COMPARISON OF PVT CORRELATIONS FOR PREDICTING CRUDE OIL PROPERTIES: THE BRAZILIAN CAMPOS BASIN CASE STUDY

^a Mangili, P. V.¹; ^a Ahón, V. R. R.

^a Fluminense Federal University, Department of Chemical and Petroleum Engineering, Niterói - RJ - Brazil

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ABSTRACT

Pressure-Volume-Temperature correlations are essential for estimating the required parameters necessary for the identification of reservoir fluid properties when experimental laboratory data are not readily available. Although several models have been published for different oil fields, there is a lack of studies addressing the Brazilian pre-salt region. Hence, in this paper we compared twenty empirical correlations for the determination of the solution gas-oil ratio, oil formation-volume-factor, and under-saturated oil viscosity for Brazilian pre-salt oil samples collected from the Campos Basin region, originally evaluated by **Elias and Trevisan (2016)**. From our statistical results, some models presented good estimation performances when compared to said reference's results. In fact, through a statistical analysis, Al-Shammasi (2001)'s correlation proved to be the best estimation method for solution gas-oil ratio, whereas **Al-Marhoun (1985)** and **Beal's (1946)** correlations were deemed the most accurate for the prediction of oil formation-volume-factor and under-saturated oil viscosity, respectively.

KEYWORDS

Campos Basin; oil formation-volume-factor; PVT correlations; gas-oil ratio solution; under-saturated oil viscosity

¹ To whom all correspondence should be addressed.

Address: Fluminense Federal University, Department of Chemical and Petroleum Engineering, Niterói - RJ - Brazil.

ZIP Code: 24210-240 | e-mail: pmangili@id.uff.br

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1. INTRODUCTION

The oil and gas industry may be deemed one of the most dynamic engineering spheres to be studied. This is due to not only the wearying technical knowledge required to provide the community with fine, daily life-demand commodities but also the wavy behavior associated with such an industry. In fact, the **Management Centre Europe (2018)** stated that the petroleum market has been facing notable oscillations in the last decades, especially with regard to the new finds – which are located more frequently in remote areas – and the changes in supply and demand necessities driven mainly by population growth, globalization, and climate change.

In light of such dynamics, the oil and gas companies have been committed to either developing new techniques or improving already-existing strategies to produce the so-called “black gold.” Therefore, understanding the phase behavior of hydrocarbons present in the reservoir is of utmost importance, since it is highly necessary for process design (**Rasouli et al., 2008**), evaluation of reservoir performance (**Elsharkawy et al., 1995**), and field development (**Torabi et al., 2014**). The thermodynamic behavior of petroleum fluids can be determined through Pressure-Volume-Temperature (PVT) tests, which are conducted on laboratory samples collected *in situ*. PVT analyses are essential for providing the required parameters necessary for the identification of reservoir fluid properties such as bubble point pressure (P_b), solution gas-oil ratio (R_s), and oil formation-volume-factor (B_o) (**Karimnezhad et al., 2014; Salehinia et al., 2016**). Nevertheless, PVT analyses depend on experimental data that may not be readily available. In this regard, empirical correlations may be conveniently useful for estimating such parameters, which can be carried out by using field measured data such as temperature, oil gravity, and gas density, among others (**Gharbi & Elsharkawy, 2003**).

This paper aims to demonstrate the significance of applying PVT correlations in the estimation of reservoir fluid properties in the absence of laboratory data. We compared twenty empirical correlations for the determination of the solution gas-oil ratio, oil formation-volume-factor and under-saturated viscosity (μ_o) for oil samples from Brazilian pre-salt reserves originally evaluated by

Elias and Trevisan (2016). To the best of our knowledge, such a comparison has not yet been performed for pre-salt reservoir fluids and, specifically, from the Campos Basin region.

In the next section, a brief revision regarding the main correlations is presented. In Section 3, we describe the procedures for calculating P_b , B_o and μ_o , as well as the comparison approach, whereas in Section 4 we discuss the results. Finally, in Section 5, we summarize the main findings and provide some suggestions for future studies.

2. LITERATURE SURVEY

2.1 PVT properties

As previously discussed, reservoir engineers frequently are challenged to design production facilities to process crude oil so as to achieve the highest economic performance. They must, therefore, understand the phase behavior of hydrocarbons throughout the entire lifetime of the reservoir and be able to estimate fluid properties that depend on different conditions of temperature and pressure. According to **Ahmed (2010)**, these properties are determined preferably through laboratory analyses that consist in studying the volumetric behavior of live oil samples, which are, then, characterized by being subjected to several pressure level changes in a PVT cell.

The results obtained from experimental PVT tests are essential for geophysics and engineers to perform material balance calculations and reservoir simulation studies, identify potential risks, determine reserve recovery, and develop production plans (**Mansour et al., 2013; Potsch et al., 2017**). For this reason, oil samples must preserve the same characteristics as their original formation to provide reliable, high quality data, and, thus, “reduce uncertainty” and “improve investment efficiency” (**Nnabuo et al., 2014**).

However, as mentioned earlier, experimental data may not be available, especially due to the inaccessibility of samples during the early project stage when only surface tests are carried out. Hence, the lack of laboratory measurements led practitioners to use empirical correlations for estimating the volumetric behavior of reservoir

Table 1. Examples of PVT correlations^a.

Model	Parameter	Location
Katz (1942)	B_o	North America
Standing (1947)	P_b and B_o	California
Elam (1957)	P_b and B_o	Texas
Lasater (1958)	P_b	U.S.A. and Canada
Knopp and Ramsey (1960)	B_o and R_s	Venezuela
Caixerio (1976)	B_o	Brazil
Glasø (1980)	P_b and B_o	North Sea
Vazquez and Beggs (1980)	μ_{od} , P_b , B_o and R_s	Global data bank
Al-Marhoun (1985)	P_b and B_o	Middle East
Obomanu and Okpobiri (1987)	B_o and R_s	Nigeria
Abdul-Majeed and Salman (1988)	B_o	Iraq
Dokla and Osman (1992)	P_b and B_o	United Arab Emirates
Petrosky and Farshad (1993)	P_b , B_o and R_s	Gulf of Mexico
Kartoatmodjo and Schmidt (1994)	μ_{od} , C_o , P_b and B_o	Global data bank

^a μ_{od} : Dead oil viscosity. C_o : Under-saturated oil compressibility.

fluids in terms of different pressure and temperature conditions (Asadisaghendi & Tahmasebi, 2011; Karimnezhad et al., 2014). Said models have been used widely for estimating reservoir fluid properties, comparing data with laboratory results to identify associated errors and determine the quality of samples.

Numerous studies regarding the foundation of PVT correlations have been developed, among which some examples are disclosed in Table 1. We note that the majority of the correlations published so far refer to North American fields, where the oil industry started to develop since the first oil well drilling in 1859. We can also observe that bubble point pressure, solution gas-oil ratio, and oil formation-volume-factor received the most attention due to the fact that, according to Olatunji, Selamat, & Raheem (2011), “they are the most essential factors in reservoir and production computations”.

According to Ahmed (2010), the bubble point pressure refers to the pressure at which the first gas bubble is formed as the mixture is expanded isothermally. It is measured usually through laboratory tests and determined either by the

visualization of the first bubbles or graphically in a pressure to volume (PV) diagram, as shown in Figure 1. The PV diagram is obtained through Constant Composition Expansion experiments. Red and blue curves correspond to the two-phase and one-phase regions, respectively, whereas the inflection point represents the value of P_b .

The oil formation volume factor, in turn, refers to the total volume of oil required to produce one barrel under standard conditions, i.e. at 60° F and

Figure 1. Generic PV diagram.

Figure 2. Generic chart for B_o dependence on the pressure.

14.7 psia, according to the American Petroleum Institute. It can be determined as shown in Equation 1, in which V_R corresponds to the volume of oil and dissolved gas under reservoir temperature (T) and pressure (P), and V_o denotes the volume of oil under standard conditions (SC) (Mahdiani & Kooti, 2016).

$$B_o = \frac{(V_R)_{T,P}}{(V_o)^{SC}} \quad (1)$$

Plot results related to B_o data are obtained through Differential Liberation experiments, as shown in Figure 2, which illustrates how such variable is affected by the pressure. Red and blue curves refer to the two and one-phase regions, respectively, while the inflection point corresponds to the value of the formation volume factor at the bubble point (B_{ob}) (Rasouli et al., 2008). We observed that below P_b , as the pressure increases, the liquid phase becomes richer in dissolved gas, increasing V_R . On the other hand, above P_b the gas is interpreted as being completely dissolved and, therefore, B_o becomes nearly constant since it depends solely on the compressibility of the liquid phase (Pedersen et al., 2015).

