Full Length Research Paper

The effects of the volatile oil-gas ratio on reserve estimation (GMBE versus CMBE) in undersaturated volumetric reservoirs

Omoniyi, O. A. and Rodney, C.

Department of Petroleum Engineering Abubakar Tafawa Balewa University Bauchi, Bauchi State, Nigeria.

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. The work supersedes these and it is applicable to the full range of reservoir fluids-including volatile-oils and gas-condensates. The work is based on the new generalized material-balance equation recently introduced by Walsh. 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. Empirical correlations for the volatile oil-gas ratio Rv for volatile-oils and gas-condensates have been introduced to accurately define how much fluid volatility a reservoir oil can exhibit before one can no longer justifiably use the CMBE and one must apply the generalized material balance equation (GMBE). Thus, if there is interest in applying the conventional material-balance equation (CMBE) and its applicability is in question, we recommend measuring the fluid's volatile oil-gas ratio Rv at its saturation pressure and comparing it to the critical value offered herein.

Key words: Volatile oil, undersaturated, volumetric, material balance, reserve estimation, oil-gas ratio, black oil, gas condensate.

INTRODUCTION

Material balance calculations are very well established techniques that apply the law of conservation of matter to petroleum engineering (Penuela et al., 2001). Nevertheless, it seems no longer fashionable to apply the concept of material balance to oil fields, the belief being that it has now been superseded by the application of the more modern technique of numerical simulation modeling. Acceptance of this idea has been a tragedy and has robbed engineers of their most powerful tool for investigating reservoirs and understanding their performance rather than imposing their wills upon them, as it is often the case when applying numerical simulation directly in history matching.

As demonstrated in this work, by defining an average pressure decline trend for a reservoir, which is always possible, irrespective of any lack of pressure equilibrium, then material balance can be applied using simply the production and pressure histories together with the fluid PVT properties. No geometrical considerations (geological models) are involved, hence the material balance can be

used to calculate the hydrocarbons in place and define the drive mechanisms. In this respect, it is the safest technique in the business since it is the minimum assumption route through the subject of reservoir engineering. Conversely, the mere act of construction of a simulation model, using the geological maps and petrophysically determined formation properties implies that the STOIIP is "known". Therefore, history matching by simulation can hardly be regarded as an investigative technique but one that merely reflects the input assumptions of the engineer performing the study.

There should be no competition between material balance and simulation; instead they must be supportive of one another: The former defining the system which is then used as input to the model. Material balance is excellent at history matching production performance but has considerable disadvantages when it comes to prediction, which is the domain of numerical simulation modeling.

Because engineers have drifted away from oilfield material balance in recent years, the unfamiliarity breeds a lack of confidence in its meaningfulness and, indeed, how to use it properly. To counter this, the work provides a comprehensive description of various methods of application of the technique.

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 (Schilthuis, 1936; Dake, 1978; Tarek, 2005; Craft and Hawkins, 1959; Amyx et al., 1960; Pirson, 1958; Muskat, 1949). Unlike the conventional material-balance equation (CMBE), 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 (Walsh, 1994).

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 (Cook et al., 1974; Stone and Garder, 1961). Cook et al. (1974) referred to Rv as the "liquid content of the gas;" Coats et al. (1967) referred to it as the "oil vapor in gas". This variable is distinctly different from but analogous to the dissolved gas-oil ratio, Rs. The volatile oil-gas ratio is a function of the reservoir fluid composition. It is also 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 to 10 stb/mmscf; for volatile-oils, it ranges from 10 to 200 stb/mmscf; for near-critical fluids, it reaches maximum values and ranges from 150 to 400 stb/mmscf; for gas-condensates, it ranges from 50 to 250 stb/mmscf; for wet gases, it ranges from 20 to 100 stb/mmscf; and for dry gases, it approaches zero (Walsh, 1994).

This work leads to a new and improved method of analyzing reservoir performance. Together with Walsh's work (1994) 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.

Problem statement

Application of the CMBE yields erroneous original oil in place estimate (OOIP) for all fluids except the black oil, the CMBE under-predicts the OOIP. The error is directly related to the magnitude of volatile oil-gas ratio Rv.

Objectives of the study

1. To estimate OOIP using the GMBE and CMBE.
2. To determine whether the effects of volatilized-oil are important.
3. To identify whether the GMBE is necessary or the CMBE is sufficient.

Significance of the study

It is not clear as to how much fluid-volatility Rv 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, this work defined these limits.

Limitation

The estimation and investigation is restricted to under-saturated, volumetric reservoirs and fluids types of:

1. Black oil
2. Volatile oil, and
3. Gas condensates

METHODOLOGY

The mathematical base of this work is the new generalized material balance equation GMBE. The GMBE by Walsh (1994), which is the modified CMBE as applied to reserve estimation in gas-condensate and volatile reservoirs. A mass balance over a constant-volume system which initially contains free oil- and gas-phases demands (Walsh, 1994):

$$F = N f_{oi} + G f_{gi} E_g + \Delta W \qquad (1)$$

Where Nfoi is the stb of stock-tank oil originally in the free oil phase; Gfgi is the scf of surface-gas originally in the free gas phase; F is the RB of total hydrocarbon fluid withdrawal; Eo is the net expansion of the original free oil-phase expressed as RB/stb; Eg 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 Nfoi and Gfgi are constants and F, Eo. Eg, and ΔW are functions of pressure. If we account for volatilized-oil in the reservoir gas phase, then F, Eo, and Eg are defined by:

$$F = Np \left[\frac{Bo(1-RvRps)+(Rps-Rs)Bg}{(1-RvRs)} \right] \qquad (2a)$$

$$Eo = \frac{(Bo-Boi)+Bg(Rsi-Rs)+Rv(BoiRs-BoRsi)}{(1-RvRs)} \qquad (2b)$$

$$Eg = \frac{(Bg-Bgi)+Bo(Rvi-Rv)+Rs(BgiRv-BgRvi)}{(1-RvRs)} \qquad (2c)$$

Where Np is the stb of cumulative produced oil and Rps is the ratio of the scf of cumulative produced sales gas (Gps) and the stb of cumulative produced oil (Np).

