Chapter 7 Black-Oil PVT Formulations

7.1 Introduction

This chapter reviews black-oil pressure/volume/temperature (PVT) formulations, gives examples of their application, and provides guidelines for choosing the proper PVT formulation for a given reservoir. Sec. 7.2 reviews the traditional black-oil PVT formulation. The three basic PVT properties are introduced: solution gas/oil ratio, R_s ; oil formation volume factor (FVF), B_o ; and gas FVF, B_g . These properties define the PVT behavior of reservoir-oil and -gas mixtures by quantifying the volumetric behavior and the distribution of surface-gas and surface-oil "components" as functions of pressure.

Many reservoirs being discovered today are at great depths, with a higher percentage of these deep reservoirs containing gas-condensate and volatile-oil fluids. Treatment of these reservoirs requires modification of the standard PVT formulation, as Sec. 7.3 discusses. In particular, the additional property solution oil/gas ratio, r_s , is introduced, together with a modified gas FVF.

Sec. 7.4 covers the application of black-oil PVT properties to well-rate deliverability and material-balance calculations. Sec. 7.5 discusses alternative black-oil PVT formulations, including the partial-density approach. And finally, Sec. 7.6 briefly reviews some limited compositional formulations that are used in the simulation of gas-injection processes.

7.2 Traditional Black-Oil Formulation

It was already clear in the 1920's that the engineering of oil reservoirs required knowledge of how much gas was dissolved in the oil at reservoir conditions and how much the oil would shrink when it was brought to the surface. It was also recognized that free gas at reservoir conditions would expand up to several hundred times when brought to surface conditions. Engineering quantities were needed to relate surface volumes to reservoir volumes and vice versa. Three properties evolved to serve this purpose: solution gas/oil ratio, R_s ; oil FVF, B_o ; and gas FVF, B_g . These properties are defined, respectively, by

These three properties constitute the traditional black-oil PVT formulation, which has the following assumptions.

1. Reservoir oil consists of two surface "components," stock-tank oil and surface (total separator) gas.

Reservoir gas does not yield liquids when brought to the surface.
 Surface gas released from the reservoir oil has the same properties as the reservoir gas.

4. Properties of stock-tank oil and surface gas do not change during depletion of a reservoir.

Fig. 7.1¹ illustrates schematically the relation between reservoir phases and surface components. This simplified PVT formulation is still the standard for most petroleum engineering applications. The traditional black-oil quantities, R_s , B_o , and B_g , can be estimated with the correlations in Chap. 3 or can be calculated from differential-liberation and multistage-separator data (Chap. 6).

The validity of the traditional black-oil PVT formulation depends primarily on the reservoir-oil volatility. Any reservoir oil with less than \approx 750 scf/STB initial solution gas/oil ratio can probably be treated with the traditional PVT formulation. Also, any oil reservoir that produces at higher than its bubblepoint pressure during most of the reservoir's productive life can be treated with this formulation (e.g., strong waterdrive, gas-cap-drive, or waterflooded reservoirs).

Volatile oils usually have an initial gas/oil ratio (GOR) greater than $\approx 1,000$ scf/STB and an initial stock-tank-oil gravity > 35°API. The following are the two main depletion characteristics of a volatile-oil reservoir: (1) varying surface gravity of produced stock-tank oil and (2) the percentage of produced stock-tank oil coming from the flowing reservoir gas increases from zero initially to a significant percentage at depletion (potentially >90%).

For most petroleum engineering calculations, the variation in stock-tank-oil gravity can be neglected. However, neglecting the surface oil that is produced from flowing reservoir gas may cause gross underestimation of the ultimate stock-tank-oil recovery. Fig. **7.2** shows the actual depletion characteristics of a volatile-oil reservoir, where reservoir pressure decreases from 5,000 to 1,800 psia, produced surface-oil gravity increases from 44 to 62°API, and producing GOR increases from 3,800 to 22,000 scf/STB.

A good check of the traditional black-oil formulation is to compare reservoir material-balance performance determined on the basis of standard black-oil PVT properties (e.g., a material bal-



Fig. 7.1—Schematic of traditional black-oil formulation relating reservoir phases to surface components.

ance²) with depletion characteristics calculated from a compositional material balance. The traditional black-oil formulation should not be used if the stock-tank-oil recoveries differ significantly (see **Figs. 7.3 and 7.4**).

Fig. 7.5 is another plot that indicates the relative volatility of an oil. Differential-liberation relative oil volumes are plotted as shrinkage $(1 - B_{od}/B_{odb})$ vs. normalized pressure (p/p_b) , which indicates whether the shrinkage is rapid or slow. A curve that drops rapidly indicates a highly volatile oil. A "black" oil will tend to plot above the solid "unit-slope" line shown in Fig. 7.5.

7.3 Modified Black-Oil (MBO) Formulation

Several modifications of the traditional black-oil formulation have been introduced to account for the surface-liquid content in reservoir gases. Most formulations introduce an additional PVT property, the solution oil/gas ratio, r_s , and a modified definition of the gas FVF. **Fig. 7.6** shows schematically the relation between reservoir phases and surface components in the MBO formulation.

Because this chapter gives a detailed description of the MBO PVT formulation, we have introduced a more concise nomenclature that distinguishes between reservoir and surface phases. Traditionally, we use the subscript o to represent both reservoir oil and stocktank oil and g to represent both reservoir gas and surface separator



Fig. 7.3—Average reservoir pressure and producing GOR vs. cumulative oil for near-critical oil Reservoir NS-2; comparison of traditional and MBO formulations.



Fig. 7.2—Depletion characteristics of a volatile-oil reservoir (adapted from Ref. 1).



Fig. 7.4—GOR's vs. pressure for near-critical Reservoir NS-2 and volatile-oil Reservoir NS-3.



Fig. 7.5—Oil shrinkage plot used to evaluate volatility of a reservoir oil (from Ref. 3).

gas. In this chapter, we use the following subscripts to distinguish between reservoir and surface phases: o = reservoir-oil phase at pand T, g = reservoir gas phase at p and T, $\overline{o}o =$ stock-tank oil from reservoir oil, $\overline{g}o =$ surface gas from reservoir oil ("solution" gas), $\overline{\sigma}g =$ stock-tank oil (condensate) from reservoir gas, $\overline{g}g =$ surface gas from reservoir gas, $\overline{o} =$ total stock-tank oil, and $\overline{g} =$ total surface gas, where the overbar indicates a surface-phase (component). To avoid confusion, the standard term γ_w is used to represent the wellstream gravity of a reservoir gas (instead of γ_g).

