New Modified Black Oil PVT Correlations for Gas Condensate and Volatile Oil Fluids

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Abstract

Several authors have shown the applicability of modified black oil (MBO) approach for modeling gas condensate and volatile oil reservoirs. It was shown before that MBO could adequately replace compositional simulation in many applications. In this work, a new set of MBO PVT correlations was developed. The four PVT functions (oil-gas ratio, R_v, solution gas-oil ratio, R_s, oil formation volume factor, B_o, and gas formation volume factor, B_g) were investigated. According to our knowledge, no other correlation for calculating oil-gas ratio exists in the petroleum literature. Alternatively, oil-gas ratio (needed for material balance and reservoir simulation calculations of gas condensate and volatile oil reservoirs) had to be generated from a combination of laboratory experiments and elaborate calculation procedures using EOS models. In our work, we found that Whitson and Torp method for generating Modified Black Oil (MBO) PVT properties yielded best results when compared with compositional simulation. This method (and the others available in the literature such as Coats' and Walsh's) requires the use of data from PVT laboratory experiments and proper construction of EOS models. We used Whitson and Torp's method to generate our database of the MBO PVT curves used in developing our correlations after matching the PVT experimental results with an EOS model. For each one of the four PVT parameters, we used 1850 values obtained from PVT analysis of eight gas condensate fluid samples and 1180 values obtained from PVT analysis of five volatile oil fluid samples. The samples were selected to cover a wide range of fluid composition, condensate yield, reservoir temperature, and pressure. The data points were generated by extracting the PVT properties of each sample at six different separator conditions. We then used multi-variable regression techniques to calculate our correlation constants. For each fluid type, we generated two correlations for oil-gas ratio, Rv, (one requires the knowledge of saturation pressure and has slightly lower error than a correlation that does not require the knowledge of saturation pressure). For solution gas-oil ratio, Rs, new correlations were developed following the forms suggested by Vasques and Beggs and Standing correlations. For oil formation volume factor, Bo, a modified Standing correlation can be used or the original Vasques and Beggs with slightly higher error. We also found that conventional calculation of gas formation volume factor from Standing's z-factor works well with our database.

The new correlations were validated using the generalized material balance equation calculations with data generated from a compositional reservoir simulator.
These new correlations depend only on readily available parameters in the field and can have wide applications when representative fluid samples are not available.

Introduction

In 1973, Spivak and Dixon[1] introduced the Modified Black Oil (MBO) simulation approach. The MBO simulation considers three components (dry gas, oil, and water). The main difference between the conventional black-oil simulation and the MBO simulation (also called Extended Black-Oil) lies in the treatment of the liquid in the gas phase. The MBO approach assumes that stock-tank liquid component can exist in both liquid and gas phases under reservoir conditions. It also assumes that the liquid content of the gas phase can be defined as a sole function of pressure called vaporized oil-gas ratio, R_v (also referred to as r_s[2]). This function is similar to the solution gas-oil ratio, R_s, normally used to describe the amount of gas-in-solution in the liquid phase.

Whitson and Torp[3] presented a procedure to calculate MBO properties from PVT experimental data of gas condensate. Coats[2] also presented a different procedure for gas condensate fluids. Coats procedure was extended by McVay[4] for volatile oil fluids. Walsh and Towler[5] also presented a procedure to calculate MBO PVT properties from the CVD experiment data. Abdel Fattah *et al.*[6] showed that both Whitson and Torp and Coats procedures provide excellent match with compositional simulation results when PVT experimental data are matched with an EOS model and then used to output the MBO PVT properties.

El-Banbi *et al.*[7] presented a field case where they used MBO PVT properties and the MBO approach to speed us a field development plan study. They presented convincing evidence that MBO approach is adequate in simulation of gas condensate fluids above and below the dew point and with water influx. Other authors also presented different

comparisons between the MBO and compositional approaches[2,3,6]. Fevang *et al.*[8] presented guidelines to help engineers choose between MBO and compositional approaches.

In this paper, we show new correlations to develop MBO PVT properties when fluid samples are not available.

Fluid Samples

Thirteen reservoir fluid samples were used in this study [eight gas condensates, (GC), and five volatile oils, (VO)]. The samples were obtained from reservoirs representing different locations and depth, and were selected to cover a wide range of oil and gas fluid characteristics. Table 1 presents a description of the major properties of the thirteen fluid samples. The PVT experiments for all these samples were presented in Ref. 9. Some samples represent near critical fluids (VO 2, VO 5, GC 1, and GC 2) as explained by McCain and Bridges[10].

Approach

For every sample in Table 1, we constructed an EOS model that matched as best as possible the experimental results of all available PVT laboratory experiments (CCE, DL, CVD, and separator tests). For consistency, we developed all EOS models using Peng and Robinson[11] EOS with volume shift correction (3-parameter EOS). We followed the procedure suggested by Coats and Smart[12] to match the laboratory results.