The cumulative produced sales gas is equal to the cumulative produced wellhead gas if and only if there is no gas re-injection. If Bo, Bg, Rs and Rv have units of RB/stb, RB/scf, scf/stb, and stb/scf, respectively, then Equations (1) and (2) are applicable as written and require no conversion factors. The remaining variables (with units) are defined in the nomenclature. Collectively, Equations (1) and (2) represent the GMBE. Equations (1) and (2) have been presented before except in a slightly different algebraic form and for the case of only initially-under saturated reservoirs (Walsh, 1994).

The development is more general and considers initially-saturated or initially-under saturated reservoirs. If we ignore volatilized-oil, then F, Eo, and Eg are defined by:

$$F=Np[Bo+(Rps-Rs)Bg] \qquad (3a)$$

$$Eo=Bo-Boi+Bg(Rsi-Rs) \qquad (3b)$$

$$Eg=Bg-Bg \qquad (3c)$$

Collectively, Equations (1) and (3) represent the CMBE and their application has been thoroughly discussed by Havlena and Odeh (1963).

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 Equations (3) are identical to those originally proposed by Havlena and Odeh (1963) except that they defined F to be the total fluid (hydrocarbon plus water) withdrawal and F is defined here 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 Equation (3) is applied to reservoir fluids containing volatilized-oil, it will yield erroneous estimates of F, Eo, and Eg. These errors, in turn, will yield errors in estimating the OOIP and OGIP. If Equation (3) yields an error, then it will usually, but not exclusively, over predict F and Eo and Under predict Eg (Walsh, 1994)

It is important to recognize that the constants Nfoi and Gfgi and Equation (1) are not generally equal to the OOIP (N) and OGIP (G), respectively. Most generally, these quantities are related to one another by:

$$N=Nfoi+GfgiRvi \qquad (4)$$

$$G=Gfgi+NfoiRsi \qquad (5)$$

Where the products GfgiRvi and NfoiRsi 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, Nfoi and Gfgi are equal to the OOIP and OGIP, respectively. For example, Nfoi is equal to the OOIP if the reservoir fluid is an initially-undersaturated oil (Gfgi=O). Likewise, Gfgi is equal to OGIP if the reservoir fluid is an initial-undersaturated gas reservoir (Nfoi=O). In Havlena and Odeh (1963) work, for example, Nfoi was always equal to the OOIP (N) because they ignored volatilized-oil, that is, they assumed Rv was negligible.

Undersaturated fluids

Equations (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:

$$G=Gfgi+NfoiRsi \qquad (6a)$$

$$F=GpsBg \qquad (6b)$$

$$Eo=Bo-Boi \qquad (7)$$

$$Eg=Bg-Bgi \qquad (8)$$

These equations apply regardless of whether one includes or ignores volatilized-oil. Notice that Equation (6) gives two alternative methods to compute F. Equations (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 oil and its fluid properties are given in terms of Bo's, then application of Equation (6a) is the logical choice. On the other hand, if the single-phase fluid properties are given in terms of Bg's, then application of Equations (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 (Stone and Garder, 1961).

For the special case of a single-phase fluid, Bo is related to Bg by:

$$Bo = \frac{Bg}{Rv} \qquad (9)$$

And Rs is related to Rv by:

$$Rs = \frac{1}{Rv} \qquad (10)$$

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, Rps. is equal to the solution gas-oil ratio Rs:

$$Rps = \frac{Gps}{Np} = Rs \qquad (11)$$

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

The relationships given collectively by Equations (1) and (2) and Equations (6) to (8) are quite general and are applicable to a wide range of reservoir conditions (Walsh, 1994).

Initially-undersaturated, volumetric oil reservoirs

If we apply Equation (1) to an initially-undersaturated, volumetric oil reservoir, then Nfoi=N. Gfgi=O and ∆W=O and we obtain:

$$F = NEo \tag{12}$$

Where F and Eo are given by Equations (6a) and (7) if the pressure is greater than the saturation pressure and are given by Equation (2) if the pressure is less than or equal to the saturation pressure.

Equation (12) reveals that a plot of F vs. Eo yields a straight line which passes through the origin and whose slope is equal to N. The OGIP is computed by knowing G=RsiN (Walsh, 1994).

Initially-undersaturated, volumetric gas reservoirs

Alternatively, if we apply Equations (1) to an initially-undersaturated, volumetric gas reservoir, then Gfgi=G, Nfoi=O and ∆W=O and we obtain:

$$F = GEg \tag{13}$$

Where F and Eg are given by Equations (6b) and (8) if the pressure is greater than the saturation pressure and are given by Equations (2) if the pressure is less than or equal to the saturation pressure.

Equations (13) reveals that a plot of F vs. Eg yields a straight line which passes through the origin and whose slope is equal to G. The OOIP is computed by knowing N=RviG.