The four MBO PVT parameters, oil FVF, solution gas/oil ratio, dry-gas FVF, and solution oil/gas ratio are defined respectively as

$$B_o = \frac{V_o}{V_{\bar{o}o}}, \qquad (7.2a)$$

$$R_s = \frac{V_{\overline{g}o}}{V_{\overline{o}o}}, \qquad (7.2b)$$

$$B_{gd} = \frac{V_g}{V_{\overline{gg}}}, \quad \dots \quad \dots \quad \dots \quad \dots \quad (7.2c)$$



Fig. 7.7—Schematic of the Whitson-Torp⁴ method for calculating MBO properties on the basis of depletion experiments and multistage separation.



Fig. 7.6—Schematic showing relation between reservoir phases and surface phases (components) for MBO formulation.

where V_o = reservoir-oil volume, $V_{\overline{o}o}$ = volume of stock-tank oil produced from the reservoir oil, $V_{\overline{g}o}$ = volume of surface gas produced from the reservoir oil, V_g = reservoir gas volume, $V_{\overline{g}g}$ = volume of surface gas produced from the reservoir gas, and $V_{\overline{o}g}$ = stock-tank oil (condensate) produced from the reservoir gas.

Fig. 7.7 outlines one procedure for determining MBO properties. The equilibrium-gas and -oil phases from a depletion experiment [constant composition expansion, constant volume depletion (CVD), or differential liberation] are passed separately through a multistage separator. The MBO properties are calculated according to the definitions given in Eq. 7.2. **Figs. 7.8 through 7.11** show MBO properties calculated with the Whitson-Torp⁴ method for the gas condensate, near-critical oil, and volatile oils in **Table 7.1**. Refs. 5 through 11 provide alternative methods.

7.3.1 Surface Gravities. When a well produces both reservoir oil and gas, the composite surface gravities, $\gamma_{\overline{o}}$ and $\gamma_{\overline{g}}$, will be an average of the surface gravities of the two reservoir phases, $\gamma_{\overline{o}a}$ and $\gamma_{\overline{g}o}$ for the reservoir oil and $\gamma_{\overline{o}g}$ and $\gamma_{\overline{g}g}$ for the reservoir gas. The average gas gravity is given by



Fig. 7.8—Solution GOR, R_s , vs. pressure for volatile reservoir Fluids NS-1, NS-2, and NS-3 calculated with the Whitson-Torp⁴ method.





where $F_{\overline{gg}}$ = fraction of total surface gas produced from the reservoir gas.

$$F_{\overline{g}g} = \frac{V_{\overline{g}g}}{V_{\overline{g}g} + V_{\overline{g}o}} = \frac{V_{\overline{g}g}}{V_{\overline{g}}} = \frac{1 - R_s/R_p}{1 - R_s r_s}.$$
 (7.4)

The average stock-tank-oil gravity is given by

$$\gamma_{\overline{o}} = F_{\overline{o}o}\gamma_{\overline{o}o} + (1 - F_{\overline{o}o})\gamma_{\overline{o}g} , \quad \dots \quad \dots \quad (7.5)$$

where $F_{\overline{oo}}$ = fraction of total stock-tank oil that comes from the reservoir oil.

$$F_{\overline{o}o} = \frac{V_{\overline{o}o}}{V_{\overline{o}o} + V_{\overline{o}g}} = \frac{V_{\overline{o}o}}{V_{\overline{o}}} = \frac{1 - r_s R_p}{1 - R_s r_s}, \quad \dots \dots \dots \dots \dots (7.6)$$

with R_p and R_s in scf/STB and r_s in STB/scf in Eqs. 7.4 and 7.6.

Surface gravities $\gamma_{\overline{o}o}$, $\gamma_{\overline{o}g}$, $\gamma_{\overline{g}o}$, and $\gamma_{\overline{g}g}$ are determined separately for the reservoir-oil and reservoir-gas phases from multistage-separator calculations. Because the compositions of reservoir oil and gas change during pressure depletion, the surface gravities also vary with pressure. The variation in $\gamma_{\overline{o}g}$ and $\gamma_{\overline{g}o}$ in **Figs. 7.12 and 7.13** is typical of volatile-oil and gas-condensate mixtures. On the other hand, $\gamma_{\overline{o}o}$ and $\gamma_{\overline{v}g}$ usually do not vary significantly with pressure.

Although the variation in surface gravities should be considered in engineering calculations, most MBO formulations assume that

$$\gamma_{\overline{o}o} = \gamma_{\overline{o}g} = \gamma_{\overline{o}} = \text{constant}$$

and
$$\gamma_{\overline{g}o} = \gamma_{\overline{g}g} = \gamma_{\overline{g}} = \text{constant.}$$
 (7.7)



Fig. 7.10—Solution OGR, r_s , vs. pressure for volatile reservoir Fluids NS-1 and NS-3 calculated with the Whitson-Torp⁴ method.

Clearly, the assumption that $\gamma_{\overline{o}o} = \gamma_{\overline{o}g} = \gamma_{\overline{o}}$ makes predicting the variation in overall stock-tank-oil gravity during depletion impossible. As Fig. 7.2 shows, this variation can be significant.





TABLE 7.1—SOLUTION OIL/GAS RATIO CALCULATED FROM FIELD STOCK-TANK-OIL GRAVITY COMPARED WITH EOS-CALCULATED VALUES								
		r _s (STB/MMscf)						
Test Date	p _R (psia)	R _p (scf/STB)	R _s (scf/STB)	γ _ō	${\mathop{\rm EOS}\limits_{\gamma_{\overline{o}o}}}$	$\mathrm{EOS}_{\gamma_{\overline{o}g}}$	From $\gamma_{\overline{o}}$	EOS
Bubblepoint	5,555	1,500	1,500	0.8430	0.843	0.7595		100
January 1979	4,455	2,215	1,006	0.8353	0.843	0.7467	62	61
June 1980	3,685	3,840	768	0.8289	0.843	0.7401	43	44
November 1983	3,105	7,480	615	0.8189	0.843	0.7356	32	34
May 1987	2,683	9,480	514	0.8146	0.843	0.7325	28	29
Note: Whitson-Torp ⁴ method used to calculate $R_{s'} \gamma_{\overline{o}o'} \gamma_{\overline{o}g'}$ and r_s in last column. $\gamma_{\overline{o}o}$ does not change appreciably with pressure and is therefore assumed constant.								