We then used the developed EOS model for each sample to output MBO PVT properties at different separator conditions using Whitson and Torp[3] procedure. The MBO PVT properties include the four functions required for MBO simulation (oil-gas ratio, R_v, solution gas-oil ratio, R_s, oil formation volume factor, B_o, and gas formation volume factor, B_g). For each property of the four, we generated six curves, representing six different separator conditions, for each sample. Our database of PVT properties consisted of 1850 points from 8 different gas condensate samples and 1180 points from 5 volatile oil samples. We used PVTi program of Eclipse[13] to generate the curves for the MBO PVT properties.

For the three parameters that are commonly used for black oil material balance and simulation (R_s, B_o, and B_g), we tested some of the commonly known correlations to see which one fits our database and to see if we need to modify the correlation' constants. For the fourth parameter (R_v), we had to develop a completely new correlation, since we think that the petroleum literature lacks one. Our approach here was to start from a similar form to R_s correlations, then modify the correlation parameters using regression methods until we obtain the best fit to R_v data.

MBO PVT Correlations

The following discussion shows which correlations were used for each PVT parameter of the four required for MBO material balance and simulation calculations. We also report the average error which we calculated using Eq. 1.

$$error = \frac{1}{N}\sum_{i=1}^{N}\left|\frac{Data - Model}{Data}\right| \quad \text{.....(1)}$$

Solution Gas Oil Ratio, R_s. Several correlations were used to test the data base for both volatile oil and gas condensate samples. We found that the form suggested by Vasques and Beggs[14] gave the best results after modifying the correlation constants. The modified Vasques and Beggs correlation has the form given in Eq. 2 with the constants in Table 2 for gas condensates and volatile oils.

$$R_S = A1 \times \gamma_{gsc} \times p^{A2} \times EXP\left[\frac{A3 \times API}{T_r}\right] \quad \text{.....(2)}$$

The average error calculated using Eq. 1 for gas condensate was 19.3% with standard deviation of 0.065. The average error for volatile oil was 24.8% with standard deviation of 0.24. For volatile oil above the bubble point, R_s, value is taken as the same of the bubble point value.

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 to 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 following form was suggested and it gives 10.2% average error and 0.0308 standard deviation for gas condensates and 27.8% average error and 0.1271 standard deviation for volatile oils.

$$R_v = \frac{A1 \times \rho_{gsc} \times (A2 \times p^2 + A3 \times p + A4)}{p_s} \times EXP\left[\frac{A5 \times CGR \times T_{sc}}{\rho_{osc} \times T_r \times P_{sc}}\right] \quad \text{.....(3)}$$

The correlation constants ($A1$ through $A5$) are shown in Table 3. Fig. 1 is a cross plot for all gas condensate points and shows the 45 degrees line, as an indication of the goodness of fit or calculated results with the experimental results.

Oil Formation Volume Factor, B_o. Several correlations were tested against the database of B_o points for both the gas condensate and volatile oil samples below the saturation pressure. It was found that both Standing correlation and Vasques and Beggs correlation can be used adequately (error slightly higher than 5%) without modifications. However, the error percentage can be improved for B_o if we use the form suggested by Standing with the constants presented in Table 4. The modified Standing correlation is given as Eq. 4.

$$B_O = A1 + A2 * \left(R_S \sqrt{\frac{\gamma_{gsc}}{\gamma_{osc}}} + A3 * (T_r - 460)\right)^{A4} \quad \text{.....(4)}$$

The above form gives average absolute error of 2.82% and standard deviation of 0.0302 for gas condensate samples, and error of 1.67% and standard deviation of 0.0005 for volatile oils.

Gas Formation Volume Factor, B_g. Gas formation volume factor can be calculated from z factor. We tested the use of Sutton[14] correlation to calculate critical properties then used Standing z-factor correlation using the calculation procedure suggested by Dranchuk and Abou-Kassem[15]. We found this procedure for calculating Bg is adequate for both the gas condensate and volatile oil samples. The average absolute error for gas condensates was 8.36% with standard deviation of 0.0089 and 5.96% with standard deviation of 0.0049 for volatile oils.

Validation of MBO PVT Correlations

In addition to cross-plots (e.g. Fig. 1) to see how the new correlation values compared to the values obtained from the EOS model, we also used both reservoir simulation and material balance calculations to validate the new correlations.