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

Determination of the fluids volatile oil-gas ratio R_V

The oil-gas ratio R_V, a completely new form was suggested for the oil-gas ratio correlation after trying different forms and combination of parameters. For the correlation to be useful and have wide application, all parameters selected in the correlation have to be readily available without the need for fluid samples or elaborate calculation procedures using EOS models. The form given by Equation (14) was suggested. The average error using this form is 10.4% with a standard deviation of 0.0308 for gas condensates and 15.0% with 0.1271 standard deviation for volatile oils (El-Banbi et al., 2006):

$$Rv = \frac{A1 \times \rho g sc \times (A2 \times P^4 + A3 \times P + A4)}{Ps} EXP \frac{A5 \times CGR \times T}{\rho o sc \times T \times Psc} \tag{14}$$

Volatile oil-gas ratio (R_V) for single phase fluids

For the special case of a single phase fluid, RV is related to Rs by:

$$Rs = \frac{1}{Rv} \tag{15}$$

This equation follows from the observation that the distinction between either an oil or gas phase is superfluous if only a single hydrocarbon phase exists.

$$Rs = \gamma g \left[\left(\frac{p}{A1} + A2 \right) 10^x \right] A3 \tag{16}$$

$$X = A4 \times API - A5(T - 460) \tag{17}$$

Substituting Equation (16) into (15) and solving for RV:

$$Rv = \frac{1}{\gamma \left[\left(\frac{P}{A1} + A2 \right) 10^x \right] A3} \tag{18}$$

RESULTS AND DISCUSSION

The result of applying GMBE to the fluids for black-oil, volatile-oil, rich gas-condensate and lean gas-condensate are given in Figures 1 to 4 while that of the application of CMBE to the fluids for black-oil, volatile-oil, rich gas-condensate and lean gas-condensate are represented in Figures 5 to 8. The volatile oil-gas ratio Rv is given in Table 1. Volatile oil-gas ratio for single phase fluids is given as follows:

Gas condensate:

A1	A2	A3	A4	A5
0.19408473	-3709.42	1.060521	-0.05022	-0.00377

X
 -3.43521062
Rs
 988.4335628 scf/stb
Rv
 1011.701785 MMstb/scf

Volatile oil:

A1	A2	A3	A4	A5
47.23306	-8.83351	1.325153	0.009176	-0.00039

X
 0.376277864
Rs
 551.2558408 scf/stb
Rv
 1814.039736 MMstb/scf

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 (N) 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 (N) of 1 stb. Only the early-time production data points are used because reservoir engineers are most interested in determining reserves early rather than late in the reservoir's life.

The plots of F vs. Eo 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 Rv is sufficiently small and the GMBE and CMBE are equivalent for this case (Equations (2) and (3)).

Figure 1. Plot of F vs Eo for black oil using the GMBE.

Figure 2. Plot of F vs Eo for volatile oil using the GMBE.

Figure 3. Plot of F vs Eg for rich gas condensate using the GMBE.

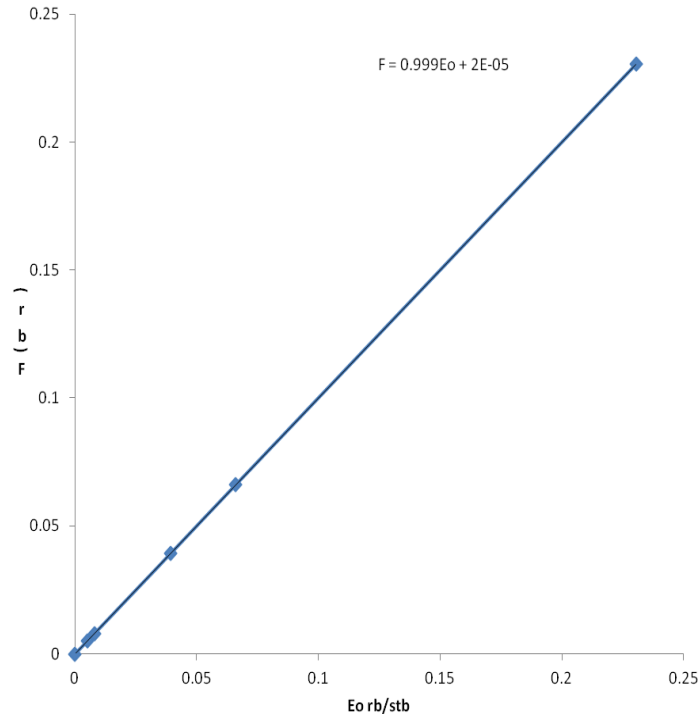**Figure 4.** Plot of F vs Eg for lean gas condensate using the GMBE.

