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New Referencing Technique for Reservoir Oil Viscosity Estimation

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Abstract

Reservoir oil viscosity is important in understanding reservoir flow behaviour, facilities design and sizing and in the computation of recovery performance, well productivity and lift requirements. Direct viscosity measurements are expensive or sometimes unavailable hence empirical correlations are often used for predictions. However, several published correlations are either too simplistic or complex for routine operational use and improved methods continue to receive attention. This study used a semi-theoretical approach to relate reservoir oil viscosity to well-head oil viscosity which can easily be obtained. Results were analyzed statistically and tested with field data obtained from the Niger Delta. The viscosity relation factors developed gave an absolute average relative error (AARE) of 14.1% for undersaturated reservoirs and an AARE of 2.4% for saturated oil reservoirs. It is concluded that measured well-head oil viscosity can be used with good accuracy, as reference liquid instead of dead oil viscosity that has been commonly used for estimating reservoir viscosity.

Keywords: Crude oil viscosity, referencing technique, viscosity correlations, Niger Delta

Introduction and Literature Review

Viscosity is an important property of reservoir fluids. It is used during reservoir flow calculations, design of pipelines, production equipment and pump sizing, in oil well testing calculations and reservoir simulation. Several methods have been employed to model reservoir oil viscosity. However, the self-referencing methods, seem to have been most successful, with the use of dead oil viscosity as the reference point.

There are several viscosity correlations that are commonly used in the oil industry today. They include those by Glaso (1980), Dindoruk, B., and Christman (2001) and several others. The work by Amoo and Isehunwa (1990) specifically on Niger Delta crudes, used only oil specific gravity as the main correlating parameter for estimating viscosity. This limited its accuracy to estimates above bubble point. Kulchanyavivat (2005) has noted the significance of choosing the right parameters for correlating viscosity of reservoir oil and developed a self-referencing model for estimating the viscosity of petroleum liquids and dead oils under operating conditions. The model utilized only the measured viscosity at atmospheric pressure and room temperature. However, the correlation uses nine coefficients, making it rather complex for routine applications.

In this work, following the method of Umeh et. al. (2003), surface oil viscosity obtained from the well head was adopted as referencing point for estimating reservoir oil viscosity. Eze and Ajienka (2006) have noted that subsurface conditions in oil wells may be monitored real time through the use of surface data.

Theoretical Framework

For an undersaturated oil reservoir, the pseudo-steady state solution for flow can be expressed as:

$$q_o = \frac{7.08kh}{\left[\ln\left(\frac{r_e}{r_w}\right)-\frac{3}{4}+s'\right]}\left[\int_{P_{wf}}^{P_b}\frac{k_{ro}(S,P)}{\mu_o B_o}dp + \frac{\left(\overline{P}_R - P_b\right)}{\left(\mu_o B_o\right)_{\overline{P}_R, P_{wf}}}\right] \quad (1)$$

When a single phase is following in the reservoir, equation (1) reduces to:

$$q_o = \frac{7.08kh\left(\overline{P}_R - P_{wf}\right)}{\left[\ln\left(\frac{r_e}{r_w}\right)-\frac{3}{4}+s'\right]\left(\overline{\mu_o B_o}\right)} \quad (2)$$

Equation (2) can be expressed as:

$$q_o = C_r\frac{1}{\mu_o B_o}\left(\overline{P}_R - P_{wf}\right) \quad (3)$$

Where,

$$C_r = \frac{7.08kh}{\left[\ln\left(\frac{r_e}{r_w}\right)-\frac{3}{4}+s'\right]} \quad (4)$$

At the well head, using Ros (1960) equation for choke performance, we have:

$$P_{th} = \frac{17.4R_s^{0.5}q}{d^2} \quad (5)$$

Thus,

$$q_o = \frac{d^2}{17.4R_s^{0.5}}P_{th} \quad (6)$$

By equating equations (3) and (6), and simplifying we have:

$$\mu_o = \frac{17.4C_r R_s^{0.5}}{d^2 B_o}\frac{\left(\overline{P}_R - P_{wf}\right)}{P_{th}} \quad (7)$$

Equation (7) shows that reservoir oil viscosity can be expressed in terms of oil PVT properties, formation properties, choke dimensions, flowing well and tubing head pressures.