Finally, the solution gas-oil ratio (R_s) is defined as the measure of the volume of dissolved gas in relation to the volume of oil produced. It can be calculated as given by Equation 2, where V_g and V_o denote the volume of dissolved gas produced and the volume of oil in the stock tank, respectively; both under standard conditions (SC) (Pedersen et al., 2015).

$$R_s = \frac{(V_g)^{SC}}{(V_o)^{SC}} \quad (2)$$

Plot results related to R_s data are also obtained through Differential Liberation experiments, as depicted in Figure 3, which shows the dependence of R_s on the pressure. Red and blue curves represent the two-phase and one-phase regions, respectively, while the inflection point refers to the value of the solution gas-oil ratio at the bubble point (R_{sb}) (Ahmed, 2010). R_s is constant above P_b since all the gas to be produced is dissolved totally in the liquid phase. Below P_b , in turn, the volume of dissolved gas – and hence R_s – increases as the pressure increases.

Although the development of empirically derived correlations allowed engineers to overcome possible issues of unavailability and unreliability associated with laboratory analyses, usually, they are not deemed as fully accurate. Various correlations have poor prediction for some points and are not flexible to be tuned globally due to differences in fluid characteristics, which vary for each location (Rafiee-Taghanaki et al., 2013). In this regard, researches started to apply computer-based techniques for predicting PVT properties due to their precision, speed and ability to process large data sets in a fast way, especially in the cases where the fluid composition is known. This is particularly true in the case of studies that deal with modeling and tuning equations of state (EOS), which have been usually carried out to describe phase behavior and fluid PVT properties

Figure 3. Generic chart for R_s dependence on the pressure.

Figure 4. Brazilian pre-salt layer.

for a wide variety of mixtures from different regions (Mansour et al., 2013; Ahmadi et al., 2019). However, according to Olatunji et al. (2011), EOS models require well-defined composition data and depend heavily on fluid characteristics and tuning procedures. To overcome such drawbacks, numerous practitioners have resorted to other computational strategies that may include, but are not limited to, artificial neural networks (Asadisaghandi & Tahmasebi, 2011; Talebi et al., 2014; Mahdiani & Kooti, 2016); support vector machine (Rafiee-Taghanaki et al., 2013; Khamis & Fattah, 2019); and fuzzy logic systems (Olatunji et al., 2011; Salehinia et al., 2016) among others. Nevertheless, said computer techniques present some shortcomings related to instability and inconsistency when handling uncertainties.

2.2 Brazilian Pre-salt

In late 90s, the Brazilian oil industry started to track down new reserves to perpetuate its production levels. With the development of new exploration technologies (e.g. 4D seismic) and after sedulous searching operations, the pre-salt layer oil was discovered in 2006-2007 by Petróleo Brasileiro S.A. (Petrobras) (Johann & Monteiro, 2016). Such milestone has impacted the Country's economic and political spheres over the past decade due to its potential to lead the petroleum industry towards a significant development.

The pre-salt layer is located in the Brazilian exclusive economic zone. It encompasses several oil reserves situated up to 300 km from the coast with different depths between 5,000 and 6,000

meters below sea level; in ultra-deep water (about 2,000 meters); and under a thick salt layer (up to 2,000 meters) (Magalhães & Domingues, 2014; Kutas, 2015), as illustrated in Figure 4.

The total oil volume in such an area is estimated at about 80 billion barrels, which could make Brazil one of the world's biggest holders of oil reserves (Magalhães & Domingues, 2014). In fact, the pre-salt region is comprised of various accumulations, among which the Campos Basin stands out as the first discovery and the main sedimentary region from the Brazilian coastline to be explored. It has a total area of approximately 100,000 square kilometers and currently accounts for 42% of the total oil production in Brazil (Pré-Sal Petróleo S.A., 2019).

The exploration of the pre-salt region is not only unprecedented but also challenging due to the unfavorable natural conditions. To overcome technical difficulties, it is a must to employ highly experienced professionals, use advanced technologies, and acquire a vast practical knowledge about the area. In this regard, scientific studies play an important role in providing the information needed to develop new strategies towards progress.

3. METHODS

Various studies regarding the development and/or evaluation of PVT correlations have been published, which evidence the significance of these data to the oil industry. However, most of these

Table 2. Range of applicability for solution gas-oil ratio correlations ^b.

Author	T (° F)	P (psi)	γ_o	γ_g
Standing (1947)	100-258	20-1425	0.72-0.96	0.59-0.95
Glasø (1980)	80-280	90-2637	0.79-0.92	0.65-1.28
Vazquez and Beggs (1980)	75-294	0-2199	0.74-0.96	0.51-1.35
Ostermann and Owolabi (1983)	122-180	515-1802	0.84-0.90	0.85-1.09
Al-Marhoun (1985)	74-240	26-1602	0.80-0.94	0.75-1.37
Obomanu and Okpobiri (1987)	123-190	73-2529	0.81-0.97	0.56-0.93
Farshad et al. (1992)	95-260	6-1645	0.80-0.95	0.66-1.7
Hasan et al. (1993)	-	-	-	-
Macary and El-Batanoney (1993)	130-290	200-1200	0.82-0.90	0.7-1.00
Petrosky and Farshad (1993)	114-288	217-1406	0.80-0.96	0.58-0.85
Kartoatmodjo and Schmidt (1994)	75-320	0-2890	0.74-0.97	0.38-1.17
Elsharkawy and Alikhan (1997)	130-250	39-1586	0.81-0.95	0.66-1.27
Levitani and Murtha (1999)	60-250	-	0.70-1.00	0.60-0.90
Al-Shammasi (2001)	74-342	32-7127	0.73-1.03	0.51-3.44
Dindoruk and Christman (2004)	117-276	926-12230	0.83-0.87	0.76-1.03
Hemmati and Kharrat (2007)	78-290	348-5156	0.79-0.94	0.52-1.42
Mazandarani and Asghari (2007)	100-250	1000-6000	0.84-0.90	0.87-1.17
Ikiensikimama and Ajienka (2012)	122-264	67-6560	0.77-0.97	0.56-1.29
Arabloo et al. (2015)	74-361	73-6629	0.75-1.03	0.52-3.44
Jarrahian et al. (2015)	68-330	83-6875	0.77-0.97	0.60-1.53

^b T: Temperature. P: Pressure. γ_o : Oil gravity. γ_g : Gas gravity.

Table 3. Range of applicability for oil formation volume factor correlations ^c.

Author	T (° F)	R_s (scf/STB)	γ_o	γ_g
Standing (1947)	100-258	20-1425	0.72-0.96	0.59-0.95
Glasø (1980)	80-280	90-2637	0.79-0.92	0.65-1.28
Vazquez and Beggs (1980)	75-294	0-2199	0.74-0.96	0.51-1.35
Al-Marhoun (1985)	74-240	26-1602	0.80-0.94	0.75-1.37
Obomanu and Okpobiri (1987)	123-190	73-2529	0.81-0.97	0.56-0.93
Abdul-Majeed and Salman (1988)	75-290	0-1664	0.74-1.00	-
Labedi (1990)	100-306	13-3533	0.79-0.86	0.70-1.47
Dokla and Osman (1992)	190-275	181-2266	0.82-0.89	0.80-1.29
Farshad et al. (1992)	95-260	6-1645	0.80-0.95	0.66-1.7
Macary and El-Batanoney (1993)	130-290	200-1200	0.82-0.90	0.7-1.00
Omar and Todd (1993)	125-280	142-1440	0.77-0.89	0.61-1.32
Petrosky and Farshad (1993)	114-288	217-1406	0.80-0.96	0.58-0.85
Kartoatmodjo and Schmidt (1994)	75-320	0-2890	0.74-0.97	0.38-1.17
Almehaideb (1997)	190-306	128-3871	0.79-0.87	0.75-1.12
Elsharkawy and Alikhan (1997)	130-250	39-1586	0.81-0.95	0.66-1.27
El-Banbi et al. (2006)	186-312	0-8280	0.74-0.85	0.67-1.14
Karimnezhad et al. (2014)	59-306	9-3299	0.77-1.03	0.62-1.53
Sulaimon (2014)	125-280	142-1440	0.77-0.89	0.04-1.32
Torabi et al. (2014)	60-140	-	0.80-1.03	-
Mahdiani and Kooti (2016)	100-280	104-1439	0.77-0.90	0.61-1.32

^c T: Temperature. R_s : Solution gas-oil ratio. γ_o : Oil gravity. γ_g : Gas gravity.

studies are based on restricted criteria that usually depend on specific properties of the given region where the data were retrieved from (Rafiee-Taghanaki et al., 2013). Therefore, in this study, we compared different correlations to assert which

ones best represent the characteristics of the Campos Basin reserves of the Brazilian pre-salt region. The models for the estimation of R_s , B_o , and μ_o studied on the present study are disclosed in Appendices A, B, and C, respectively.