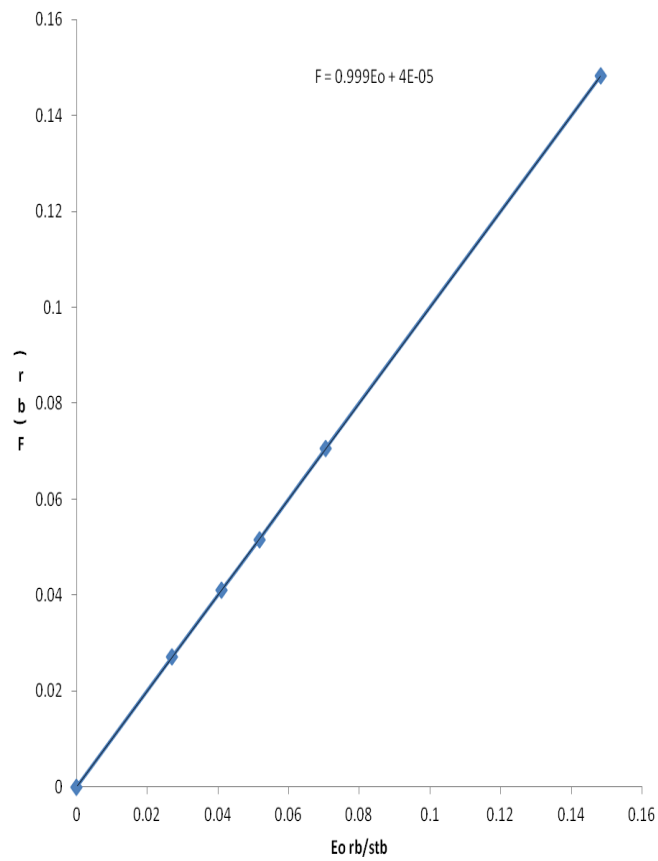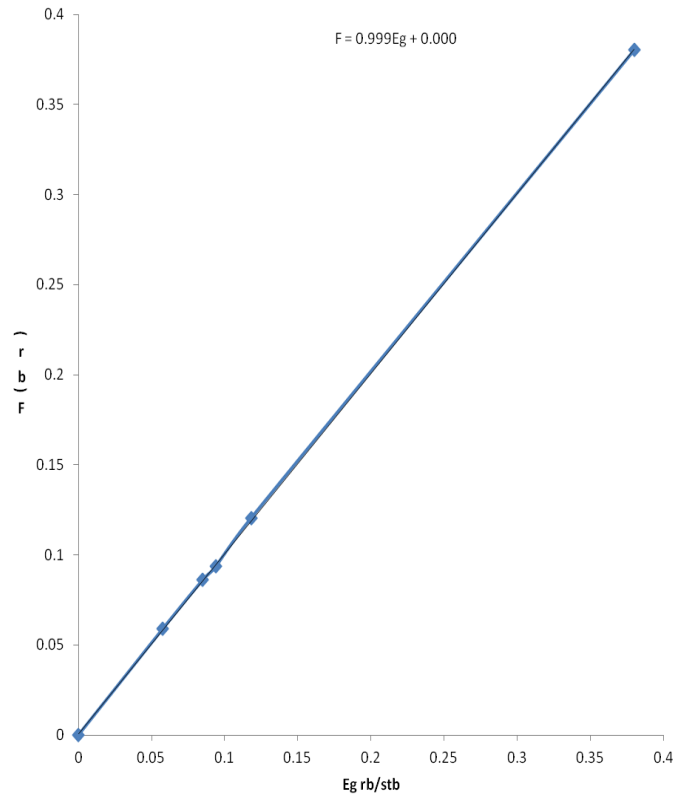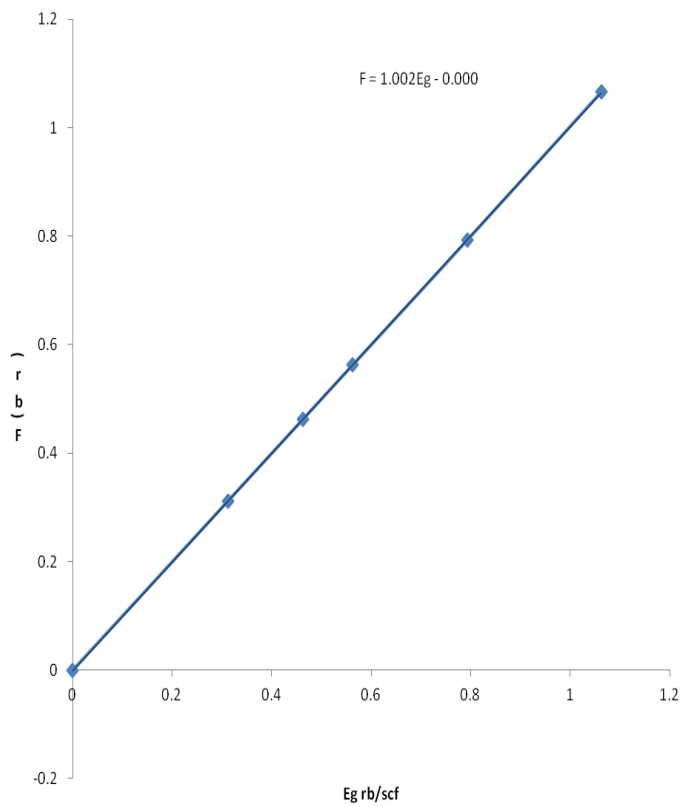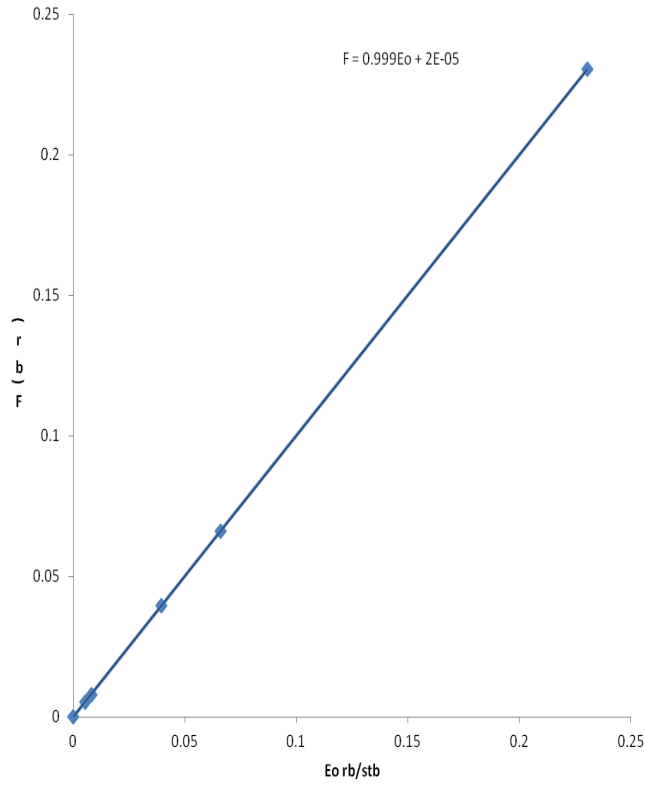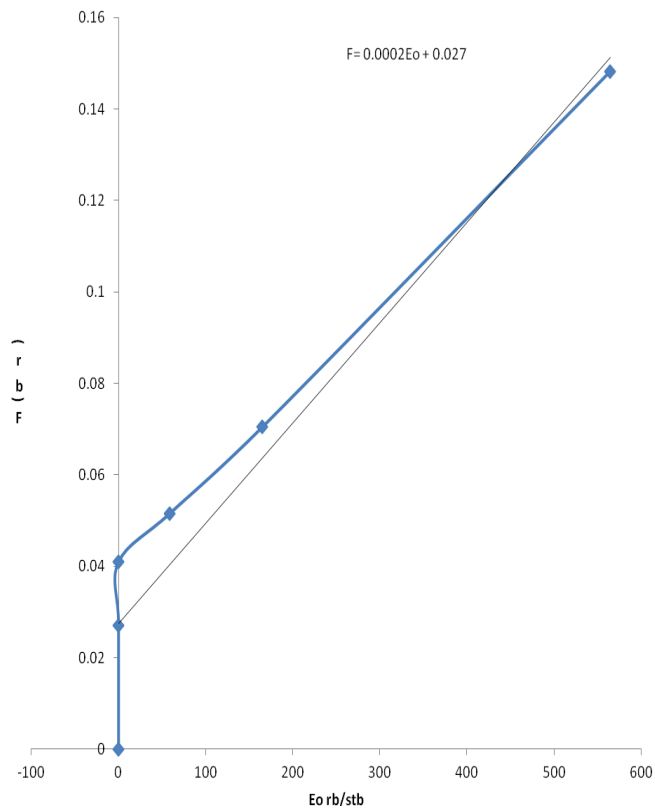**Figure 5.** Plot of F vs Eo for black oil using the CMBE.