Fig. 7.12—Surface-gas gravities vs. pressure during depletion.

Because the constant-gravity assumption is widely used, it should be considered when determining the MBO properties R_s , B_o , B_{gd} , and r_s . For example, Coats⁸ gives a procedure for determining MBO properties of a gas condensate where the original mixture is first passed through a separator to determine the surface gravities; these gravities are assumed to be constant. A depletion experiment is then simulated with an equation of state (EOS), and the equilibrium gas from each depletion stage is passed through a separator to determine r_s at the particular pressure. With constant surface gravities and r_s as a function of pressure, B_{gd} , B_o , and R_s , are determined so that reservoir-oil and -gas densities and the oil relative volumes from the depletion experiment are honored.

Surface-oil and -gas gravities are used in reservoir simulators to convert B_o , R_s , B_{ed} , and r_s to reservoir-oil and -gas densities.

$$\rho_o = \frac{62.4\gamma_{\overline{o}o} + 0.0136\gamma_{\overline{g}o}R_s}{B_o}$$

and
$$\rho_g = \frac{0.0764\gamma_{\overline{g}g} + 350\gamma_{\overline{o}g}r_s}{R_s}.$$
 (7.8)

Accurate phase densities can be important for reservoir processes where gravity affects the recovery mechanism (e.g., gravity drainage in naturally fractured reservoirs). Therefore, manual checking of MBO properties and surface gravities used as input for reservoir simulation is recommended to ensure that the reservoir-oil and -gas densities are calculated accurately.

7.3.2 Gas FVF. The traditional definition of gas FVF assumes that the number of moles of gas at the surface equals the number of moles of gas at reservoir conditions. This obviously is not correct if the reservoir gas yields condensate at the surface. The definition is still used, however, for liquid-yielding reservoir gases and is called the "wet"-gas FVF, B_{gw} . The surface volume is a hypothetical wet-gas volume consisting of the "dry"-surface-gas volume and the surface condensate converted to an equivalent surface-gas volume.

$$B_{gw} = \frac{V_g}{V_{gw}}.$$
 (7.9)

With $V_g = n_g ZRT/p$ and $V_{gw} = n_g RT_{sc}/p_{sc}$, B_{gw} is simply given by the traditional equation for gas FVF.

$$B_{gw} = \frac{p_{sc}}{T_{sc}} \frac{ZT}{P} = 0.02827 \frac{ZT}{P}, \qquad (7.10)$$

where B_{gw} is in ft³/scf, T is in °R, and p is in psia.



Fig. 7.13—Surface-oil gravities vs. pressure during depletion.

A dry-gas FVF, B_{gd} (defined as the volume of reservoir gas divided by the volume of surface gas resulting after separation of the reservoir gas), is used for the MBO formulation.

$$B_{gd} = \frac{V_g}{V_{\overline{gg}}}.$$
 (7.11)

With $V_g = n_g ZRT/p$ and $V_{\overline{g}g} = n_{\overline{g}g} RT_{sc}/p_{sc}$, the dry-gas FVF can be written

$$B_{gd} = \frac{p_{sc}}{T_{sc}} \frac{ZT}{P} (1 + C_{\bar{o}g} r_s) = 0.02827 \frac{ZT}{P} (1 + C_{\bar{o}g} r_s)$$

= $B_{gw} (1 + C_{\bar{o}g} r_s), \qquad (7.12)$

where r_s is in STB/scf, B_{gd} and B_{gw} are in ft³/scf, T is in °R, and p is in psia. $C_{\overline{og}}$ is a conversion from surface-oil volume in STB to an "equivalent" surface gas in scf.

$$C_{\bar{\sigma}g} = 379 \left(\frac{\text{scf}}{\text{lbm mol}} \right) \times 5.615 \left(\frac{\text{ft}^3}{\text{STB}} \right) \times 62.4 \frac{\gamma_{\bar{\sigma}g}}{M_{\bar{\sigma}g}} \left(\frac{\text{lbm mol}}{\text{ft}^3} \right)$$
$$= 133,000 \frac{\gamma_{\bar{\sigma}g}}{M_{\bar{\sigma}g}} \left(\frac{\text{scf}}{\text{STB}} \right). \qquad (7.13)$$

If condensate molecular weight, $M_{\overline{o}g}$, is not measured, it can be estimated with the Cragoe¹² correlation,

$$M_{\bar{\sigma}} = \frac{6,084}{\gamma_{\rm API} - 5.9}.$$
 (7.14)

The term $(1 + C_{\bar{o}g}r_s)^{-1}$ represents the mole fraction of reservoir gas that becomes dry surface gas after separation and usually ranges from 0.85 for rich gases to 1.0 for dry gases. **Fig. 7.14** shows the behavior of the ratio as a function of pressure during depletion of a gas condensate and a volatile oil.

7.3.3 Solution Oil/Gas Ratio. The following simplified relation can be used to calculate r_s in terms of reservoir-gas specific gravity, γ_w .

$$r_s = \frac{\gamma_w - \gamma_{\overline{g}g}}{4,600\gamma_{\overline{o}g} - C_{\overline{o}g}\gamma_w}.$$
 (7.15)

 γ_w is reported as a function of pressure in the differential-liberation experiment and is readily calculated from reported compositions in a CVD experiment. Assuming that $\gamma_{\overline{gg}} = \gamma_{\overline{g}}$ and $\gamma_{\overline{og}} = \gamma_{\overline{o}}$, surface gravities usually are taken from a multistage separation of the original reservoir mixture and assumed constant throughout depletion.

On the basis of field production data, r_s can be calculated in terms of the actual measured stock-tank-oil gravity, $\gamma_{\overline{q}}$.



Fig. 7.14—Fraction of reservoir gas that becomes "dry" surface gas vs. pressure during depletion of a gas condensate and a volatile oil.

$$r_s = \frac{\gamma_{\overline{o}} - \gamma_{\overline{o}o}}{R_s(\gamma_{\overline{o}} - \gamma_{\overline{o}g}) - R_p(\gamma_{\overline{o}o} - \gamma_{\overline{o}g})}.$$
 (7.16)

Table 7.1 compares r_s values from this relation (determined with field data from a volatile-oil reservoir) with r_s from EOS calculations.