Table 4. Range of applicability for undersaturated oil viscosity correlations ^d.

Author	T (° F)	P (psi)	R _s (scf/STB)	γ _o
Beal (1946)	100-220	1515-5155	-	-
Kouzel (1965)	-	407-6000	-	-
Vazquez and Beggs (1980)	75-294	141-9515	0-2199	0.74-0.96
Khan et al. (1987)	75-240	0-5000	24-1901	0.80-0.97
Abdul-Majeed et al. (1990)	-	711-7112	60-1334	0.78-0.97
Kartoatmodjo and Schmidt (1991)	-	25-6015	-	0.74-0.97
Labedi (1992)	100-306	60-6358	13-3533	0.79-0.85
De Ghetto et al. (1994)	80-342	227-15289	9-3299	0.92-1.03
Petrosky and Farshad (1995)	-	1585-10235	-	0.80-0.90
Almeida (1997)	190-306	501-4822	128-3871	0.79-0.87
Elsharkawy and Alikhan (1999)	-	1287-10000	10-3600	0.79-0.94
Dindoruk and Christman (2004)	121-276	926-12230	133-3050	0.83-0.95
Hossain et al. (2005)	-	300-3400	-	0.92-1.02
Bergman and Sutton (2006)	32-425	100-25000	0-4631	0.73-1.03
Isehunwa et al. (2006)	124-289	284-9392	43-19149	0.80-0.94
Abedini et al. (2010)	134-272	1325-3485	647-1542	0.82-0.96
Hemmati-Sarapardeh et al. (2013)	205-255	730-12500	-	0.79-0.89
Taghizadeh and Eftekhari (2014)	-	940-6015	315-1558	-
Al-Marhoun (2015)	-	0-5000	<2000	>0.80
Alqahtani et al. (2018)	-	400-3495	-	-

^d T: Temperature. P: Pressure. R_s: Solution gas-oil ratio. γ_o: Oil gravity.

Table 5. Data ranges considered in this work (according to Elias & Trevisan, 2016) ^e.

Parameter	T (° F)	P (psi)	γ _o	γ _g
R _s	68-204	711-5759.1	0.71-0.84	0.93-1.13
B _o	68-204	711-5759.1	0.71-0.84	0.93-1.13
μ _o	68-204	5759.1-9243.0	0.71-0.84	0.93-1.13

^e T: Temperature. P: Pressure. γ_o: Oil gravity. γ_g: Gas gravity.

Yet, one should note that all correlations may be applicable only depending on specific parameters. For instance, the equations evaluated in this paper can only be used for the ranges of temperature, pressure, oil and gas gravities disclosed in Tables 2, 3, and 4, respectively. This is due to the fact that such prediction models were originally developed through experimental data that were measured under those specific conditions. The same applies to Elias and Trevisan's (2016) study, which was based on the data ranges shown in Table 5. In this regard, it is expected that correlations using ranges of parameters that are different from the respective ranges considered by said authors may provide inaccurate or erroneous results. In addition to said tables, Figures 5, 6, and 7 illustrate the comparison between the validity ranges of the different correlations, and the ranges corresponding to the experimental data used by the referenced authors.

The disclosed correlations were compared to the experimental data presented by Elias and Trevisan (2016), who recombined dead oil and synthetic gas to obtain an original pre-salt live oil sample. Although the authors stated that they had analyzed oil samples found in Brazilian pre-salt reserves in the region of Campos Basin, it seems that they have opted for not providing further information regarding the respective oil fields due to confidentiality purposes. However, one may infer that the experiments were carried out using oil samples that are representative of such a region.

The qualitative comparison was carried out by means of crossplots regressions, whereas the quantitative analysis was performed through the calculation of the Average Absolute Relative Error (AARE), Root Mean Square Error (RMSE), and Standard Error of Estimate (SEE), as shown in

Equations 3, 4, and 5, respectively (Hossain et al., 2005; Rafiee-Taghanaki et al., 2013).

$$AARE = \frac{100}{n} \cdot \sum_{i=1}^n \left(\left| \frac{X_{calc} - X_{exp}}{X_{exp}} \right|_i \right) \quad (3)$$

$$RMSE = \left[\frac{1}{n} \sum_{i=1}^n (X_{calc} - X_{exp})_i^2 \right]^{0.5} \quad (4)$$

$$SEE = \left[\sum_{i=1}^n (X_{calc} - X_{exp})_i^2 / (n - v - 1) \right]^{0.5} \quad (5)$$

Where n is the number of experimental data points, X_{calc} refers to the calculated value, X_{exp} corresponds to the experimental result, and v denotes the number of independent variables.

4. RESULTS AND DISCUSSION

Statistical results comparing R_s correlations are quantitatively given in Table 6. An analysis of the results shows that **Al-Shammasi's (2001)** correlation predicted the closest values with regard to **Elias and Trevisan's (2016)** data, having an AARE of 13.7110%, a RMSE of 68.5537, and a SEE of 102.8305. **Elsharkawy and Alikhan (1997)**, **Arabloo et al. (2015)**, and **Jarrahan et al.'s (2015)** models also presented good performances. On the other hand, **Obomanu and Okpobiri's (1987)** model showed to be the most inadequate for estimating the solution gas-oil ratio for the Campos Basin oil samples, since it presented an AARE, a RMSE, and a SEE as high as 81.9856%, 764.8087, and 1147.2130, respectively. **Levitan and Murtha's (1999)** correlation also proved to be quite inaccurate, having an AARE of 55.1526%, a RMSE of 478.4374, and a SEE of 717.6561.

The accuracy of **Al-Shammasi (2001)**, **Arabloo et al. (2015)**, and **Jarrahan et al.'s (2015)** models relates to their respective data ranges, which encompass **Elias and Trevisan's (2016)**. In fact, as we can observe from Figure 5, the latter ranges of temperature, pressure, oil and gas gravities fall within the respective ranges of said correlations. Nevertheless, it is imperative to note that the ranges considered by **Obomanu and Okpobiri's (1987)** equation are quite different from the ones used by **Elias and Trevisan (2016)**. Hence, the former cannot be deemed representative of the

Figure 5. Ranges for R_s correlations: (a) Temperature; (b) Pressure; (c) Oil gravity; and (d) Gas gravity.

Campos Basin data evaluated by the latter.

The results of the B_o correlations, in turn, are shown in Table 7. We note that **Al-Marhoun's (1985)** correlation can be considered to be the most representative since it estimated the closest values to **Elias and Trevisan's (2016)** results, having

Figure 6. Ranges for B_0 correlations: (a) Temperature; (b) Oil gravity; and (c) Gas gravity.

an AARE, a RMSE, and a SEE as low as 0.4956%, 0.0116, and 0.0174, respectively.

An analysis of Table 7 points out that models presented by **Al-Marhoun (1985)**, **Petrosky and Farshad (1993)**, **Vazquez and Beggs (1980)**, **Farshad et al. (1992)**, and **Almehaideb (1997)** also showed good performances. Once more, **Obomanu and Okpobiri's (1987)** equation showed the worst prediction of performance, since it has the highest AARE (66.2463%), RMSE (1.0617), and SEE (1.5926). Other correlations that may be deemed quite inaccurate for B_0 estimation are **Macary and El-Batanoney's (1993)** (AARE of 50.3572%, RMSE of 0.7562, and SEE of 1.1343) and **Elsharkawy and Alikhan's (1997)** (AARE of 51.9248%, RMSE of 0.8703, and SEE of 1.3055).