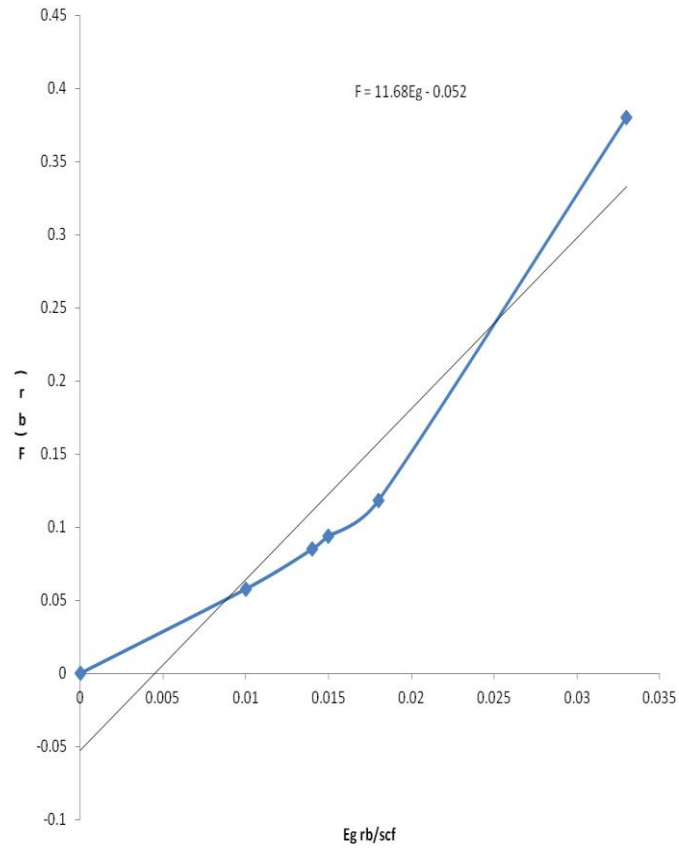**Figure 6.** Plot of F vs Eo for volatile oil using the CMBE.

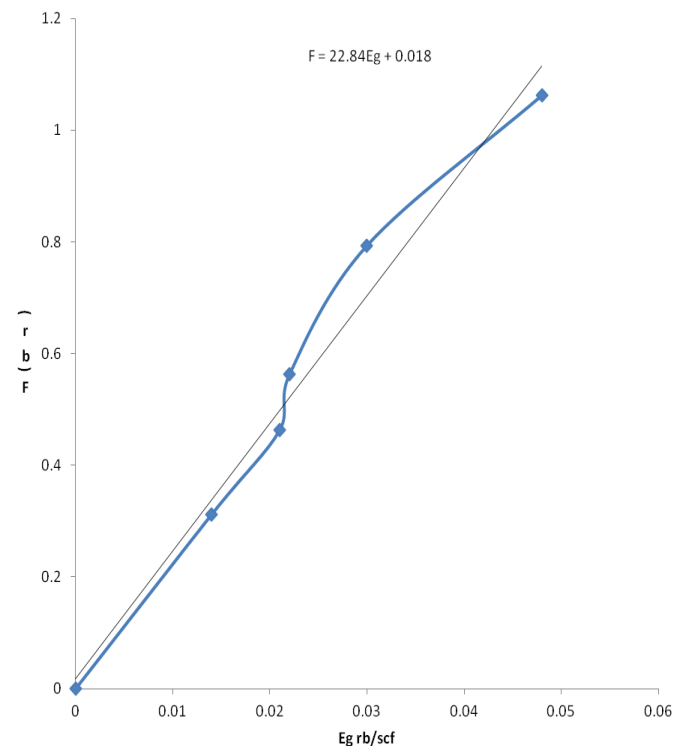**Figure 7.** Plot of F vs Eg for rich gas condensate using the CMBE.

Figure 8. Plot of F vs Eg for lean gas condensate using the CMBE.

Table 1. The volatile oil-gas ratio Rv.