7.3.4 Compositional Information. Engineering calculations based on black-oil properties actually contain more compositional information than is commonly used. Given the compositions of stock-tank oil and separator gases, we can calculate oil and gas compositions (and *K* values) at reservoir conditions using black-oil PVT properties. Also, wellstream composition can be calculated from the producing GOR.

To develop the compositional relations, we use a basis of $V_{\overline{o}}$ stock-tank barrels of total stock-tank oil. Volume of reservoir-oil and -gas phases, respectively, is

$$V_o = 5.615 \ V_{\overline{o}} F_{\overline{o}o} B_o$$

and $V_g = V_o B_{gd} (R_p - R_s F_{\overline{o}o}), \qquad (7.17)$

with V_o and V_g in ft³, R_p and R_s in scf/STB, B_o in bbl/STB, and B_{gd} in ft³/scf. $F_{\overline{o}o}$ is the fraction of total stock-tank oil that comes from the reservoir oil (Eq. 7.4).

Mass of reservoir-oil and -gas phases, respectively, in lbm is

 $m_o = m_{\overline{o}o} + m_{\overline{g}o}$

and
$$m_g = m_{\bar{o}g} + m_{\bar{g}g}$$
, (7.18)

where $m_{\overline{o}o} = 350 V_{\overline{o}} F_{\overline{o}o} \gamma_{\overline{o}o}$,

$$m_{\overline{g}o} = 0.076 V_{\overline{o}} F_{\overline{o}o} R_s \gamma_{\overline{g}o},$$

$$m_{\overline{o}g} = 350 V_{\overline{o}} (R_p - R_s F_{\overline{o}o}) \gamma_{\overline{o}g},$$

and $m_{\overline{g}g} = 0.076 V_{\overline{o}} (R_p - R_s F_{\overline{o}o}) \gamma_{\overline{g}g}$. (7.19)

This yields

$$m_o = V_{\overline{o}} F_{\overline{o}o} (350\gamma_{\overline{o}o} + 0.076R_s\gamma_{\overline{g}o})$$

and $m_g = V_{\overline{o}}(R_p - R_s F_{\overline{o}o})(350\gamma_{\overline{o}g}r_s + 0.076\gamma_{\overline{g}g})$. (7.20)

Moles of reservoir oil and gas, respectively, in lbm mol are

 $n_o = n_{\overline{o}o} + n_{\overline{g}o}$

and
$$n_g = n_{\overline{o}g} + n_{\overline{g}g}$$
, (7.21)

where
$$n_{\overline{o}o} = \frac{V_{\overline{o}}F_{\overline{o}o}C_{\overline{o}o}}{379}$$
,
 $n_{\overline{g}o} = \frac{V_{\overline{o}}F_{\overline{o}o}R_s}{379}$,
 $n_{\overline{o}g} = \frac{V_{\overline{o}}\left(R_p - R_sF_{\overline{o}o}\right)r_sC_{\overline{o}g}}{379}$,
and $n_{\overline{g}g} = \frac{V_{\overline{o}}\left(R_p - R_sF_{\overline{o}o}\right)}{379}$. (7.22)

This yields

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with $C_{\overline{o}o}$ and $C_{\overline{o}g}$ given by

$$C_{\overline{o}o} = 133,000 \frac{\gamma_{\overline{o}o}}{M_{\overline{o}o}}$$

and $C_{\overline{o}g} = 133,000 \frac{\gamma_{\overline{o}g}}{M_{\overline{o}g}}$. (7.24)

On the basis of these relations, the mole fractions of surface components in the reservoir oil are

and the mole fractions of surface components in the reservoir gas are

with K values $K_{\overline{o}} = y_{\overline{o}}/x_{\overline{o}}$ and $K_{\overline{g}} = y_{\overline{g}}/x_{\overline{g}}$. Strictly speaking, Components \overline{o} and \overline{g} are not the same "species" and K values cannot be interpreted physically unless (1) the properties of surface oils from reservoir gas and oil are equal and constant and (2) the surface gases from reservoir gas and oil are equal and constant.

The mole fraction of the wellstream that comes from the reservoir gas is $F_g = n_g/(n_g + n_o)$; therefore,

$$F_{g} = \left[1 + \frac{F_{\bar{o}o}(C_{\bar{o}o} + R_{s})}{(1 - F_{\bar{o}o})(C_{\bar{o}g} + r_{s}^{-1})}\right]^{-1}, \quad \dots \dots \dots \dots (7.27)$$

with $C_{\overline{o}o}$, $C_{\overline{o}g}$, and R_s in scf/STB and r_s in STB/scf.

Compositions of reservoir oil, x_i , and reservoir gas, y_i , can be calculated from black-oil properties R_s , r_s , and surface properties by

$$y_{i} = \frac{y_{\overline{g}gi} + (C_{\overline{o}g}r_{s})x_{\overline{o}gi}}{1 + C_{\overline{o}g}r_{s}}$$

and $x_{i} = \frac{y_{\overline{g}oi} + (C_{\overline{o}o}/R_{s})x_{\overline{o}oi}}{1 + C_{\overline{o}o}/R}, \quad \dots \qquad (7.28)$

where $y_{\overline{ggi}}$ = average composition of surface gases produced from the reservoir gas; $x_{\overline{ogi}}$ = composition of surface oil produced from the reservoir gas; $y_{\overline{goi}}$ = average composition of surface gases pro-

TABLE 7.2—EOS-CALCULATED SEPARATOR-GAS AND –OIL COMPOSITIONS FROM THREE-STAGE SEPARATION OF ORIGINAL DEWPOINT GAS AND EOS-CALCULATED EQUILIBRIUM OIL