At surface, oil volumetric flow rate can be calculated from the equation for multiphase sub-critical flow through the wellhead choke given as:

$$Q_L = 0.25C_d d^2\sqrt{\frac{\left(P_{th} - P_{ds}\right)}{\rho_L}} \quad (8)$$

The liquid flow rate can also be calculated by treating the wellhead choke as a smooth pipe. Recall the equation for flow through a horizontal pipe:

$$Q_L = 3574.42E_L\left[\frac{D^{19}}{\mu_L\rho_L^3}\left(\frac{\Delta P_f}{L}\right)^4\right]^{\frac{1}{7}} \quad (9)$$

Replacing pipeline diameter, D and length L are replaced with choke diameter, d and length l gives the equation for flow through a wellhead choke. It becomes

$$Q_L = 3574.42 E_L \left[\frac{d^{19}}{\mu_L \rho_L^{3}} \left(\frac{\Delta P_f}{l} \right)^4 \right]^{\frac{1}{7}} \tag{10}$$

Converting pipeline diameter inches to 1/64 inches in Eq. (10) gives

$$Q_L = 0.044742 E_L \left[\frac{d^{19}}{\mu_L \rho_L^{3}} \left(\frac{\Delta P_f}{l} \right)^4 \right]^{\frac{1}{7}} \tag{11}$$

Surface oil viscosity can be calculated by equating Eqs. (8) and (11) to give:

$$\mu_L = 5.881 \times 10^{-6} \frac{C_d^7 d^5 (\rho_L (P_{th} - P_{ds}))^{0.5}}{E_L^7 l^4} \tag{12}$$

When critical flow occurs, the choke upstream pressure is about twice the downstream pressure i.e. $P_{ds}/P_{th} \approx 0.5$. Thus, Eq. (12) becomes

$$\mu_L = 4.16 \times 10^{-6} \frac{C_d^7 d^5 (\rho_L P_{th})^{0.5}}{E_L^7 l^4} \tag{13}$$

From Eqns. (7) and (13) we have:

$$\frac{\mu_o}{\mu_L} = 4184432 \frac{E_L^7 l^4 C_r}{C_d^7 d^7} \frac{R_s^{0.5}}{\rho_L^{0.5} B_o} \frac{(\bar{p}_R - p_{wf})}{P_{th}^{1.5}} \tag{14}$$

Using Umeh et al (2003), we define a viscosity relation factor, VRF as:

$$VRF = \frac{\mu_{o,sc}}{\mu_{o,rc} \rho_{o\,sc}} \tag{15}$$

Therefore, substituting equation (14) into (15) and simplifying we have:

$$VRF = 2.39 \times 10^{-7} C_{DIM} C_{PR} \frac{B_o}{R_s^{0.5} \rho_L^{0.5}} \tag{16}$$

Where,

$$C_{DIM} = \frac{C_{ch}}{C_r} \tag{17}$$

$$C_{ch} = \frac{C_d^7 d^7}{E_L^7 l^4} \tag{18}$$

$$C_{PR} = \frac{P_{th}^{1.5}}{(\bar{P}_R - P_{wf})} \tag{19}$$

Similarly for saturated reservoirs, viscosity relation factor is expressed as:

$$VRF = 9.56 \times 10^{-9} C_{DIM} C_{PR} \frac{B_o T_R}{R_s^{0.5} \rho_L^{0.5}} \tag{20}$$

Where,

$$C_{PR} = \frac{\bar{p}_R P_{th}^{1.5}}{(\bar{p}_R^{\,2} - p_{wf}^{\,2})}$$

Model Validation and Discussion of Results

Equations (16) and (20) are the equations that relate well head viscosity to reservoir viscosity in undersaturated and saturated reservoirs respectivpely. It is clear however that some empirical data are required before they can be used. The input parameters for the models are summarized in Table 1. However, field data should be used where available.

Table 1: Input Parameters

Field Property	Specification
Drawdown, $(p_R - p_{wf})$	≈ 5%
Well radius, r_e	0.3ft or 0.5ft
Absolute Permeability, k	1000md
Relative Permeability, k_{ro}	≈ 0.8
Skin, s	0
Choke diameter, d	≥ 16/64ths in
Choke length, l	≤ 6 in

The equpations were validated with data obtained from Shell Field A in the Niger Delta as published by Umeh et al (2003). A summary of the range of the field data is shown Table 2.