Comparably to the analysis of R_s models, the

Figure 7. Ranges for μ_0 correlations: (a) Temperature; (b) Pressure; and (c) Oil gravity.

accuracy of **Vazquez and Beggs (1980)**, **Al-Marhoun (1985)**, **Farshad et al. (1992)**, and **Almehaideb's (1997)** models can be associated with their respective data ranges, which encompass the ranges considered by **Elias and Trevisan's (2016)** work. The ranges considered by **Obomanu and Okpobiri (1987)**, **Macary and El-Batanoney (1993)**, and **Elsharkawy and Alikhan (1997)** are significantly different than those studied by **Elias and Trevisan (2016)** and, therefore, are not representative of the latter's data.

Finally, the results of the μ_0 correlations are disclosed in Table 8. Based on these results we can state that **Beal's (1946)** model has the best performance, having an AARE, a RMSE, and a SEE as low as 0.4557%, 0.0034, and 0.0051, respectively. In addition, **Almehaideb (1997)** and **Al-Marhoun's (2015)** correlations also proved to be

Table 6. Statistical results for solution gas-oil ratio correlations.

Author	AARE	RMSE	SEE
Standing (1947)	19.6280%	124.7095	187.0642
Glasø (1980)	28.4030%	199.2099	298.8148
Vazquez and Beggs (1980)	31.9009%	267.7336	401.6003
Ostermann and Owolabi (1983)	46.3772%	468.4108	702.6162
Al-Marhoun (1985)	23.3597%	124.7855	187.1783
Obomanu and Okpobiri (1987)	81.9856%	764.8087	1147.2130
Farshad et al. (1992)	43.3295%	602.2207	903.3311
Hasan et al. (1993)	26.5825%	183.2466	274.8699
Macary and El-Batanoney (1993)	27.9560%	273.3704	410.0556
Petrosky and Farshad (1993)	26.3081%	206.8251	310.2376
Kartoatmodjo and Schmidt (1994)	27.3881%	250.7344	376.1016
Elsharkawy and Alikhan (1997)	14.5985%	82.9026	124.3540
Levitan and Murtha (1999)	55.1526%	478.4374	717.6561
Al-Shammasi (2001)	13.7110%	68.5537	102.8305
Dindoruk and Christman (2004)	26.4544%	213.1236	319.6854
Hemmati and Kharrat (2007)	19.8919%	155.5240	233.286
Mazandarani and Asghari (2007)	23.1238%	120.0571	180.0857
Ikiensikimama and Ajienka (2012)	40.3765%	469.0397	703.5595
Arabloo et al. (2015)	15.3604%	143.5444	215.3166
Jarrahian et al. (2015)	15.8614%	87.4754	131.213

Table 7. Range of applicability for oil formation volume factor correlations.

Author	AARE	RMSE	SEE
Standing (1947)	3.3561%	0.0649	0.0974
Glasø (1980)	2.7454%	0.0461	0.0692
Vazquez and Beggs (1980)	1.8727%	0.0390	0.0585
Al-Marhoun (1985)	0.4956%	0.0116	0.0174
Obomanu and Okpobiri (1987)	66.2463%	1.0617	1.5926
Abdul-Majeed and Salman (1988)	6.0462%	0.0942	0.1413
Labedi (1990)	2.5189%	0.0482	0.0723
Dokla and Osman (1992)	27.8514%	0.3964	0.5945
Farshad et al. (1992)	1.5888%	0.0240	0.0360
Macary and El-Batanoney (1993)	50.3572%	0.7562	1.1343
Omar and Todd (1993)	18.7229%	0.3017	0.4525
Petrosky and Farshad (1993)	0.8511%	0.0140	0.0210
Kartoatmodjo and Schmidt (1994)	28.3971%	0.4525	0.6788
Almehaideb (1997)	1.4679%	0.0285	0.0428
Elsharkawy and Alikhan (1997)	51.9248%	0.8703	1.3055
El-Banbi et al. (2006)	15.5575%	0.2965	0.4448
Karimnezhad et al. (2014)	2.2410%	0.0371	0.0556
Sulaimon (2014)	16.5538%	0.2645	0.3967
Torabi et al. (2014)	3.2751%	0.0522	0.0784
Mahdiani and Kooti (2016)	4.3533%	0.0761	0.1141

representative of Elias and Trevisan's (2016) data, since their statistical errors were quite low. Elsharkawy and Alikhan's (1999) equation, however, can be deemed the worst model for predicting the under-saturated oil viscosity of the Campos Basin samples due to its significant errors (AARE of 16.2215%, RMSE of 0.1468, and SEE of 0.2203). Other correlations that, due to large errors, may not be considered as representatives

for μ_o estimation are Hossain et al. (2005), Isehunwa et al. (2006), and Abedini et al.'s (2010).

One can verify that, in the case of μ_o , the performance of PVT models does not seem to be strictly dependent on their respective data ranges. Figure 7 shows that the aforementioned correlations, including the best ones, have different ranges from the ones proposed by Elias and

Table 8. Statistical results for under-saturated oil viscosity correlations.

Author	AARE	RMSE	SEE
Beal (1946)	0.4557%	0.0034	0.0051
Kouzel (1965)	2.9965%	0.0284	0.0426
Vazquez and Beggs (1980)	2.1124%	0.0194	0.0292
Khan et al. (1987)	4.1631%	0.0396	0.0594
Abdul-Majeed et al. (1990)	2.0588%	0.0184	0.0276
Kartoatmodjo and Schmidt (1991)	4.2633%	0.0403	0.0604
Labedi (1992)	2.3359%	0.0223	0.0335
De Ghetto et al. (1994)	4.0243%	0.0355	0.0533
Petrosky and Farshad (1995)	3.7108%	0.0326	0.0490
Almehaideb (1997)	0.6473%	0.0055	0.0082
Elsharkawy and Alikhan (1999)	16.2215%	0.1468	0.2203
Dindoruk and Christman (2004)	2.3349%	0.0185	0.0278
Hossain et al. (2005)	4.9473%	0.0439	0.0659
Bergman and Sutton (2006)	2.4147%	0.0188	0.0282
Isehunwa et al. (2006)	4.9385%	0.0470	0.0706
Abedini et al. (2010)	6.4906%	0.0580	0.0870
Hemmati-Sarapardeh et al. (2013)	2.6063%	0.0248	0.0372
Taghizadeh and Eftekhari (2014)	3.2091%	0.0304	0.0457
Al-Marhoun (2015)	0.6062%	0.0053	0.0079
Alqahtani et al. (2018)	3.2577%	0.0263	0.0394

Trevisan (2016). It is worth highlighting that, in this article, we aimed at comparing the behavior of generic PVT correlations when estimating fluid properties of the Campos Basin fluid samples, instead of calibrating the parameters and/or developing specific models.

It is worth pointing out that the correlations that best predicted R_s for the Campos Basin oil samples were developed originally for different fields. For instance, **Al-Shammasi (2001)**, **Arabloo et al. (2015)**, and **Jarrahian et al. (2015)** carried out their evaluation on the basis of global data sets, while **Elsharkawy and Alikhan (1997)** evaluated samples from Kuwait. In relation to B_o , **Al-Marhoun (1985)** and **Almehaideb (1997)** analyzed experimental data from the Middle East region, whereas **Petrosky and Farshad (1993)** based their analysis on samples obtained in the Gulf of Mexico area. **Farshad et al. (1992)** and **Vazquez and Beggs (1980)**, in turn, used oil samples from Colombian fields and global data sets, respectively. Finally, regarding the predictions of μ_o , **Beal's (1946)** model was based on data retrieved in the United States, while **Almehaideb (1997)** and **Al-Marhoun (2015)** developed their equations on the basis of samples from the United Arab Emirates. This corroborates **Danesh's (1998)** statement concerning the fact that petroleum properties do not depend on the reserve location itself, but instead on fluid composition and reservoir conditions. Hence, it is possible that said

references evaluated data sets with compositions similar to the ones found for **Elias and Trevisan's (2016)** samples.