			Reservoir Oil				
Component	У _{sp1}	У _{sp2}	y _{sp3}	У _д	X_{\overline{o}g}	У _{до}	X _{ōo}
CO ₂	0.026092	0.030059	0.036539	0.026388	0.000588	0.027475	0.000627
N ₂	0.003552	0.002154	0.000362	0.003460	5.94×10^{-7}	0.003265	6.12×10 ⁻⁷
C ₁	0.827710	0.809814	0.389891	0.816791	0.002079	0.809754	0.002103
C ₂	0.083029	0.099069	0.209316	0.086288	0.006739	0.090387	0.006730
C ₃	0.033261	0.036388	0.183444	0.036976	0.022803	0.039307	0.022010
<i>i</i> -C ₄	0.005535	0.005410	0.039898	0.006376	0.013315	0.006609	0.012297
<i>n</i> -C ₄	0.010249	0.009582	0.077103	0.011882	0.036997	0.012158	0.033498
<i>i</i> -C ₅	0.003145	0.002559	0.022571	0.003616	0.030334	0.003486	0.026016
<i>n</i> -C ₅	0.002939	0.002287	0.020158	0.003355	0.036413	0.003183	0.030772
C ₆	0.002425	0.001577	0.012855	0.002673	0.081629	0.002398	0.066496
F ₁	0.001671	0.000953	0.007116	0.001798	0.135151	0.001612	0.111360
F ₂	0.000380	0.000141	0.000739	3.87×10^{-4}	0.252945	0.000353	0.221341
F ₃	6.34×10^{-6}	1.03×10^{-6}	2.63×10^{-6}	6.20×10^{-6}	0.223155	6.30×10^{-6}	0.230727
F ₄	7.62×10^{-9}	3.40×10^{-10}	2.76×10^{-10}	7.37×10^{-9}	0.120536	8.91×10^{-9}	0.162246
F ₅	4.10×10^{-13}	2.90×10^{-15}	4.50×10^{-16}	3.93×10^{-13}	0.037312	5.90×10^{-13}	0.073772

TABLE 7.3—RESERVOIR EQUILIBRIUM COMPOSITIONS CALCULATED FROM EOS AND FROM MBO PVT PROPERTIES WITH SURFACE-GAS AND -OIL COMPOSITIONS

	Dewpoint*			Reservoir Pressure**				
	У	X		y		x		
Component	Feed	EOS	EOS	MBO	EOS	MBO		
CO ₂	0.0237	0.0237	0.0245	0.0251	0.0206	0.0189		
N ₂	0.0031	0.0031	0.0034	0.0033	0.0018	0.0022		
C ₁	0.7319	0.7319	0.7817	0.7774	0.5316	0.5517		
C ₂	0.0780	0.0780	0.0791	0.0824	0.0737	0.0637		
C ₃	0.0355	0.0355	0.0344	0.0363	0.0401	0.0338		
i-C ₄	0.0071	0.0071	0.0066	0.0067	0.0090	0.0084		
<i>n</i> -C ₄	0.0145	0.0145	0.0133	0.0131	0.0194	0.0190		
<i>i</i> -C ₅	0.0064	0.0064	0.0056	0.0049	0.0097	0.0107		
<i>n</i> -C ₅	0.0068	0.0068	0.0058	0.0050	0.0106	0.0120		
C ₆	0.0109	0.0109	0.0088	0.0065	0.0194	0.0229		
F ₁	0.0157	0.0157	0.0115	0.0082	0.0325	0.0367		
F ₂	0.0267	0.0267	0.0158	0.0126	0.0704	0.0709		
F ₃	0.0233	0.0233	0.0081	0.0108	0.0841	0.0737		
F ₄	0.0126	0.0126	0.0015	0.0058	0.0573	0.0518		
F ₅	0.0039	0.0039	0.0001	0.0018	0.0196	0.0236		
C ₇₊	0.0821	0.1302	0.0369	0.0393	0.2639	0.2567		
6,750 psia. 4,315 psia.								

duced from the reservoir oil; $x_{\overline{o}oi}$ = composition of surface oil produced from the reservoir oil; and $C_{\overline{o}o}$, $C_{\overline{o}g}$, and R_s are in scf/STB and r_s is in STB/scf.

Average surface-gas compositions $y_{\overline{g}gi}$ and $y_{\overline{g}oi}$ are calculated separately with the relations

$$y_{\bar{g}gi} = \frac{\sum_{j=1}^{N_{sp}} (y_{\bar{g}gi})_j / (r_s)_j}{\sum_{i=1}^{N_{sp}} (1/r_s)_j}, \qquad (7.29)$$

lations $\sum_{j=1}^{j-1} (1)^{j-1}$ where the subs

where the subscript *j* indicates the separator stage. Stage GOR's and OGR's,
$$(R_s)_j$$
 and $(r_s)_j$, respectively, are based on stock-tank volumes.

The four surface compositions (and gravities) are, in principle, functions of pressure. However, the average separator-gas compositions from reservoir oil and from reservoir gas may be similar, and

$$y_{\overline{g}oi} = \frac{\sum_{j=1}^{N_{sp}} (y_{\overline{g}oi})_j (R_s)_j}{\sum_{j=1}^{N_{sp}} (R_s)_j}$$

BLACK-OIL PVT FORMULATIONS



Fig. 7.15—Calculated compositions for reservoir gas based on MBO properties and surface-component compositions; comparison with EOS compositions.

 $y_{\bar{g}gi} = y_{\bar{g}oi} = \text{constant}$ is a reasonable assumption (as is $\gamma_{\bar{g}g} = \gamma_{\bar{g}o} = \text{constant}$). These compositions are readily determined from a multistage flash of the original reservoir mixture (see **Table 7.2**). **Table 7.3 and Figs. 7.15 through 7.17** show calculated reservoir-phase compositions based on Eq. 7.26 for a gas-condensate mixture. *K* values are also calculated ($K_i = y_i/x_i$) and compared with EOS results for a simulated CVD experiment (**Fig. 7.18**).

Wellstream composition, z_i , can be calculated from reservoir phase compositions y_i and x_i .

$$z_i = y_i F_g + x_i (1 - F_g),$$
 (7.30)

where F_g is given by Eq. 7.25 in terms of producing GOR, R_p (through the quantity $F_{\overline{oo}}$). Note that values of R_s and r_s used to calculate F_g , y_i , and x_i must be evaluated at the same pressure.

7.4 Applications of MBO Formulation

The MBO PVT approach has been limited mainly to reservoir simulation, although some applications have been reported in well-test



Fig. 7.17—Calculated compositions for reservoir oil based on MBO properties and surface-component compositions; comparison with EOS compositions.