Gas condensate									
A1	A2	A3	A4	A5	ρgsc	P	Ps	Psc	T
3.4584	0.04646	-0.03169875	251.08273	4.174003053	52.58	5800	5430	600	215
Pgsc	52.58								
CGR	790.59								
Rv	58108 MMstb/scf								

Volatile oil									
A1	A2	A3	A4	A5	ρosc	P	Ps	Psc	T
1.2255	0.00011	-0.194226755	240.54991	8.32137351	50.3	5000	1688	500	246
CGR	759.04								
Rv	91.583 MMstb/scf								

The slope of the lines in the plots yields the OOIP (N) estimates. Application of the GMBE yields an accurate OOIP (N) estimate for each reservoir fluid. In contrast, application of the CMBE yields an erroneous OOIP (N) estimate for all fluids except the black-oil.

In each case the CMBE under-predicts the OOIP (N) 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 Rv.

The conventional material-balance OOIP (N) 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 under-standing of the CMBE assumptions, it is perhaps clear that one should not apply the CMBE to gas-condensates. The results certainly support this conclusion. However, it is not clear as to how much fluid volatility 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.

Experience and mathematical development permits us to offer some guidelines. An inspection and comparison of Equations (2) and (3) reveals that the two material balances are equivalent if RvRps«1 and RvRs«1, where Rps, Rs, and Rv must be expressed in appropriate units to yield unit-less products. In our experience, we find that this condition is usually met if the volatile oil-gas ratio, Rv, is less than 10 stb/MMscf. Our experience agrees with the observations of Walsh (1994) (Appendices 1 and 2). 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.

The correlation proposed by El-Banbi et al. (2006), was used to determine the volatile oil-gas ratio Rv for gas condensate and volatile reservoir. The results obtained from both fluids were 58108.09 MMstb/scf for gas condensate reservoir and 91.58283 MMstb/scf for volatile

oil reservoir. Also the volatile oil-gas ratio Rv for single phase fluids which is in this work was used to calculate Rv. The results were 1011.701785 MMstb/scf for gas condensate and 1814.039736 MMstb/scf for volatile oil reservoir.

These results when compared with our critical value of Rv≤10 MMstb/scf, they are well above this criterion for the application of the CMBE for estimating reserves in these reservoirs. Preferably, the GMBE can be applied to these reservoirs, which yield more accurate results.

Conclusion

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 (1994). 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 because they fail to account for the volatile oil-gas ratio Rv. 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-conden-sates; (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.

RECOMMENDATIONS

For reservoirs containing black oil, both the CMBE and the GMBE can be applied perfectly because the value of the volatile oil-gas ratio is negligible. When carrying out reserve estimation in volatile oil and gas condensate reservoirs, it is recommended to determine the volatile oil-gas ratio Rv. The value obtained is compared with the critical value proposed by Walsh, which is helpful to make a choice between the CMBE and GMBE for application. In order to determine the volatile oil-gas ratio, use the correlation proposed by E-Banbi et al. (2006). For single phase fluid in the reservoir, to determine the value of the volatile oil-gas ratio, use the correlation proposed herein. The GMBE can be applied to all reservoir fluids without restriction but the CMBE can only be applied to the black oil and dry gas condensate reservoirs.

Conflict of Interest

The authors have not declared any conflict of interest.

REFERENCES

Amyx JW, Bass DM, Whiting RL (1960). Petroleum Reservoir Engineering Physical Properties. McGraw Hill, USA. pp.97-132.
Coats KH, Nielsen RL, Terhune MH, Weber AG (1967). 'Simulation of Three-Dimensional, Two-Phase Flow in Oil and Gas Reservoirs,' Soc. Pet. Eng. J. Trans. AIME. 240:377-88.
Cook RE, Jacoby RH, Ramesh AB (1974). 'A Beta-Type Reservoir Simulator for Approximating Compositional Effects During Gas Injection.' Soc. Pet. Eng. J. 14(5):471-81.
Craft BC, Hawkins MF Jr. (1959). Applied Petroleum Reservoir Engineering. Prentice-Hall, New Jersey. pp. 123-145.
Dake LP (1978). Fundamentals of Reservoir Engineering. Elsevier Scientific Publication Co., New York. pp. 318-334.
El-Banbi AH, Fattah KA, Sayyouh MH (2006). "New Modified Black-oil Correlation For Gas Condensate and Volatile Oil Fluids." A paper presented at SPE Annual Technical Conference and Exhibition, Texas, USA. pp. 24-27.
Havlena D, Odeh AS (1963). 'The Material Balance as an Equation of a Straight Line.' J. Pet. Tech. Trans. AIME. 228:896-900.
Muskat M (1949). Physical Principles of Oil Production. McGraw-Hill, New York.
Penuela G, Eduardo A, Carlos E, Meza NS (2001). A new material balance equation for naturally fractured reservoir using a dual system approach. SPE Western Regional Meeting, 26-30 March, Bakersfield, California. P 6883.
Pirson SJ (1958). Oil Reservoir Engineering. McGraw-Hill Book Co., New York.
Schilthuis RJ (1936). 'Active Oil and Reservoir Energy.' Trans. AIME. 148:33-52.
Stone HL, Garder AO Jr (1961). 'Analysis of Gas-Cap or Dissolved Gas Drive Reservoirs.' Soc. Pet. Eng. J. Trans. AIME. 222:92-104.
Tarek A (2005). Advanced Reservoir Engineering. Elsevier Scientific Publication Co., New York. pp. 210-221.
Walsh MP (1994). 'A Generalised Approach to Reservoir Material Balance Calculations.' J. Can. Pet. Tech. 34(1):55

APPENDICES

Appendix A

Table A1. Fluid and reservoir properties.