Table 2: The range of the data used in model validation (from Umeh, et al, 2003)

PVT Property	Saturated Reservoirs	Undersaturated Reservoirs
Reservoir Oil Viscosity, cp	0.8 – 12.69	6.67 – 36.17
Surface Oil Viscosity, cSt	6.44 – 114.2	22.66 – 121.90
Bubble Point Pressure, psia	642 – 3995	391 – 1995
Initial Solution Gas Oil Ratio, scf/stb	198 – 600	45 – 232
Oil Density @ reservoir conditions	0.76 – 0.875	0.76 – 0.875
Relative Oil Density	0.89 – 0.95	0.92 – 0.95
Reservoir Temperature, °F	120 – 165	120 – 180
Initial oil formation volume factor, rb/stb	1.09 – 1.32	1.06 – 1.16
Well head Temperature, °F	100	100

The results for seven undersaturated oil reservoirs are presented in Tables 3 - 6. Statistical analysis in Table 4 established the accuracy of the viscosity relation factors.

Table 3: Predicted and Actual viscosity relation factors in some undersaturated reservoirs

Reservoir	Estimated VRF	Field VRF	Average Error (%)
A11	3.33	3.37	-1.19
A21	3.17	3.61	-12.19
A31	7.61	5.44	39.89
A41	5.78	4.50	28.44
A51	3.30	3.40	-2.94
A61	3.71	3.40	9.12
A71	3.14	3.31	-5.14

Table 4: Statistical accuracy of VRF in selected undersaturated reservoirs

	This Study (Estimated VRF)
Average Relative Error, ARE	8.00
Average Absolute Relative Error, AARE	14.13
Coefficient of Correlation, R^2	0.97

Table 5: Predicted and Actual reservoir oil viscosity (cP) in some undersaturated reservoirs

Reservoir	Estimated $\mu_{o,rc}$	Field $\mu_{o,rc}$	Average Error (%)
A11	36.12	36.17	-0.14
A21	33.94	34.2	-0.76
A31	5.10	4.88	4.51
A41	6.54	5.14	27.24
A51	6.27	6.67	-6.00
A61	7.01	6.90	1.59
A71	6.97	7.03	-0.85

Table 6: Predicted and Actual surface oil viscosity (cSt) in some undersaturated reservoirs

Reservoir	Predicted $\mu_{o,sc}$	Measured $\mu_{o,sc}$	Average Error (%)
A11	113.04	114.59	-1.35
A21	102.3	117.14	-12.67
A31	36.67	24.67	48.64
A41	34.76	21.27	63.42
A51	19.00	20.85	-8.87
A61	23.96	21.59	10.98
A71	20.19	21.39	-5.61

The models gave better predictions of reservoir viscosity than surface oil viscosity as can be seen from Tables 5 and 6.

The results for five saturated oil reservoirs of Field A are presented Tables 7 - 10. Statistical analysis confirms low average errors and high coefficient of correlation.

Table 7: Predicted and Actual viscosity relation factors for selected saturated reservoirs

Reservoir	Predicted VRF	Measured VRF	Average Error (%)
A12	8.96	9.00	-0.44
A22	8.90	9.00	-1.11
A32	8.61	8.69	-0.92
A42	10.25	10.68	-4.03
A52	8.51	8.05	5.71

Table 8: Statistical accuracy of predicted VRF in selected saturated reservoirs

	This Study (Estimated VRF)
Average Relative Error (%), ARE	0.16
Average Absolute Relative Error (%), AARE	2.44
Coefficient of Correlation, R^2	0.96

Table 9: Predicted and Actual reservoir oil viscosity (cP) in selected saturated reservoirs

Reservoir	Estimated $\mu_{o,rc}$	Field $\mu_{o,rc}$	Average Error (%)
A12	12.14	12.69	-4.33
A22	0.77	0.84	-8.33
A32	0.90	1.08	-16.67
A42	9.34	10.71	-12.79
A52	0.86	0.80	7.50

Table 10: Predicted and Actual surface oil viscosity (Cst) in selected saturated reservoirs

Reservoir	Estimated $\mu_{o,sc}$	Field $\mu_{o,sc}$	Average Error (%)
A12	102.22	107.35	-4.78

Table 10: Predicted and Actual surface oil viscosity (Cst) in selected saturated reservoirs - continued