The qualitative analysis for the comparison of R_s , B_o , and μ_o correlations with **Elias and Trevisan's (2016)** data was then performed through the crossplots illustrated in Figures 8, 9, and 10, respectively. Regarding the solution gas-oil ratio, most models resulted in under-predicted data, while **Farshad et al. (1992)**, **Macary and El-Batanoney (1993)**, **Ikiensikimama and Ajienka (2012)**, and **Arabloo et al. (2015)** over-estimated the values for higher pressures. In relation to the oil formation volume factor, in turn, **Abdul-Majeed and Salman (1988)**, **Kartoatmodjo and Schmidt (1994)**, **Omar and Todd (1993)**, **El-Banbi et al. (2006)**, and **Sulaimon (2014)** under-predicted the experimental data, whereas **Dokla and Osman (1992)**, **Elsharkawy and Alikhan (1997)**, **Obomanu and Okpobiri (1987)**, **Macary and El-Batanoney (1993)**, and **Mahdiani and Kooti (2016)** presented over-estimated results. Finally, with regard to under-saturated oil viscosity, **Abdul-Majeed et al. (1990)**, **Kartoatmodji and Schmidt (1991)**, **Labedi (1992)**, and **Hemmati-Sarapardeh et al. (2013)** provided under-predicted results, while **Kouzel (1965)**, **Khan et al. (1987)**, **De Ghetto et al. (1994)**, **Petrosky and Farshad (1995)**, **Elsharkawy and Alikhan (1999)**, **Hossain et al. (2005)**, **Isehunwa et al. (2006)**, and **Abedini et al.'s (2010)** models resulted in over-predicted data.

 Figure 8. Crossplots for R_s correlations (Part 1).

 Figure 8. Crossplots for R_s correlations (Part 2).

 Figure 9. Crossplots for B_o correlations (Part 1).

 Figure 9. Crossplots for B_o correlations (Part 2).

 Figure 10. Crossplots for μ_o correlations (Part 1).

 Figure 10. Crossplots for μ_o correlations (Part 2).

In accordance with the quantitative results disclosed in Tables 6, 7, and 8, we verify that **Al-Marhoun (1985)**, **Al-Shammasi (2001)** and **Beal's (1946)** correlations clearly are almost perfectly fit onto their respective equality reference lines. Therefore, they can be considered as the best models for estimating R_s , B_o , and μ_o of oils from the Campos Basin considered by **Elias and Trevisan (2016)**, respectively. Although current practices frequently use computational methods for performing calculations, simple equation forms may be preferred. In this regard, **Elsharkawy and Alikhan's (1997)** model may be selected for R_s estimation, while **Almehaideb's (1997)** correlation may be used to provide good and easy estimates for B_o . In terms of μ_o correlations, **Beal's (1946)** model may be already deemed the simplest.

It is noteworthy that most of the correlations studied in this paper presented large statistical errors because the analysis of the present work was carried out in a relatively limited range of data. Such errors could be reduced through the development of specific models for pre-salt fluids. More specifically, the development of models for oils from the Campos Basin region – which would be performed by calibrating the parameters of the respective equations. However, a more substantial amount of experimental data would be necessary.

In addition, a possible reason for obtaining such large errors may be related to the high contents of CO_2 in pre-salt reserves, which vary from about 8% (e.g. Tupi reserve, according to **Beltrão et al., 2009**) to approximately 44% (e.g. Libra field, according to **Arinelli et al., 2015**). The presence of carbon dioxide in oil reservoirs influences strongly the phase equilibria of such mixtures since CO_2 is soluble with crude oil (much more than other conventional gases), especially when the former's density increases due to compression. As discussed by **Mansour et al. (2019)**, high-pressure CO_2 dissolves in the oil, swells it, and reduces its viscosity, increasing dramatically the gas solubility and the drive energy available to reservoir production. For this particular reason, and considering environmental issues, re-injection of CO_2 has become an important strategy for enhanced oil recovery. It is therefore safe to say that PVT correlations that do not account for higher carbon dioxide compositions tend to estimate over-predicted μ_o data and under-predicted R_s values.

To the best of knowledge, most of the published contributions encompassing the presence of high CO_2 contents in oil mixtures refer to equation of state modeling (**Elias et al., 2014**), assessment of CO_2 -oil miscibility pressure (**Shokrollahi et al., 2015**), and development of specific CO_2 -dead oil viscosity and solubility models (e.g. **Welker & Dunlop, 1963**; **Simon & Graue, 1965**; **Barclay & Mishra, 2016**). In this context, future studies should focus on considering the CO_2 composition either as an independent variable in empirical correlations or as a validity range within which such models could be well-represented. Nevertheless, compositional modeling and simulation would be preferable since the accuracy of PVT correlations depend highly on the specific geographical regions from where the oil mixtures are retrieved, which may render them fairly laborious work due to the necessity of acquiring an extensive amount of field data.

5. CONCLUSIONS

Bubble point pressure, solution gas-oil ratio, and oil formation volume factor are interpreted as being the most relevant parameters for reservoir engineering and field development. Such PVT data may be acquired either from laboratory analysis or, in case of its absence, through empirical correlations.

Numerous models have been proposed for different oil types and reserves around the world. However, there is a lack of studies regarding the Brazilian pre-salt region. Specifically, since it has reshaped the Brazil's economy and has the potential of making it one of the world's biggest holders of oil reserves. Hence, we compared twenty empirical correlations for the determination of the under-saturated oil viscosity, solution gas-oil ratio, and oil formation volume factor of oil samples from the Campos Basin reserves in the Brazilian pre-salt region originally evaluated by **Elias & Trevisan (2016)**. The results obtained by the authors were tested against each correlation to determine the model with the best prediction of performance.

The qualitative comparison was performed by plotting the data in regression crossplots, whereas the quantitative analysis was carried out through the calculation of the Average Absolute Relative

Error (AARE), Root Mean Square Error (RMSE), and Standard Error of Estimate (SEE). From our results, and with regard to the Campos Basin fluids, **Al-Shammasi's (2001)** correlation proved to be the best estimation model for solution gas-oil ratio, whereas **Al-Marhoun (1985)** and **Beal's (1946)** correlations were deemed the most accurate for the prediction of oil formation volume factor and under-saturated oil viscosity, respectively.

Although the analysis of the present work was carried out in terms of a relatively limited range of data, it is believed that the purpose of providing a statistical comparison and defining the known correlations for predicting PVT properties of pre-salt fluids from the Campos Basin area could be appropriately achieved. Nevertheless, future works should aim at gathering a more substantial amount of laboratory data to develop a specific model for such fluids.

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SYMBOLS

B_o	Oil formation-volume-factor
B_{ob}	Bubble-point oil formation-volume-factor
C_o	Under-saturated oil compressibility
n	Number of experimental data points
P	Pressure
P_b	Bubble-point pressure
P_{sep}	Separator pressure
R_s	Solution gas-oil ratio
R_{sb}	Bubble-point gas-oil ratio
SC	Standard Conditions
T	Temperature
T_{sep}	Separator temperature
$(V_g)^{SC}$	Volume of gas produced under standard conditions
$(V_o)^{SC}$	Volume of oil under standard conditions

$(V_R)_{T,P}$	Volume of oil and dissolved gas under reservoir conditions
X_{calc}	Calculated value
X_{exp}	Experimental result

Greek symbols

γ_{API}	Oil API gravity
γ_g	Gas gravity
γ_o	Oil gravity
μ_o	Under-saturated oil viscosity
μ_{ob}	Bubble-point oil viscosity
μ_{od}	Dead oil viscosity

ABBREVIATIONS

AARE	Average Absolute Relative Error
API	American Petroleum Institute
CAPES	Coordenação de Aperfeiçoamento de Pessoal de Nível Superior
PVT	Pressure-Volume-Temperature
RMSE	Root Mean Square Error
SEE	Standard Error of Estimate

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APPENDIX A

Solution gas-oil ratio correlations

Standing (1947)

$$R_s = \gamma_g \left[\left(\frac{P}{18.2} + 1.4 \right) 10^{0.0125 \gamma_{API} - 0.00091(T-460)} \right]^{1.2048}$$

where γ_g = gas gravity, P = pressure (psi), γ_{API} = oil API (American Petroleum Institute) gravity, T = temperature (° F).

Glasø (1980)

$$R_s = \gamma_g \left\{ \left[\frac{\gamma_{API}^{0.989}}{(T-460)^{0.172}} \right] 10^{2.8869 - [14.1811 - 3.3093 \log_{10}(P)]^{0.5}} \right\}^{1.2255}$$

where γ_g = gas gravity, P = pressure (psi), γ_{API} = oil API gravity, T = temperature (° R).