We used the generalized material balance equation suggested by Walsh[15,16] to validate the new correlations by performing the material balance calculations using the PVT properties from the new correlations to calculate original hydrocarbon in place. These values were compared to original hydrocarbon in place values obtained from compositional reservoir simulation for a tank model. For simplicity, the original fluid in place was normalized to 1.0 BSTB for oil cases and 1 Bscf for gas cases. **Fig. 2** shows a plot of F versus the expansion term, Eg, for a gas condensate sample (GC 1), as suggested by Walsh procedure. The slope of the line passing through the calculated points gives the original fluid in place volume. The plot shows that the slope of the line is 1.038, i.e. the error in gas in place calculation is approximately 1.4%.

Fig. 3 is a similar plot for a volatile oil sample (VO 1). The plot shows a line slope of 0.9948 which is equivalent to error in the oil in place calculation of approximately 0.5%. We calculated the error in fluid in place calculations for most of the fluid samples in our database and reported the error percentages in Table 5.

Discussion

The petroleum literature has reported many cases where MBO approach was used to replace the more expensive compositional simulation. To generate MBO PVT properties, one has to have a representative fluid sample that undergone enough laboratory experiments. Then, one usually constructs EOS models to match the laboratory experimental results. Then, one can output the MBO properties at appropriate separator conditions using one of the procedures suggested in the literature. This process requires the availability of a representative fluid sample in addition to the skills of EOS modeling.

The set of correlations presented in this work can be used to generate MBO PVT properties without the need for fluid samples or elaborate procedure for EOS calculations. The application of these correlations is of particular importance especially when a representative sample is not available.

Conclusions

1. New correlations are presented for oil-gas ratio of gas condensates and volatile oils. The correlation can be used in generalized material balance calculations and MBO simulation. The new correlations match the fluid properties of the database selected for computations. They were also validated using generalized material balance calculations.
2. Existing solution gas oil ratio and oil formation volume factor correlations were modified to increase their accuracy when used with gas condensates and volatile oils.
3. Gas formation volume factor computation from compressibility factor calculated using Dranchuk and Abou-Kassem was found to be adequate for gas condensates and volatile oils used in our database.

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Nomenclature

B_g = Gas formation volume factor, bbl/SCF
B_o = Oil formation volume factor, bbl/STB
CCE = Constant Composition Experiment
CVD= Constant Volume Depletion Test
DL = Differential Liberation Test
EOS = Equation of state
MBO= Modified Black Oil
PVT = Pressure-Volume-Temperature
R_s = Initial solution gas oil-ratio, SCF/STB
R_v = Volatile oil-gas ratio, STB/Mcf

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TABLE 1 - CHARACTERISTICS OF FLUID SAMPLES

Property	VO 1	VO 2	VO 3	VO 4	VO 5	GC 1	GC 2	GC 3	GC 4	GC 5	GC 6	GC 7	GC 8
Reservoir Temperature (°F)	249	246	260	190	197	312	286	238	256	186	312	300	233
Initial Reservoir Pressure (psig)	NA	5055	5270	NA	13668	14216	NA	6000	7000	5728	14216	5985	17335
Initial Producing Gas-Oil ratio (SCF/STB)	1991	2000	2032	2424	2416	3413	4278	NA	4697	5987	8280	6500	6665
Stock Oil gravity (° API)	45.5	51.2	NA	36.8	34.1	45.6	NA	NA	46.5	58.5	50.7	45.6	43
Saturation Pressure (psig)	4527	4821	4987	7437	9074	5210	5410	4815	6010	4000	5465	5800	11475
Components	**Composition (Mole %)**												
CO_2	2.14	2.18	2.4	0.1	0.34	2.66	4.48	0.14	0.01	0.18	2.79	6.98	0.36
N_2	0.11	1.67	0.31	0.16	0	0.17	0.70	1.62	0.11	0.13	0.14	1.07	0.31
C_1	55.59	60.51	56.94	69.84	72.47	59.96	66.24	63.06	68.93	61.72	66.73	65.25	81.23
C_2	8.7	7.52	9.21	5.37	4.57	7.72	7.21	11.35	8.63	14.1	10.22	8.92	5.54
C_3	5.89	4.74	5.84	3.22	2.79	6.50	4.00	6.01	5.34	8.37	5.90	4.81	2.66
iC_4	1.36	4.12	1.44	0.87	0.67	1.93	0.84	1.37	1.15	0.98	1.88	0.85	0.62
nC_4	2.69	0	2.73	1.7	1.33	3.00	1.76	1.94	2.33	3.45	2.10	1.75	1.06
iC_5	1.17	2.97	1.03	0.79	0.69	1.64	0.74	0.84	0.93	0.91	1.37	0.65	0.47
nC_5	1.36	0	1.22	0.88	0.82	1.35	0.87	0.97	0.85	1.52	0.83	0.69	0.52
C_6	1.97	1.38	1.96	1.41	1.52	2.38	0.96	1.02	1.73	1.79	1.56	0.83	0.84
C_{7+}	19.02	14.91	16.92	15.66	14.8	12.69	12.2	11.68	9.99	6.85	6.48	8.2	6.39

TABLE 2 – Modified Vasques and Beggs Correlation Parameters for Gas Condensates and Volatile Oil Fluids (Eq. 2).