Fluid properties	Black-oil	Volatile-oil	Rich gas-condensate	Lean gas-condensate
Molecular weight(MW)lb/lbmole	81.18	46.69	35.52	26.07
Initial reservoir pressure, psia	2000	5000	5800	8000
Upper saturation pressure, psia	1688	4677	5430	7255
Lower saturation pressure, psia	-	-	-	26
Reservoir temperature °F	131	246	215	215
Reservoir depth, ft	6700	10000	12800	-
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/lbmole	30.68	21.92	21.7	22.17
Initial GOR, scf/stb	838.5	2909.4	6042	22527
Initial FVF, RB/stb	1.467	2.723	4.382	12.732
Stock tank oil gravity, API	38	44	36	39
Stock tankoil MW, lb/lbmole	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 Rgo, scf/stb	746.96	759.04	790.59	833.48
Composition mole fraction				
N_2	0.0028	0.0167	0.0223	0.0167
C1	0.2925	0.6051	0,6566	0.6051
CO_2	0.0020	0.0218	o.oo45	0.0218
C2	0.1044	0.0752	0.1170	0.0752
C3	0.1214	0.0474	0.0587	0.0474
i-C4	0.0057	0.0000	0.0127	0.0000
n-C4	0.0608	0.0412	0.0168	0.0412
i-C5	0.0148	0.0000	0.0071	0.0000
n-C5	0.0296	0.0297	0.0071	0.0297
C6	0.0345	0.0138	0.0098	0.0138
C7+	0.3315	0.1491	0.0872	0.1491

Table A2. Black-oil fluid properties.

P (Psia)	Bo (RB/stb)	Bg (RB/Mscf)	Rs (scf/stb)	Rv (stb/MMscf)	Eo (RB/stb)
2000	1.467	1.749	838.5	1192.6	0.0000
1800	1.472	1.755	838.5	1192.6	0.0052
1700	1.475	1.758	838.5	1192.6	0.0080
1640	1.463	1.921	816.1	0.2	0.0394
1600	1.453	1.977	798.4	0.2	0.0659
1400	1.408	2.308	713.4	0.0	0.2305

Table A3. Volatile-oil fluid properties.

P (Psia)	Bo (RB/stb)	Bg (RB/Mscf)	Rs (scf/stb)	Rv (stb/MMscf)	Eo (RB/stb)
4998	2.713	0.932	2909	343.0	0.0000
4798	2.740	0.942	2909	343.0	0.0270
4698	2.754	0.947	2909	343.0	0.0410
4658	2.707	0.830	2838	116.0	0.0517
4598	2.631	0.835	2711	111.0	0.0704
4398	2.338	0.853	2247	106.0	0.1483

Table A4. Rich gas-condensate fluid properties.

P (Psia)	Bo (RB/stb)	Bg (RB/Mscf)	Rs (scf/stb)	Rv (stb/MMscf)	Eo (RB/stb)
5800	4.382	0.725	6042	165.5	0.0000
5550	4.441	0.735	6042	165.5	0.0590
5450	4.468	0.739	6042	165.5	0.0860
5420	2.378	0.740	2795	164.2	0.0936
5300	2.366	0.743	2750	156.6	0.1204
4800	2.032	0.758	2128	114.0	0.3803

Table A5. Lean gas-condensate fluid properties.

P (Psia)	Bo (RB/stb)	Bg (RB/Mscf)	Rs (scf/stb)	Rv (stb/MMscf)	Eo (RB/stb)
8000	12.732	0.565	22527	44.4	0.0000
7500	13.044	0.579	22527	44.4	0.3120
7280	13.192	0.586	22527	44.4	0.4630
7250	1.054	0.587	860	44.3	0.5625
7000	1.041	0.595	819	43.9	0.7935
6500	1.018	0.613	754	40.3	1.0655

Table A6. Volatile oil-gas ratio correlation constants for gas condensate and volatile oil fluid.

Constant	Gas condensate	Volatile oil
A1	3.45841109	1.225537042
A2	6.89461EXP-5	0.000107257
A3	-0.03169875	-0.194226755
A4	251.0827307	240.549909
A5	4.174003053	8.32137351

Source: Adopted from El-Banbi,Fattah and Sayyouh (2006).

Table A7. Modified standing correlation parameters for Gas condensates and volatile oil fluids, used for single phase fluid volatile oil-gas ratio.

Constant	Gas condensate	Volatile oil
A1	0.19408473	47.23306
A2	-3709.4214	-8.833514
A3	1.06052098	1.3251534
A4	-0.05022324	0.0091756
A5	-0.003771627	-0.000385524

Source: Adopted from El-Banbi,Fattah and Sayyouh (2006).

Appendix B

GMBE

$$F = Np\left[\frac{Bo(1-RvRps)+(Rps-Rs)Bg}{(1-RvRs)}\right]$$ (2a)

$$Eo = \frac{(Bo-Boi)+Bg(Rsi-Rs)+Rv(BoiRs-BoRsi)}{(1-RvRs)}$$ (2b)

$$Eg = \frac{(Bg-Bgi)+Bo(Rvi-Rv)+Rs(BgiRv-BgRvi)}{(1-RvRs)}$$ (3c)

CMBE

$$F = Np[Bo + (Rps - Rs)Bg]$$ (3a)

$$Eo = Bo - Boi + Bg(Rsi - Rs)$$ (3b)

$$Eg = Bg - Bgi$$ (3c)

Applying the GMBE to the Black oil

At pressure of 2000 psi:

$$F = 0 \times \left[\frac{1.467(1-1192.6\times838.5)+(838.5-838.5)\times1.749}{(1-1192.6\times838.5)}\right] = 0.0000 \text{ RB}$$

$$Eo = \frac{(1.467-1.467)+1.749(838.5-838.5)+1192.6(1.467\times838.5-1.467\times838.5)}{(1-1192.6\times838.5)} = \frac{0}{-999,994.1} = 0.0000 \text{ B/stb}$$

At pressure of 1800psi:

$$F = 0.00353\left[\frac{1.472(1-1192.6\times838.5)+(838.5-838.5)1.755}{(1-1192.6\times838.5)}\right] = 0.00353\left[\frac{-1471991.315}{-999994.1}\right] = 0.0052 \text{ RB}$$

$$Eo = \frac{(1.472-1.467)+1.755(838.5-838.5)+1192.6(1.467\times838.5-1.472\times838.5)}{(1-1192.6\times838.5)} = \frac{-4999.9705}{-999994.1} = 0.005 \text{ RB/stb}$$

The same procedure is followed to calculate F, Eo and Eg of the various fluids using the Microsoft Excel software below:

Appendix B1. Applying GMBE to the fluids.