Fig. 7.16—Calculated methane mole fractions for reservoir oil and gas based on MBO properties and surface-component compositions; comparison with EOS compositions.

analysis, inflow performance, and reservoir material balance. Multiphase flow in pipe is another obvious application. To aid in the use of MBO properties for volatile reservoir fluids, we present several engineering equations in terms of MBO properties.

7.4.1 Rate Equations (IPR)—Traditional Black-Oil PVT. Inflow-performance relations (IPR's) give the relation between total surface rates, $q_{\overline{o}}$ and $q_{\overline{g}}$; wellbore flowing pressure, p_{wf} ; and average reservoir pressure, \overline{p}_{R} . For example, consider the radial-flow equation for an undersaturated oil well.¹³

$$q_{\bar{o}} = q_{\bar{o}o} = \frac{kh(\bar{p}_R - p_{wf})}{141.2\mu_o B_o[\ln(r_e/r_w) - 0.75 + s]}, \quad \dots \quad (7.31)$$

where $q_{\overline{o}}$ is in STB/D, k = absolute permeability at irreducible water saturation, md; h = total reservoir thickness, ft; μ_o = oil viscosity, cp; B_o = oil FVF, bbl/STB; r_e = outer drainage radius, ft; r_w = actual wellbore radius, ft; and s = total skin factor.



Fig. 7.18—Calculated *K* values for reservoir oil and gas based on MBO properties and surface component compositions; comparison with EOS compositions.



Fig. 7.19—Fraction of wellbore rate from reservoir oil, fraction of surface oil from reservoir oil, GOR, and p_{wf} during depletion of a volatile-oil reservoir.

For saturated-oil wells producing both reservoir oil and gas, the oil-rate equation can be written terms of traditional black-oil PVT properties ($r_s = 0$) as

Total gas rate from a saturated-oil well is the product of the oil rate and total producing GOR.

$$q_{\overline{g}} = q_{\overline{o}} R_p, \qquad (7.33)$$

where $q_{\overline{s}}$ is in scf/D and R_p usually is available from material-balance calculations.

The rate of the oil phase flowing anywhere in the tubing or reservoir can be calculated as

$$q_o = q_{\overline{o}} B_o, \qquad (7.34)$$

with q_o in B/D and B_o evaluated at a specific pressure and temperature. The flow rate of free gas at the same conditions is calculated from

with q_g in B/D, $q_{\overline{o}}$ in STB/D, R_s and R_p in scf/STB, and B_{gd} in ft³/scf. R_s and B_{gd} are evaluated at the same pressure and temperature.

7.4.2 IPR—MBO PVT. Eqs. 7.32 and 7.33 are based on the traditional black-oil PVT formulation where reservoir gas is assumed to have no liquid content. For volatile reservoir fluids, the surface oil consists of surface oil from the flowing liquid and condensed from the flowing vapor. Likewise, the surface-gas rate consists of surface gas from the flowing vapor and released from the flowing liquid.

The appropriate equations to calculate rates in the production system are 14,15

$$q_{\bar{o}} = q_{\bar{o}o} + q_{\bar{o}g} = \frac{kh}{141.2[\ln(r_e/r_w) - 0.75 + s]} \\ \times \int_{p_{wf}}^{\dot{p}_R} \left(\frac{k_{ro}}{\mu_o B_o} + 5.615 \frac{k_{rg} r_s}{\mu_g B_{gd}} \right) dp$$

nd
$$q_{\overline{g}} = q_{\overline{g}o} + q_{\overline{g}g} = \frac{\kappa n}{141.2 [\ln(r_e/r_w) - 0.75 + s]}$$

 $\times \int_{p_{wf}}^{\overline{p}_R} \left(\frac{k_{ro}R_s}{\mu_o B_o} + 5.615 \frac{k_{rg}}{\mu_g B_{gd}} \right) dp$, (7.36)

with $q_{\overline{o}}$ in STB/D and $q_{\overline{g}}$ in scf/D.

The liquid and vapor rates in the tubing or reservoir are given by

$$q_o = q_{\overline{o}} F_{\overline{o}o} B_o$$

a

and
$$q_g = q_{\overline{o}} (R_p - R_s F_{\overline{o}o}) B_{gd}$$
, (7.37)

where $F_{\overline{oo}}$ = fraction of total surface oil coming from the flowing liquid (Eq. 7.6).

$$F_{\bar{o}o} = \frac{q_{\bar{o}o}}{q_{\bar{o}}} = \frac{1 - R_p r_s}{1 - R_s r_s}.$$
 (7.38)

PVT properties used to calculate q_o and q_s are evaluated at the pressure and temperature in the reservoir or the production tubing.

Evaluation of the integrals in Eq. 7.36 is not straightforward. In fact, using only one of the two rate equations would be logical, depending on which phase was dominant. For a predominantly oil system, the oil rate in Eq. 7.36 should be used for $q_{\overline{v}}$ and the gas rate could be calculated from the total producing GOR. Likewise, for a predominantly gas system, the gas rate in Eq. 7.36 should be used for $q_{\overline{g}}$ and the oil rate can be calculated from the total producing GOR. Producing GOR would be available from material-balance calculations.

The volumetric fraction of reservoir fluids flowing as an oil phase at wellbore conditions is

$$\frac{q_o}{q_o + q_g} = \frac{q_{\bar{o}}B_o}{q_{\bar{o}}B_o + q_{\bar{g}}B_{gd}} = \left[1 + \frac{\left(R_p - R_s F_{\bar{o}o}\right)B_{gd}}{5.615 F_{\bar{o}o}B_o}\right]^2,$$
(7.39)

where B_o , R_s , B_{gd} , and r_s are evaluated at the wellbore flowing pressure, p_{wf} . For a volatile-oil reservoir, the oil fraction will drop to less than 50% during depletion (see **Fig. 7.19**), marking the point when the gas phase becomes the dominant flowing phase. The relative amounts of reservoir oil and gas flowing at the wellbore should be considered in the interpretation of well tests and application of IPR's.

7.4.3 Reservoir Material Balance—MBO PVT. Reservoir material-balance relations for solution-gas-drive and dry-gas reservoirs are well known and widely used. Borthne¹⁶ presents a reservoir material balance based on MBO properties that can be used for black oils, volatile oils, and gas condensates. Modifications to the material balance that account for connate water with dissolved gas, water influx, and other such factors can be included readily.