A22	6.10	6.73	-9.34
A32	6.97	8.45	-17.53
A42	91.03	108.68	-16.24
A52	6.52	5.73	13.76

Cashe Study: Oilfield B

B is another Niger Delta oilfield whose data were used in the model validation. The PVT data ranges are given in Tapble 11:

Figure 2: Oil PVT properties vs. VRF in Undersaturated Reservoirs for B Oilfield

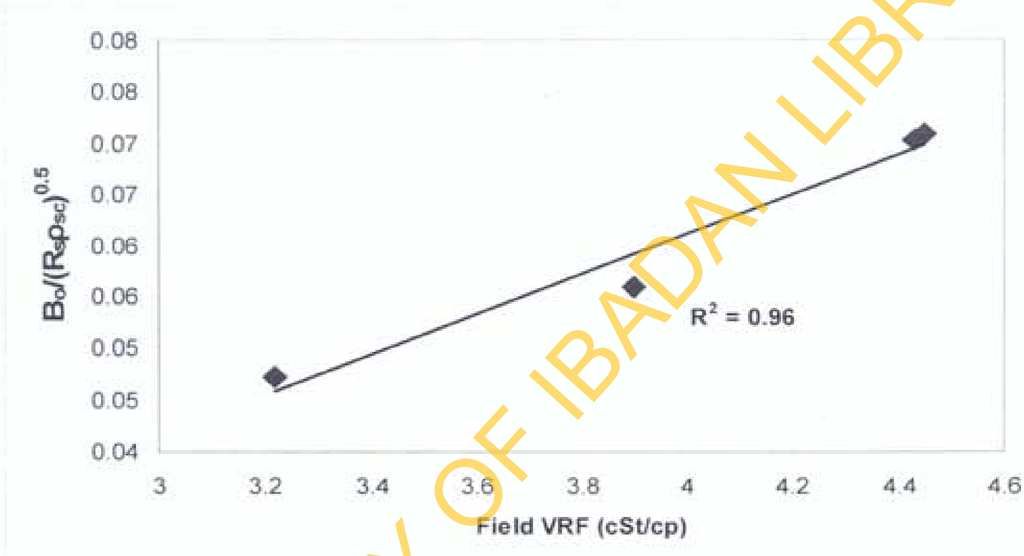
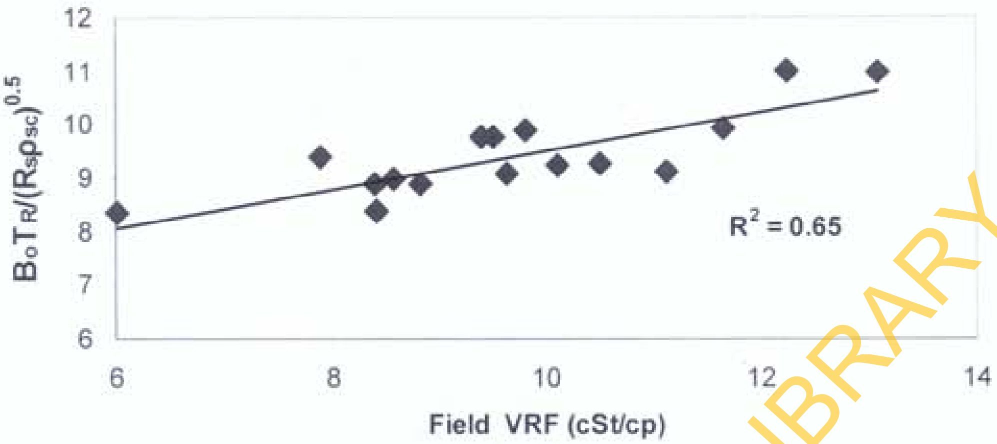


Table 11: Summarty of the data for Odidi Oilfield

Saturated Reservoirs	
PVT Property	**Range**
Reservoir Oil Viscosity	0.23 – 4.06 cp
Surface Oil Viscosity	2.68 – 42 cSt
Bubble Point Pressure	2770 – 5038 psia
Initial Solution Gas Oil Ratio	333 – 1840 scf/stb
Oil Density @ reservoir conditions	0.582 – 0.852
Relative Oil Density	0.823 – 0.93
Temperature	142 – 246 °F
Initial oil formation volume factor	1.129 – 1.874 rb/stb
Undersaturated Reservoirs	
Reservoir Oil Viscosity	1.01 – 9.149 cp
Surface Oil Viscosity	0.27 – 37.5 cSt
Bubble Point Pressure	2142 – 5505 psia
Initial Solution Gas Oil Ratio	266 – 1809 scf/stb
Oil Density @ reservoir conditions	0.537 – 0.851
Relative Oil Density	0.839 – 0.925
Temperature	144 – 270 °F
Initial oil formation volume factor	1.112 – 1.84 rb/stb