Constant	Gas Condensate	Volatile Oil
A1	11.96254887	0.000747028
A2	1.409159532	1.579778903
A3	-113.052865	19.40360272
A4	1.17838573	1.198775033

TABLE 3 – Oil-Gas Ratio Correlation Constants for Gas Condensates and Volatile Oil Fluids (Eq. 3).

Constant	Gas Condensate	Volatile Oil
A1	٣,٢٤٠٢٥٦	٠,٤٧٥٣٤
A2	٦,٩٣٢٥٤E-05	٠,٠٠٠١٦
A3	- 0.033132	- ٠,٣٢٦٩٣
A4	٢٣٠,١٨٠١٤	٢٢٦,٠٨٧٨
A5	٤,٤٦٦٤٨	١٢,٧٩٥١

TABLE 4 – Oil Formation Volume Factor Correlation Constants for Gas Condensates and Volatile Oil Fluids (Eq. 4).

Constant	Gas Condensate	Volatile Oil
A1	1.021769759	0.885751417
A2	0.000115754	9.85924E-05
A3	1.536601662	2.579717995

TABLE 5 – Error in Fluid In Place Calculation from Generalized Material Balance Calculations Using the New Correlations.

Fluid Sample	Original Fluid In Place	Error (%)
VO 1	0.9948	0.52
VO 2	1.0027	0.27
GC 1	1.0138	1.38
GC 2	0.9451	5.49
GC 3	1.0154	1.54
GC 4	1.0092	0.92
GC 5	1.1526	15.26
GC 6	1.0319	3.19

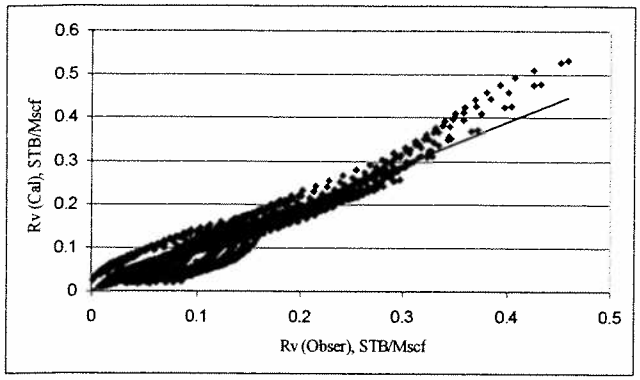

Fig. 1 - Cross-plot for R_V (New Correlation) vs. R_V (Driven from the EOS Model) for gas Condensate samples.

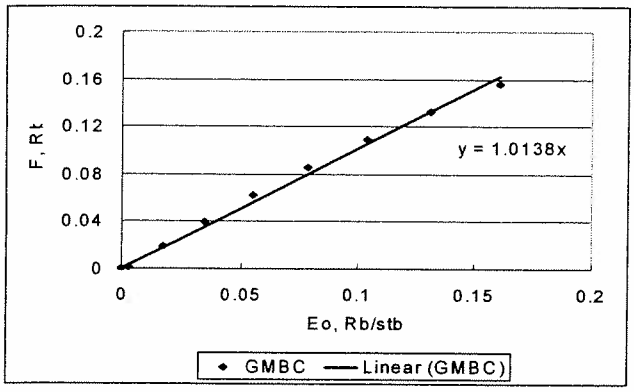

Fig. 2 – Material Balance as Straight Line Calculations for a Gas Condensate Sample (GC 1).

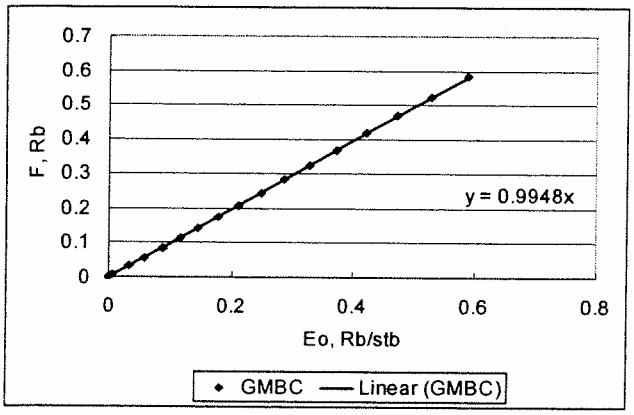

Fig. 3 – Material Balance as Straight Line Calculations for a Volatile Oil Sample (VO 1).