Vazquez and Beggs (1980)

$$R_s = C_1 \gamma_g \left[1 + 5.912 \cdot 10^{-5} \gamma_{API} (T_{sep} - 460) \log_{10} \left(\frac{P_{sep}}{114.7} \right) \right] \times P^{C_2} \exp \left[C_3 \left(\frac{\gamma_{API}}{T} \right) \right]$$

where $C_1 = 0.0362$, $C_2 = 1.0937$, $C_3 = 25.724$, γ_g = gas gravity, P_{sep} = separator pressure (psia), P = pressure (psia), γ_{API} = oil API gravity, T = temperature (° R), T_{sep} = separator temperature (° R).

Ostermann and Owolabi (1983)

$$55 + 0.8643 \left[\left(\frac{R_s}{\gamma_g} \right)^{1.255} \frac{T^{0.172}}{\gamma_{API}^{0.178}} \right] - P = 0$$

where γ_g = gas gravity, P = pressure (psi), γ_{API} = oil API gravity, T = temperature (° R).

Al-Marhoun (1985)

$$R_s = (185.843208 \gamma_g^{1.87784} \gamma_o^{-3.1437} T^{-1.32657} P)^{1.39844}$$

where γ_g = gas gravity, P = pressure (psi), γ_o = oil gravity, T = temperature (° R).

Obomanu and Okpobiri (1987)

$$R_s = \frac{0.03008 P^{0.927} \gamma_g^{2.15} \gamma_{API}^{1.27}}{10^{0.811} T^{0.497}}$$

where γ_g = gas gravity, P = pressure (psi), γ_{API} = oil API gravity, T = temperature (° F).

Farshad et al. (1992)

$$10^{0.3058 + 1.9013 \log(X) - 0.26 [\log(X)]^2} - P = 0$$

$$X = \gamma_g^{-1.378} R_s^{1.053} 10^{0.00069(T-460) - 0.0208 \gamma_{API}}$$

where γ_g = gas gravity, P = pressure (psi), γ_{API} = oil API gravity, T = temperature (° R).

Hasan et al. (1993)

$$R_s = \left[(0.0546P - 2.2) \frac{\gamma_g}{10^{0.00091T - 0.0125 \gamma_{API}}} \right]^{1.205}$$

where γ_g = gas gravity, P = pressure (psi), γ_{API} = oil API gravity, T = temperature (° F).

Macary and El-Batanoney (1993)

$$R_s = \left[0.0049 \frac{P}{\exp(0.00077T - 0.0097 \gamma_{API} - 0.4003 \gamma_g)} + 4.7927 \right]^{1.9606}$$

where γ_g = gas gravity, P = pressure (psi), γ_{API} = oil API gravity, T = temperature (° F).

Petrosky and Farshad (1993)

$$R_s = \left[\left(\frac{P}{112.727} + 12.34 \right) \gamma_g^{0.8439} 10^{7.916 \cdot 10^{-4} \gamma_{API}^{1.541} - 4.561 \cdot 10^{-5} (T-460)^{1.3911}} \right]^{1.73184}$$

where γ_g = gas gravity, P = pressure (psi), γ_{API} = oil API gravity, T = temperature ($^{\circ}$ R).

Kartoatmodjo and Schmidt (1994)

$$R_s = P^{1.001402} 0.05958 \gamma_g^{0.7972} 10^{\frac{13.1405 \gamma_{API}}{T}}$$

where γ_g = gas gravity, P = pressure (psi), γ_{API} = oil API gravity, T = temperature ($^{\circ}$ R).

Elsharkawy and Alikhan (1997)

$$R_s = \gamma_g P^{1.18026} 10^{-1.2179 + 0.4636 \left(\frac{\gamma_{API}}{T} \right)}$$

where γ_g = gas gravity, P = pressure (psi), γ_{API} = oil API gravity, T = temperature ($^{\circ}$ R).

Leviton and Murtha (1999)

$$R_s = \gamma_g \left[805.887 P \gamma_o^{-1.5} T^{-1.5} \right]^{1.1765}$$

where γ_g = gas gravity, P = pressure (psi), γ_o = oil gravity, T = temperature ($^{\circ}$ R).

Al-Shammasi (2001)

$$R_s = \left[\exp(1.841408 \gamma_g \gamma_o) P \gamma_o^{-5.527215} \gamma_g^{-0.783716} T^{-0.783716} \right]^{1.276}$$

where γ_g = gas gravity, P = pressure (psi), γ_o = oil gravity, T = temperature ($^{\circ}$ R).

Dindoruk and Christman (2004)

$$R_s = \left[\left(\frac{P}{3.35975497} + 28.10133245 \right) \gamma_g^{1.57905016} 10^X \right]^{0.92813144}$$

$$X = \frac{4.86996 \cdot 10^{-6} \gamma_{API}^{5.730982539} + 9.9251 \cdot 10^{-3} (T - 460)^{1.776179364}}{\left(44.2500268 + \frac{2 \gamma_{API}^{2.702889206}}{P^{0.744335673}} \right)^2}$$

where γ_g = gas gravity, P = pressure (psi), γ_{API} = oil API gravity, T = temperature ($^{\circ}$ R).

Hemmati and Kharrat (2007)

$$R_s = \left[0.1769 \gamma_g^{1.0674} \gamma_o^{-5.0956} T^{-0.1394} P \right]^{1.0857}$$

where γ_g = gas gravity, P = pressure (psi), γ_o = oil gravity, T = temperature ($^{\circ}$ F).

Mazandarani and Asghari (2007)

$$R_s = 994.3718 \gamma_g^{2.113367} P^{1.4556} \gamma_o^{-5.48944} T^{-1.90488}$$

where γ_g = gas gravity, P = pressure (psi), γ_o = oil gravity, T = temperature ($^{\circ}$ R).

Ikiensikimama and Aijenka (2012)

$$R_s = \left[(0.059155P + 1.40573) 10^{0.0128746 \gamma_{API} - 0.000913115T} \right]^{1.23153}$$

where P = pressure (psi), γ_{API} = oil API gravity, T = temperature ($^{\circ}$ F).

Arabloo et al. (2015)

$$R_s = \frac{5000 \left[6.102089 e^{-9} \left(\frac{\gamma_{API}}{\gamma_{API} + 50} \right) P \left(\frac{1}{\gamma_g + 5} \right)^{-5.651436} \left(\frac{T}{T + 500} \right)^{-0.095371} \right]^{1.091273}}{1 - \left[6.102089 e^{-9} \left(\frac{\gamma_{API}}{\gamma_{API} + 50} \right) P \left(\frac{1}{\gamma_g + 5} \right)^{-5.651436} \left(\frac{T}{T + 500} \right)^{-0.095371} \right]^{1.091273}}$$

where γ_g = gas gravity, P = pressure (psi), γ_{API} = oil API gravity, T = temperature ($^{\circ}$ F).

Jarrahan et al. (2015)

$$R_s = \left[\frac{33.382 P \gamma_g^{0.448067}}{\gamma_o^{3.32023} \exp \left(\frac{-0.542446 \gamma_g}{\gamma_o} \right) T^{1.074756}} \right]^{1.21255}$$

where γ_g = gas gravity, P = pressure (psi), γ_{API} = oil API gravity, T = temperature ($^{\circ}$ R).

APPENDIX B

Oil formation-volume-factor correlations

Standing (1947)

$$B_o = 0.9759 + 0.00012 \left[R_s \left(\frac{\gamma_g}{\gamma_o} \right)^{0.5} + 1.25T \right]^{1.2}$$

where γ_g = gas gravity, γ_o = oil gravity, T = temperature ($^{\circ}$ F), R_s = gas-oil ratio (scf/STB).

Glasø (1980)

$$B_o = 1 + 10^X$$

$$X = -6.58511 + 2.91329 \log \left(R_s \left(\frac{\gamma_g}{\gamma_o} \right)^{0.526} + 0.968T \right) - 0.27683 \log \left(R_s \left(\frac{\gamma_g}{\gamma_o} \right)^{0.526} + 0.968T \right)^2$$

where γ_g = gas gravity, γ_o = oil gravity, T = temperature ($^{\circ}$ F), R_s = gas-oil ratio (scf/STB).