The basis of calculation is 1 bbl reservoir bulk volume. The conservation-of-mass equations for a single-cell material balance yields the following difference equations for reservoir-oil and -gas phases during a timestep $\Delta t_k = t_k - t_{k-1}$ with a change in average pressure from $(\overline{p}_R)_{k-1}$ to $(\overline{p}_R)_k$.

TABLE 7.4—MBO PROPERTIES FOR GAS CONDENSATE NS-1									
Pressure (psia)	<i>B</i> o (bbl/STB)	<i>R</i> s (scf/STB)	γ _{ōo}	γ _{go}	B _{gd} (ft ³ /scf)	r _s (STB/MMscf)	γ _{ōg}	γ _{gg}	$F_{\overline{g}g}$
6,748.2	2.6490	3,005	0.7837	0.7155	0.004244	181.0	0.7689	0.7114	0.8958
6,514.7	2.4693	2,662	0.7849	0.7171	0.004205	158.2	0.7647	0.7110	0.9051
6,014.7	2.2241	2,180	0.7859	0.7208	0.004226	125.7	0.7575	0.7107	0.9194
5,514.7	2.0495	1,829	0.7859	0.7251	0.004333	102.4	0.7516	0.7106	0.9306
4,314.7	1.7427	1,211	0.7845	0.7397	0.004940	64.0	0.7399	0.7114	0.9516
3,114.7	1.5116	757	0.7832	0.7629	0.006371	39.3	0.7298	0.7139	0.9677
2,114.7	1.3525	456	0.7829	0.7927	0.009179	26.2	0.7224	0.7181	0.9772
1,214.7	1.2277	232	0.7843	0.8324	0.016214	21.2	0.7151	0.7268	0.9808
714.7	1.1651	124	0.7864	0.8663	0.028276	24.7	0.7088	0.7386	0.9771
Water $\gamma = 1$.									

where ΔN_p and ΔG_p = incremental quantities of total surface oil and total surface gas, respectively, produced during the timestep;

$$A_o = \phi \left[\frac{S_o}{B_o} + \frac{5.615(1 - S_w - S_o)r_s\gamma_{\overline{o}}^*}{B_{gd}} \right]$$

and $A_g = \phi \left[\frac{S_o R_s \gamma_{\overline{g}}^*}{B_o} + \frac{5.615(1 - S_w - S_o)}{B_{gd}} \right]; \quad \dots \quad (7.41)$
and $\gamma_{\overline{o}}^* = \frac{\gamma_{\overline{o}g}}{W_{\overline{o}g}}$

and
$$\gamma_{\overline{g}}^* = \frac{\gamma_{\overline{go}}}{\gamma_{\overline{gg}}}$$
. (7.42)

In Eqs. 7.40 through 7.42, ΔN_p and A_o are in STB/bbl, ΔG_p and A_g are in scf/bbl, R_s is in scf/STB, B_o is in bbl/STB, r_s is in STB/scf, and B_{gd} is in ft³/scf. Other quantities used in the material-balance procedure are

$$E_{o} = 1 + 5.615r_{s}\gamma_{\bar{o}}^{*}\frac{k_{rg}\mu_{o}B_{o}}{k_{ro}\mu_{g}B_{gd}},$$

$$E_{g} = R_{s}\gamma_{\bar{g}}^{*} + 5.615\frac{k_{rg}\mu_{o}B_{o}}{k_{ro}\mu_{g}B_{gd}},$$

$$R_{p} = \frac{\Delta G_{p}}{\Delta N_{p}},$$

$$k$$

and $\frac{k_{rg}}{k_{ro}} = f(S_o)$, (7.43)

with μ_o and μ_g in cp; R_s , R_p , and E_g in scf/STB; r_s in STB/scf; E_o in STB/STB; B_o in bbl/STB; and B_{gd} in ft³/scf. PVT properties and porosity are $(\gamma_{\overline{g}}^*)_k$ functions of pressure only. Application of these relations is outlined for an oil and a gas-condensate reservoir. *Oil Becarroir*

Oil Reservoir.

1. Specify $(\Delta N_p)_k$, the total surface oil produced in STB/bbl of bulk volume.

2. Assume $(\overline{p}_R)_k$ and calculate PVT properties and porosity: $(B_o)_k, (R_s)_k, (\mu_o)_k, (\gamma_{\overline{o}}^*)_k, (B_{gd})_k, (r_s)_k, (\mu_g)_k, (\gamma_{\overline{g}}^*)_k$, and $(\phi)_k$. 3. Calculate oil saturation $(S_o)_k$ from Eqs. 7.39 through 7.41.

$$(S_o)_k = \frac{(A_o)_{k-1} - (\Delta N_p)_k - [\phi(1 - S_{wi})r_s\gamma_{\sigma}^*/B_{gd}]_k}{[\phi(1/B_o - r_s\gamma_{\sigma}^*/B_{gd})]_k}.$$

4. Calculate $(k_{rg}/k_{ro})_k$ from $(S_o)_k$.

5. Calculate $(A_o)_k, (A_g)_k, (E_o)_k$, and $(E_g)_k$.

6. Calculate ΔN_{po} , incremental surface oil produced from reservoir oil, where $\Delta N_{po} = \Delta N_p / \overline{E}_o$ and $\overline{E}_o = 0.5[(E_o)_k + (E_o)_{k-1}]$.

7. Calculate ΔG_p , incremental total surface gas produced, where $\Delta G_p = \Delta N_{po} \overline{E}_g$ and $\overline{E}_g = 0.5[(E_g)_k + (E_g)_{k-1}]$. 8. Calculate the material-balance error,

 $\varepsilon = (A_g)_k - (A_g)_{k-1} + \Delta G_p. \quad \dots \quad \dots \quad \dots \quad \dots \quad (7.45)$

9. If ε is not sufficiently small, assume a new pressure $(\overline{p}_R)_k$ and redo Steps 2 through 8.

Gas-Condensate Reservoir.