Figure 3: Oil PVT properties vs. VRF in Saturated Reservoirs for B Oilfield



The results for four undersaturated and four saturated oil reservoirs of the B oilfield are presented in Tables 12 and 13. The viscosity relation factor model for undersaturated oil reservoirs performed better than the model for saturated oil reservoirs.

Table 12: Comparison of estimated viscosity relation factors with field viscosity relation factors for undersaturated reservoirs for B Field

Reservoir	Estimated VRF	Field VRF	Average Error (%)
B11	3.66	3.90	-6.15
B21	3.18	3.22	-1.24
B31	4.55	4.45	2.25
B41	3.97	4.43	-10.38

Table 13: Comparison of estimated viscosity relation factors with field viscosity relation factors for saturated reservoirs for B Field

Reservoir	Estimated VRF	Field VRF	Average Error (%)
B12	8.13	13.63	-40.35
B22	8.78	9.81	-10.50
B32	8.83	11.65	-24.21
B42	8.41	9.40	-10.53

Conclusion

A theoretical framework has been established for relating surface oil viscosity to reservoir oil viscosity using PVT data, reservoir rock properties and production string dimensions. Empirical models developed developed and validated with data from two oil fields in the Niger Delta show that wellhead viscosity can be a good reference point for estimating reservoir oil viscosity.

Nomenclature

A	-	Area, ft^2
°API	-	Oil gravity, °API
B_o	-	Oil formation volume factor, RB/STB
C_d	-	Discharge coefficient

d	-	Choke diameter, 1/64th in.
E_L	-	Liquid holdup
f	-	Moody friction factor
g	-	Acceleration due to gravity (32.2 ft/s^2)
k	-	Absolute permeability, md
k_o	-	Effective permeability to oil, md
k_{ro}	-	Relative permeability for oil
OVF	-	Oil formation viscosity factor, cp/cp
P	-	Pressure, psia
P_{ds}	-	Choke downstream pressure, psia
P_e	-	Reservoir boundary pressure, psia
P_R	-	Average reservoir pressure, psia
P_{th}	-	Tubing head pressure, psia
P_{wf}	-	Flowing well pressure, psia
P_{wh}	-	Well head pressure, psia
ΔP_f	-	Pressure loss due to friction effects (psi)
Q, q	-	Production rate (Volumetric Flow rate), STB/D
r_e	-	Drainage radius, ft
r_w	-	Well radius, ft
Re	-	Reynolds number
R_s	-	Solution gas-oil ratio, SCF/STB
s	-	Oil Saturation
s'	-	Skin factor
T_R	-	Average reservoir temperature, °F
v	-	Average velocity, ft/s
v_{sg}	-	Superficial gas velocity, ft/s
v_{sl}	-	Superficial liquid velocity, ft/s
VRF	-	Viscosity relation factor, cSt/cp

Greek Letters

β	-	Diameter ratio (*d/D*)
ρ	-	Density (g/cm^3)
γ_o	-	Oil relative density at 14.7 psia and 60°F
μ_o	-	Oil viscosity, cp
μ_{ob}	-	Bubble point oil viscosity, cp

Subscripts

1	-	Inlet
2	-	Outlet
b	-	Bubble point
g	-	Gas
i	-	Initial conditions
L	-	Liquid
o	-	Oil
r	-	Reduced conditions
sc	-	Surface conditions
rc	-	Reservoir conditions

Abbreviation

ARE	-	Average relative error
AARE	-	Average absolute relative error
GOR	-	Gas-oil ratio
PVT	-	Pressure-Volume-Temperature
SPDC	-	Shell Petroleum Development Company

Statistical Criteria

$$ARE = \frac{100}{N}\sum_{i=1}^{N}\frac{X_{i_{calc}} - X_{i_{meam}}}{X_{i_{meam}}}$$

$$AARE = \frac{100}{N}\sum_{i=1}^{N}\left|\frac{X_{i_{calc}} - X_{i_{meam}}}{X_{i_{meam}}}\right|$$

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