Vazquez and Beggs (1980)

$$B_o = 1 + C_1 R_s + (T - 520) \left(\frac{\gamma_{API}}{\gamma_g \left[1 + 5.921 \cdot 10^{-5} (\gamma_{API}) (T_{sep} - 460) \log \left(\frac{P_{sep}}{114.7} \right) \right]} \right) (C_2 + C_3 R_s)$$

where $C_1 = 4.68 \times 10^{-4}$, $C_2 = 1.75 \times 10^{-5}$, $C_3 = -1.81 \times 10^{-8}$, γ_g = gas gravity, P_{sep} = separator pressure (psia), γ_{API} = oil API gravity, T = temperature ($^{\circ}$ R), T_{sep} = separator temperature ($^{\circ}$ R), R_s = gas-oil ratio (scf/STB).

Al-Marhoun (1985)

$$B_o = 0.497069 + 0.000862693T + 0.00182594X + 0.0000031809X^2$$

$$X = R_s^{0.74239} \gamma_g^{0.323294} \gamma_o^{-1.20204}$$

where γ_g = gas gravity, γ_o = oil gravity, T = temperature ($^{\circ}$ R), R_s = gas-oil ratio (scf/STB).

Obomanu and Okpobiri (1987)

$$B_o = 1.0232 + 0.0001065 \left[R_s \left(\frac{\gamma_g}{\gamma_o} + 1.8T - 460 \right) \right]^{0.79}$$

where γ_g = gas gravity, γ_o = oil gravity, T = temperature (K), R_s = gas-oil ratio (scf/STB).

Abdul-Majeed and Salman (1988)

$$B_o = 0.563427 + 7.73 \cdot 10^{-4} T + 4.8141 \cdot 10^{-5} X - 6.8987 \cdot 10^{-10} X^2$$

$$X = R_s^{1.2} \gamma_g^{-0.147} \gamma_o^{-5.222}$$

where γ_g = gas gravity, γ_o = oil gravity, T = temperature ($^{\circ}$ R), R_s = gas-oil ratio (scf/STB).

Labedi (1990)

$$B_o = 0.9897 + 0.0001364 \left[R_s \left(\frac{\gamma_g}{\gamma_o} \right)^{0.5} + 1.25T \right]^{1.175}$$

where γ_g = gas gravity, γ_o = oil gravity, T = temperature ($^{\circ}$ F), R_s = gas-oil ratio (scf/STB).

Dokla and Osman (1992)

$$B_o = 0.408345 + 1.56667 \cdot 10^{-3} T + 1.39775 \cdot 10^{-3} X - 380525 \cdot 10^{-6} X^2$$

$$X = R_s^{0.773572} \gamma_g^{0.40402} \gamma_o^{-0.882605}$$

where γ_g = gas gravity, γ_o = oil gravity, T = temperature ($^{\circ}$ R), R_s = gas-oil ratio (scf/STB).

Farshad et al. (1992)

$$B_o = 1 + 10^{-2.6541 + 0.557 \log(X) + 0.333 \log(X)^2}$$

$$X = R_s^{0.5956} \gamma_g^{0.2369} \gamma_o^{-1.3282} + 0.0976T$$

where γ_g = gas gravity, γ_o = oil gravity, T = temperature ($^{\circ}$ F), R_s = gas-oil ratio (scf/STB).

Macary and El-Batanoney (1993)

$$B_o = (1.0031 + 0.0008T) \cdot \exp(0.0004R_s + 0.0006 \frac{\gamma_o}{\gamma_g})$$

where γ_g = gas gravity, γ_o = oil gravity, T = temperature ($^{\circ}$ R), R_s = gas-oil ratio (scf/STB).

Omar and Todd (1993)

$$B_o = 0.972 + 0.0001472 \left(R_s \left(\frac{\gamma_g}{\gamma_o} \right)^{0.5} + 1.125T^X \right)$$

$$X = 1.166 + 0.000762 \frac{\gamma_o}{\gamma_g} - 0.0399 \gamma_g$$

where γ_g = gas gravity, γ_o = oil gravity, T = temperature ($^{\circ}$ F), R_s = gas-oil ratio (scf/STB).

Petrosky and Farshad (1993)

$$B_o = 1.0113 + 7.2046 \cdot 10^{-5} \left[R_s^{0.3738} \left(\frac{\gamma_g^{0.2914}}{\gamma_o^{0.6265}} \right) + 0.24626T^{0.5371} \right]^{3.0936}$$

where γ_g = gas gravity, γ_o = oil gravity, T = temperature ($^{\circ}$ F), R_s = gas-oil ratio (scf/STB).

Kartoatmodjo and Schmidt (1994)

$$B_o = 0.98496 + 0.0001 (R_s^{0.755} \gamma_g^{0.25} \gamma_o^{-1.5} + 0.45T)$$

where γ_g = gas gravity, γ_o = oil gravity, T = temperature ($^{\circ}$ F), R_s = gas-oil ratio (scf/STB).

Almehaideb (1997)

$$B_o = 1.122 + 0.00000141 R_s \frac{T}{\gamma_o^2}$$

where γ_o = oil gravity, T = temperature ($^{\circ}$ F), R_s = gas-oil ratio (scf/STB).

Elsharkawy and Alikhan (1997)

$$B_o = 1 + 4.0428 \cdot 10^{-4} R_s + 6.3802 \cdot 10^{-4} (T - 60) + 7.8 \cdot 10^{-6} \left[\frac{R_s (T - 60) \gamma_g}{\gamma_o} \right]$$

where γ_g = gas gravity, γ_o = oil gravity, T = temperature ($^{\circ}$ F), R_s = gas-oil ratio (scf/STB).

El-Banbi et al. (2006)

$$B_o = 47.23 - 8.833 \left[R_s \left(\frac{\gamma_g}{\gamma_o} \right)^{0.5} + 1.325T \right]^{-0.0092} - 36.6$$

where γ_g = gas gravity, γ_o = oil gravity, T = temperature ($^{\circ}$ F), R_s = gas-oil ratio (scf/STB).

Karimnezhad et al. (2014)

$$B_o = \left[1.166 \left(R_s \frac{\gamma_o}{\gamma_g} \right)^{-0.03} + 4.4 \cdot 10^{-6} (R_s T)^{0.894} \right]^X$$

$$X = T^{-0.044} \gamma_o^{-1.52} \gamma_g^{0.161}$$

where γ_g = gas gravity, γ_o = oil gravity, T = temperature ($^{\circ}$ R), R_s = gas-oil ratio (scf/STB).

Sulaimon (2014)

$$B_o = 0.0000009 R_s \left(\frac{\gamma_g}{\gamma_o} + T \right) + 1.0367$$

where γ_g = gas gravity, γ_o = oil gravity, T = temperature ($^{\circ}$ F), R_s = gas-oil ratio (scf/STB).

Torabi et al. (2014)

$$B_o = 0.733 + 0.000014P + 0.00842\gamma_{API} + 0.00053R_s$$

where P = pressure (psi), γ_{API} = oil API gravity, T = temperature ($^{\circ}$ F), R_s = gas-oil ratio (scf/STB).

Mahdiani and Kooti (2016)

$$B_o = 1.1292 - 0.67343 \frac{R_s}{(T\gamma_g)^2} + 8.3272 \cdot 10^{-6} T^2 + 0.00053679 R_s - 0.0019306T$$

where γ_g = gas gravity, T = temperature ($^{\circ}$ F), R_s = gas-oil ratio (scf/STB).

APPENDIX C

Under-saturated oil viscosity correlations

Beal (1946)

$$\mu_o = \mu_{ob} + 0.001(P - P_b) \left(0.024\mu_{ob}^{1.6} + 0.038\mu_{ob}^{0.56} \right)$$

where μ_{ob} = bubble-point oil viscosity (cP), P = pressure (psi), P_b = bubble-point pressure (psi).

Kouzel (1965)

$$\mu_o = \mu_{ob} \exp \left[\left(5.50318 \cdot 10^{-5} + 3.77163 \cdot 10^{-5} \mu_{ob}^{0.278} \right) (P - P_b) \right]$$

where μ_{ob} = bubble-point oil viscosity (cP), P = pressure (psi), P_b = bubble-point pressure (psi).