				Black-oil			
P	Bo	Bg	Rs	Rv	Np	Eo	F
psia	RB/stb	RB/Mscf	scf/stb	stb/MMscf	stb	RB/stb	RB
2000	1.467	1.749	838.5	1192.6	0	0	0
1800	1.472	1.755	838.5	1192.6	0.00353	0.0052	0.0052
1700	1.475	1.758	838.5	1192.6	0.00542	0.008	0.008
1640	1.463	1.921	816.1	0.2	0.02693	0.0394	0.0394
1600	1.453	1.977	798.4	0.2	0.04542	0.0659	0.066
1400	1.408	2.308	713.4	0	0.16364	0.2305	0.2304

				Volatile-oil			
P	Bo	Bg	Rs	Rv	Np	Eo	F
psia	RB/stb	RB/Mscf	scf/stb	stb/MMscf	stb	RB/stb	RB
4998	2.713	0.932	2909	343	0	0	0
4798	2.74	0.942	2909	343	0.00989	0.027	0.0271
4698	2.754	0.947	2909	343	0.01489	0.041	0.041
4658	2.707	0.83	2838	116	0.01906	0.0517	0.0516
4598	2.631	0.835	2711	111	0.0268	0.0704	0.0705
4398	2.338	0.853	2247	106	0.06339	0.1483	0.1482

				Rich gas-condensate			
P	Bo	Bg	Rs	Rv	G	F	Eg
psia	RB/stb	RB/Mscf	scf/stb	stb/MMscf	scf	RB	RB/scf
5800	4.382	0.725	6042	165.5	0	0	0
5550	4.441	0.735	6042	165.5	0.0785	0.0577	0.059
5450	4.468	0.739	6042	165.5	0.11488	0.0849	0.086
5420	2.378	0.74	2795	164.2	0.12703	0.094	0.0936
5300	2.366	0.743	2750	156.6	0.15882	0.118	0.1204
4800	2.032	0.758	2128	114	0.50145	0.3801	0.3803

				Lean gas-condensates			
P	Bo	Bg	Rs	Rv	G	F	Eg
psia	RB/stb	RB/Mscf	scf/stb	stb/MMscf	scf	RB	RB/scf
8000	12.732	0.565	22527	44.4	0	0	0
7500	13.044	0.579	22527	44.4	0.53886	0.312	0.312
7280	13.192	0.586	22527	44.4	0.7901	0.463	0.463
7250	1.054	0.587	860	44.3	0.95826	0.5625	0.5625
7000	1.041	0.595	819	43.9	1.33361	0.7935	0.7935
6500	1.018	0.613	754	40.3	1.73263	1.0621	1.0655

Applying the CMBE to the fluids

Black-oil

P	Bo	Bg	Rs	Rv	Np	Eo	F
psia	RB/stb	RB/Mscf	scf/stb	stb/MMscf	stb	RB/stb	RB
2000	1.467	1.749	838.5	1192.6	0	0	0
1800	1.472	1.755	838.5	1192.6	0.00353	0.0052	0.0052
1700	1.475	1.758	838.5	1192.6	0.00542	0.008	0.008
1640	1.463	1.921	816.1	0.2	0.02693	0.0394	0.0394
1600	1.453	1.977	798.4	0.2	0.04542	0.0659	0.066
1400	1.408	2.308	713.4	0	0.16364	0.2305	0.2304

Appendix B1. Contd.

Volatile-oil							
P	**Bo**	**Bg**	**Rs**	**Rv**	**Np**	**Eo**	**F**
psia	RB/stb	RB/Mscf	scf/stb	stb/MMscf	stb	RB/stb	RB
4998	2.713	0.932	2909	343	0	0	0
4798	2.74	0.942	2909	343	0.00989	0.027	0.0271
4698	2.754	0.947	2909	343	0.01489	0.041	0.041
4658	2.707	0.83	2838	116	0.01906	58.924	0.0516
4598	2.631	0.835	2711	111	0.0268	165.248	0.0705
4398	2.338	0.853	2247	106	0.06339	564.311	0.1482

Rich gas-condensate							
P	**Bo**	**Bg**	**Rs**	**Rv**	**G**	**Eg**	**F**
psia	RB/stb	RB/Mscf	scf/stb	stb/MMscf	scf	RB/scf	RB
5800	4.382	0.725	6042	165.5	0	0	0
5550	4.441	0.735	6042	165.5	0.078503	0.01	0.0577
5450	4.468	0.739	6042	165.5	0.114885	0.014	0.0849
5420	2.378	0.74	2795	164.2	0.127027	0.015	0.094
5300	2.366	0.743	2750	156.6	0.158816	0.018	0.118
4800	2.032	0.758	2128	114	0.501451	0.033	0.3801

Lean gas-condensate							
P	**Bo**	**Bg**	**Rs**	**Rv**	**G**	**Eg**	**F**
psia	RB/stb	RB/Mscf	scf/stb	stb/MMscf	scf	RB/scf	RB
8000	12.732	0.565	22527	44.4	0	0	0
7500	13.044	0.579	22527	44.4	0.53886	0.014	0.312
7280	13.192	0.586	22527	44.4	0.790102	0.021	0.463
7250	1.054	0.587	860	44.3	0.958262	0.022	0.5625
7000	1.041	0.595	819	43.9	1.333613	0.03	0.7935
6500	1.018	0.613	754	40.3	1.732626	0.048	1.0621