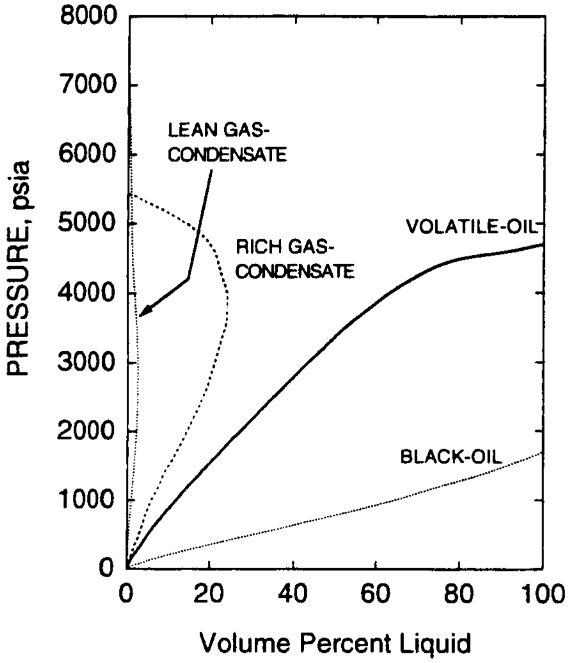

FIG 2—Material balance predictions of black-oil constant composition expansion

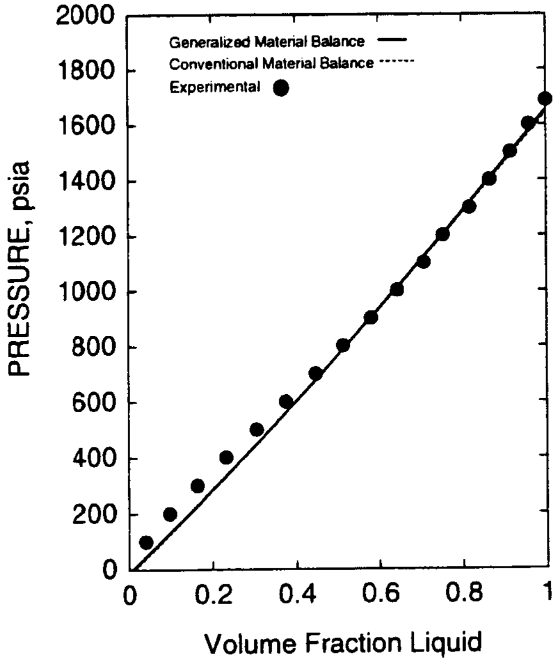

FIG. 3—Material balance predictions of rich gas-condensate constant composition expansion

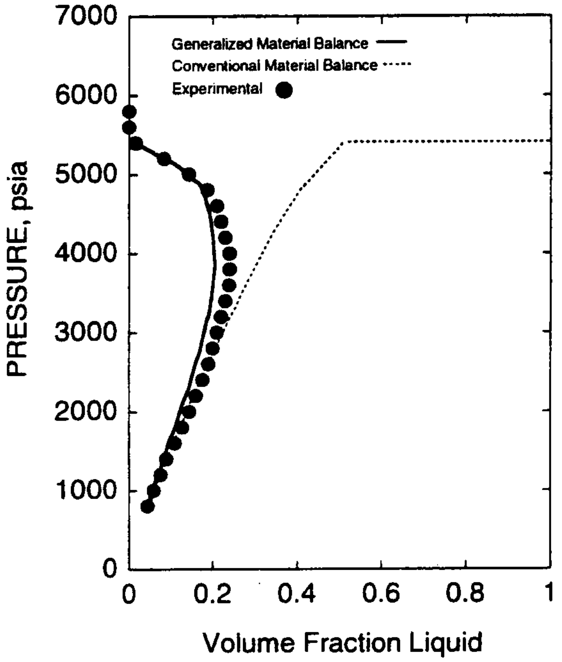

FIG. 4—Gas-oil relative permeability data.