1. Specify $(\Delta G_p)_k$, total surface gas produced in scf/bbl of bulk volume.

2. Assume $(\overline{p}_R)_k$ and calculate PVT properties and porosity: $(B_o)_k, (R_s)_k, (\mu_o)_k, (\gamma_{\overline{\sigma}}^*)_k, (B_{gd})_k, (r_s)_k, (\mu_g)_k, (\gamma_{\overline{g}}^*)_k$, and $(\phi)_k$. 3. Calculate oil saturation $(S_o)_k$ from Eqs. 7.39 through 7.41.

$$(S_o)_k = \frac{(A_g)_{k-1} - (\Delta G_p)_k - [\phi(1 - S_{wi})/B_{gd}]_k}{[\phi(R_s \gamma_g^*/B_o - 1/B_{gd})]_k}.$$
 (7.46)

4. Calculate $(k_{rg}/k_{ro})_k$ from $(S_o)_k$.

5. Calculate $(A_o)_k, (A_g)_k, (E_o)_k$, and $(E_g)_k$.

6. Calculate ΔN_{po} , incremental surface oil produced from reservoir oil, where $\Delta N_{po} = \Delta G_p / \overline{E}_g$ and $\overline{E}_g = 0.5[(E_g)_k + (E_g)_{k-1}]$.

7. Calculate ΔN_{p} incremental total surface oil produced, where $\Delta N_{po} = \Delta N_p / \overline{E}_o$ and $\overline{E}_o = 0.5[(E_o)_k + (E_o)_{k-1}]$. 8. Calculate the material-balance error,

$$\varepsilon = (A_o)_k - (A_o)_{k-1} + \Delta N_p. \qquad (7.47)$$

9. If ε is not sufficiently small, assume a new pressure $(\overline{p}_R)_k$ and redo Steps 2 through 8.

7.5 Partial-Density Formulation

In 1965, Kniazeff and Naville⁷ presented the first approach to modeling gas-condensate and volatile-oil systems with a simplified compositional PVT formulation. They introduced four "partial densities" as PVT parameters in a radial, 1D numerical model to study the inflow performance of a Middle East gas–condensate field. The flow and conservation equations were written in terms of mass, where surface volumes were not considered directly.

Partial densities, ρ_p , are defined as

$$\rho_{pij} = \frac{m_{ij}}{V_i}, \qquad (7.48)$$

where m_{ij} = surface mass of Component *i* in Phase *j*; V_j = reservoir volume of Phase *j*; *i* = *g* and *o* = surface gas and oil, respectively; and *j* = *g* and *o* = reservoir gas and oil, respectively. The four partial densities, ρ_p , can be expressed as composite terms of MBO properties.

$$\rho_{p\overline{g}g} = \frac{0.0763\gamma_{\overline{g}g}}{B_{gd}},$$
$$\rho_{p\overline{o}g} = \frac{350\gamma_{\overline{o}g}r_s}{B_{gd}},$$



Fig. 7.20—Partial densities vs. pressure for Gas-Condensate NS-1.

$$\rho_{p\bar{g}o} = \frac{0.0136\gamma_{\bar{g}o}R_s}{B_o},$$

$$rd \rho_{o} = -\frac{62.4\gamma_{\bar{o}o}}{B_o}$$
(7.40)

with
$$\rho_{p\bar{o}o} = \frac{B_o}{B_o}$$
, (7.49)

with ρ_p in iom/it², B_o in obj/STB, K_s in sci/STB, B_{gd} in it²/sci, and r_s in STB/scf. **Table 7.4 and Fig. 7.20** show the behavior of partial densities and their relation to MBO properties.

From Eq. 7.47, we see that the variation in surface gravities with pressure is included directly in the definitions of the PVT properties. In fact, this is necessary to maintain an exact mass balance. Drohm and Goldthorpe⁹ and Drohm *et al.*^{10,11} indicate that a similar approach can be used for reservoir simulators on the basis of the MBO approach. They correct the MBO parameters with surface densities, which indicates that an exact mass balance can be maintained if the corrected properties (B_o^* , R_s^* , B_{gd}^* and r_s^*) are used instead of the original parameters (B_o , R_s , B_{gd} , and r_s).

$$B_o^* = \frac{B_o}{62.4\gamma_{\overline{o}o}},$$

$$R_s^* = R_s \left(\frac{\gamma_{\overline{g}o}}{\gamma_{\overline{o}o}}\right),$$

$$B_{gd}^* = \frac{B_{gd}}{62.4\gamma_{\overline{g}g}},$$

$$(\alpha , \beta)$$

and
$$r_s^* = r_s \left(\frac{\gamma_{\overline{og}}}{\gamma_{\overline{gg}}} \right)$$
, (7.50)

with densities in lbm/ft³, B_o in bbl/STB, R_s in scf/STB, B_{gd} in ft³/scf, and r_s in STB/scf. Reservoir models based on the Drohm-Goldthorpe or the partial-density approach still do not yield a consistent surface-volume material balance unless surface gravities are considered pressure dependent.

7.6 Modifications for Gas Injection

Cook *et al.*⁵ extend the MBO formulation for vaporizing-gas-injection processes, where a gas-injection parameter, G_i , is defined as the cumulative volume of injection gas entering a grid cell, divided by the grid-cell volume. PVT properties B_o , R_s , B_{gd} , and r_s are correlated in tabular form vs. G_i (see **Fig. 7.21**). Lo and Youngren,¹⁷ Whitson *et al.*,¹⁸ and others propose other extensions to the MBO formulation.



Fig. 7.21—Variation in black-oil PVT properties with gas-injection parameter G_i (adapted from Ref. 5).

The complexity of some formulations is disturbing because so many nonphysical quantities are used to correlate compositional effects.

With the increasing speed of compositional simulators and the increase in available computing power, it is difficult to justify the effort to develop these highly empirical, pseudo-PVT formulations for gasinjection projects where compositional effects are important. If a simplified formulation is used, it should be checked with a compositional formulation. Tang and Zick¹⁹ recently proposed and interesting and accurate pseudocompositional model with the computational speed of a black-oil model and the accuracy of an EOS model that is of particular interest in miscible-gas-injection simulations.

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SI Metric Conversion Factors

°API	141.5/(131.5 +	- °API)	$= g/cm^3$
bbl	×1.589 873	E - 01	$= m^3$
ft ³	×2.831 685	E - 02	$= m^{3}$
°F	(°F-32)/1.8		=°C
lbm	×4.535 924	E - 01	=kg
lbm mol	×4.535 924	E - 01	= kmol
psi	×6.894 757	E + 00	=kPa