Volatile Oil Fluid @model

Synonym: Modified Black Oil fluid @model = MBO fluid @model = Volatile Oil fluid @model

Specific case of a 3-phase fluid model based on three pseudo-components $C = \{W, O, G\}$:

W	water pseudo-component, which may include minerals (assuming formation water and injection water composition is the same)
O	dead oil pseudo-component
G	dry gas pseudo-component

existing in three possible phases $\alpha = \{w, o, g\}$:

w	water phase, consisting of Water component only
o	oil phase, consisting of dead Oil pseudo-component and dissolved dry Gas pseudo-componentt (called Solution Gas)
g	gas phase, consisting of dry Gas pseudo-component and vaporized dead Oil pseudo-component (called volatile oil)

The volumetric phase-balance equations is:

(1) $$s_w + s_o + s_g = 1$$

where

$s_w = \frac{V_w}{V}$	share of total fluid volume V occupied by water phase V_w
$s_o = \frac{V_o}{V}$	share of total fluid volume V occupied by oil phase V_o
$s_g = \frac{V_g}{V}$	share of total fluid volume V occupied by gas phase V_g

The accountable cross-phase exchanges are illustrated in the table below:

	w	o	g
W			
O			
G			

Modified Black Oil fluid @model is widely used to model Volatile Oil Reservoir and Pipe Flow Simulations.

The relations between in-situ (at given temperature and pressure) and STP masses, volumes, densities and compressibilities are given by the following equations (see Derivation):

(2) $V_O = \frac{V_o}{B_o} + R_v \frac{V_g}{B_g}$	(3) $V_G = \frac{V_g}{B_g} + R_s \frac{V_o}{B_o}$	(4) $V_W = \frac{q_w}{B_w}$	(5) $V_L = V_O + V_W$
(6) $V_o = \frac{B_o \cdot (V_O - R_v V_G)}{1 - R_v R_s}$	(7) $V_g = \frac{B_g \cdot (V_G - R_s V_O)}{1 - R_v R_s}$	(8) $V_w = B_w \cdot V_W$	(9) $V_t = V_o + V_g + V_w$
In-situ oil-cut: (10) $s_o = V_o / V_t$	In-situ gas-cut: (11) $s_g = V_g / V_t$	In-situ water-cut: (12) $s_w = V_w / V_t$	(13) $s_o + s_g + s_w = 1$
Surface oil mass rate: (14) $m_O = \rho_O V_O$	Surface gas mass rate: (15) $m_G = \rho_G V_G$	Surface gas mass rate: (16) $m_W = \rho_W V_W$	Surface total fluid mass rate: (17) $m = m_O + m_G + m_W$
In-situ oil mass: (18) $m_o = (\rho_O + \rho_G \cdot R_s) \cdot \frac{V_o}{B_o}$	In-situ gas mass: (19) $m_g = (\rho_G + \rho_O \cdot R_v) \cdot \frac{V_g}{B_g}$	In-situ water mass: (20) $m_w = \rho_W \cdot V_w / B_w$	In-situ total fluid mass: (21) $m = m_o + m_g + m_w$
In-situ oil density: (22) $\rho_o = \frac{\rho_O + \rho_G \cdot R_s}{B_o}$	In-situ gas density: (23) $\rho_g = \frac{\rho_G + \rho_O \cdot R_v}{B_g}$	In-situ water density: (24) $\rho_w = \frac{\rho_W}{B_w}$	In-situ Total fluid density: (25) $\rho_t = m/V_t = s_o \rho_o + s_g \rho_g + s_w \rho$
In-situ total fluid compressibility: (26) $c = \rho_t^{-1} \cdot (s_o \rho_o c_o + s_g \rho_g c_g + s_w \rho_w c_w)$			

where B_o, B_g, B_w, R_s, R_v are Dynamic fluid properties.

See Also

Petroleum Industry / Upstream / Subsurface E&P Disciplines / Fluid (PVT) Analysis / Fluid @model

[Volatile Oil][Volatile Oil Reservoir][PVT correlations][Oil correlations][Gas correlations][Water correlations]

[Dynamic fluid properties]