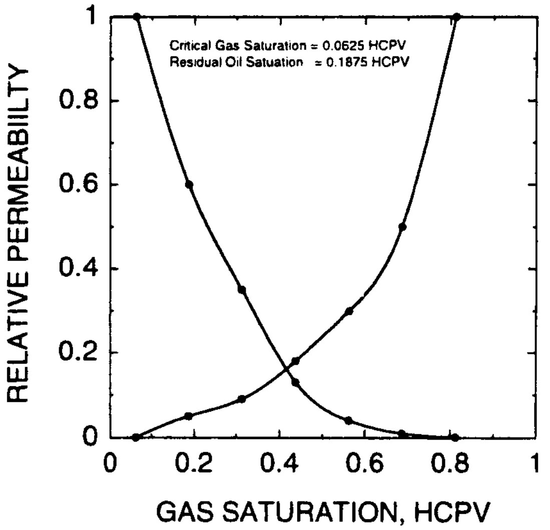

FIG. 5—F vs E_o plots

Fig. 5a—Black-Oil

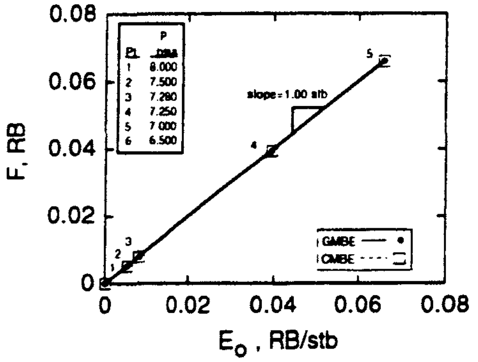

Fig. 5b—Volatile-Oil

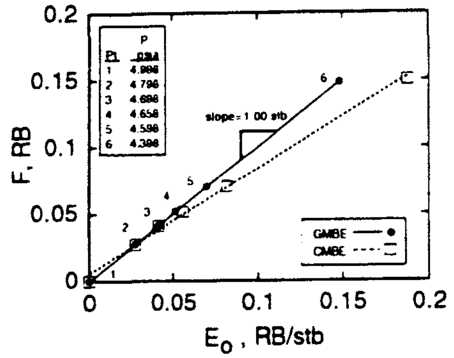

Fig. 5c—Rich Gas-Condensate

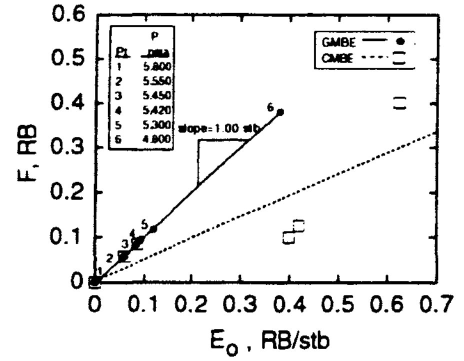

Fig. 5d—Lean Gas-Condensate

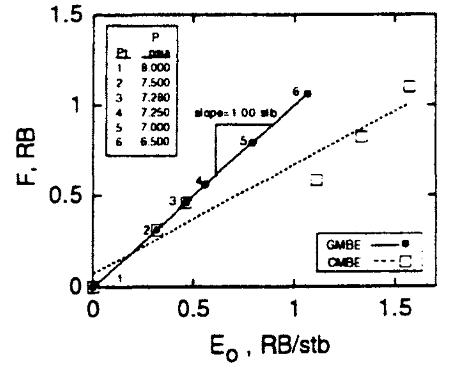

FIG. 6—P/z_2 plots.

Fig. 6a—Black-Oil

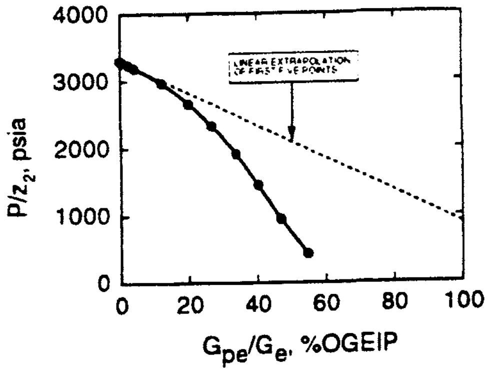

Fig. 6b—Volatile-Oil

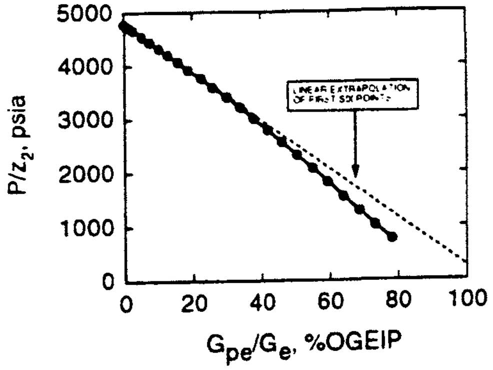

Fig. 6c—Rich Gas-Condensate

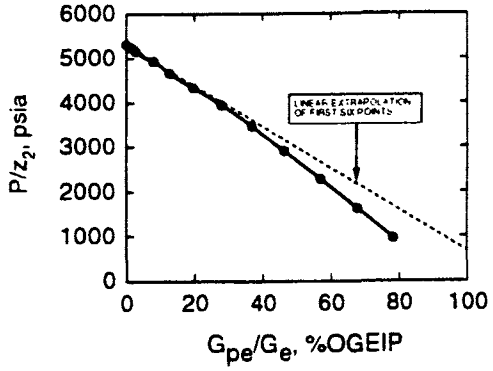

Fig. 6d—Lean Gas-Condensate