Vazquez and Beggs (1980)

$$\mu_o = \mu_{ob} (P / P_b)^X$$

$$X = 2.6P^{1.187} \exp \left[-8.95 \cdot 10^{-5} P - 11.513 \right]$$

where μ_{ob} = bubble-point oil viscosity (cP), P = pressure (psi), P_b = bubble-point pressure (psi).

Khan et al. (1987)

$$\mu_o = \mu_{ob} \cdot \exp \left[9.6 \cdot 10^{-5} (P - P_b) \right]$$

where μ_{ob} = bubble-point oil viscosity (cP), P = pressure (psi), P_b = bubble-point pressure (psi).

Abdul-Majeed et al. (1990)

$$\mu_o = \mu_{ob} + 1000 \cdot 10^{X - 5.2106 + 1.11 \log [6.894757(P - P_b)]}$$

$$X = 1.9311 - 0.89941 \ln(R_s) - 0.001194\gamma_{API}^2 +$$

$$+ 0.0092545\gamma_{API} \ln(R_s)$$

where μ_{ob} = bubble-point oil viscosity (cP), P = pressure (psi), P_b = bubble-point pressure (psi), γ_{API} = oil API gravity, R_s = gas-oil ratio (scf/STB).

Kartoatmodjo and Schmidt (1991)

$$\mu_o = 1.00081\mu_{ob} + 1.127 \cdot 10^{-3} (P - P_b) \left(-6.517 \cdot 10^{-3} \mu_{ob}^{1.8148} + 0.038\mu_{ob}^{1.59} \right)$$

where μ_{ob} = bubble-point oil viscosity (cP), P = pressure (psi), P_b = bubble-point pressure (psi).

Labedi (1992)

$$\mu_o = \mu_{ob} - \left[\frac{10^{-2.488} \mu_{od}^{0.9036} P_b^{0.6151}}{10^{0.01976 \gamma_{API}}} \right] \left[1 - \left(\frac{P}{P_b} \right) \right]$$

$$\mu_{od} = \frac{10^{9.224}}{\gamma_{API}^{4.7013} T^{0.6739}}$$

where μ_{ob} = bubble-point oil viscosity (cP), μ_{od} = dead oil viscosity (cP), P = pressure (psi), P_b = bubble-point pressure (psi), γ_{API} = oil API gravity, T = Temperature ($^{\circ}$ F).

De Ghetto et al. (1994)

$$\mu_o = \mu_{ob} - \left[\left(1 - \frac{P}{P_b} \right) \left(\frac{10^{-3.8055} \mu_{od}^{1.4131} P_b^{0.6957}}{10^{-0.00288 \gamma_{API}}} \right) \right]$$

where μ_{ob} = bubble-point oil viscosity (cP), μ_{od} = dead oil viscosity (cP), P = pressure (psi), P_b = bubble-point pressure (psi), γ_{API} = oil API gravity.

Petrosky and Farshad (1995)

$$\mu_o = \mu_{ob} + 1.3449 \cdot 10^{-3} (P - P_b) \cdot 10^X$$

$$X = -1.0146 + 1.3322 \log(\mu_{ob}) - 0.4876 (\log(\mu_{ob}))^2 - 1.15036 (\log(\mu_{ob}))^3$$

where μ_{ob} = bubble-point oil viscosity (cP), P = pressure (psi), P_b = bubble-point pressure (psi).

Almehaideb (1997)

$$\mu_o = \mu_{ob} \left(\frac{P}{P_b} \right)^{0.134819 + 1.94345 \cdot 10^{-4} R_s - 1.93106 \cdot 10^{-9} R_s^2}$$

where μ_{ob} = bubble-point oil viscosity (cP), P = pressure (psi), P_b = bubble-point pressure (psi), R_s = gas-oil ratio (scf/STB).

Elsharkawy and Alikhan (1999)

$$\mu_o = \mu_{ob} + \frac{10^{-2.0771} (P - P_b) \mu_{od}^{1.19279}}{\mu_{ob}^{0.40712} P_b^{0.7941}}$$

where μ_{ob} = bubble-point oil viscosity (cP), μ_{od} = dead oil viscosity (cP), P = pressure (psi), P_b = bubble-point pressure (psi).

Dindoruk and Christman (2004)

$$\mu_o = \mu_{ob} + 0.00006334 (P - P_b) \cdot 10^X$$

$$X = C_1 + C_2 \log(\mu_{ob}) - C_3 \log(R_s) + C_4 \mu_{ob} \log(R_s) - C_5 (P - P_b)$$

where $C_1 = 0.776644115$, $C_2 = 0.987658646$, $C_3 = 0.190564677$, $C_4 = 9.147711 \times 10^{-3}$, $C_5 = 1.9111 \times 10^{-5}$, μ_{ob} = bubble-point oil viscosity (cP), P = pressure (psi), P_b = bubble-point pressure (psi), R_s = gas-oil ratio (scf/STB).

Hossain et al. (2005)

$$\mu_o = \mu_{ob} + 0.004481 (P - P_b) \times (P - P_b) (0.555955 \mu_{ob}^{1.068099} - 0.527737 \mu_{ob}^{1.063547})$$

where μ_{ob} = bubble-point oil viscosity (cP), P = pressure (psi), P_b = bubble-point pressure (psi).

Bergman and Sutton (2006)

$$\mu_o = \mu_{ob} \exp \left[\alpha (P - P_b)^\beta \right]$$

$$\beta = 2.24623 \cdot 10^{-2} \ln(\mu_{ob}) + 0.873204$$

$$\alpha = 6.5698 \cdot 10^{-7} \ln(\mu_{ob})^2 - 1.48211 \cdot 10^{-5} \ln(\mu_{ob}) + 2.27877 \cdot 10^{-4}$$

where μ_{ob} = bubble-point oil viscosity (cP), P = pressure (psi), P_b = bubble-point pressure (psi).

Isehunwa et al. (2006)

$$\mu_o = \mu_{ob} \exp(1.02 \cdot 10^{-4} (P - P_b))$$

where μ_{ob} = bubble-point oil viscosity (cP), P = pressure (psi), P_b = bubble-point pressure (psi).

Abedini et al. (2010)

$$\mu_o = \mu_{ob} + 0.001 (P - P_b) X$$

$$X = C_1 \mu_{ob}^{1.45198} + C_2 \mu_{ob}^{0.35997} - C_3 \mu_{ob}^{0.86389} - C_4 P_b^{-0.41866} - (C_5 P_b^{-0.29981} - C_6 P_b^{-0.1946} - C_7 P_b^{-0.31339})$$

where $C_1 = 0.05601$, $C_2 = 0.47557$, $C_3 = 0.2257$, $C_4 = 0.29598$, $C_5 = 0.07734$, $C_6 = 0.42436$, $C_7 = 1.64149$,

μ_{ob} = bubble-point oil viscosity (cP), P = pressure (psi), P_b = bubble-point pressure (psi).

Hemmati-Sarapardeh et al. (2013)

$$\mu_o = \mu_{ob} + (P - P_b) \left[C_1 \left(\frac{\mu_{ob}}{P_b} \right)^{0.3895556} + C_2 \left(\frac{\mu_{ob}}{P_b} \right)^{1.226398} + C_3 \mu_{ob}^{0.001254195 P_b + 0.3026506} \right]$$

where $C_1 = 7.376096 \times 10^{-4}$, $C_2 = 0.2444663$, $C_3 = 5.60643 \times 10^{-4}$, μ_{ob} = bubble-point oil viscosity (cP), P = pressure (psi), P_b = bubble-point pressure (psi).

Taghizadeh and Eftekhari (2014)

$$\mu_o = \mu_{ob} \exp[8.85 \cdot 10^{-5} (P - P_b)]$$

where μ_{ob} = bubble-point oil viscosity (cP), P = pressure (psi), P_b = bubble-point pressure (psi).

Al-Marhoun (2015)

$$\mu_o = \exp(\ln \mu_{ob} + 0.151292 \cdot 10^{-3} \gamma_{ob}^2 (P - P_b))$$

$$\gamma_{ob} = (\gamma_o + 2.18 \cdot 10^{-4} R_s \gamma_g) / B_{ob}$$

where μ_{ob} = bubble-point oil viscosity (cP), P = pressure (psi), P_b = bubble-point pressure (psi), B_{ob} = bubble-point oil formation-volume-factor (bbl/STB), R_s = gas-oil ratio (scf/STB).

Alqahtani et al. (2018)

$$\mu_o = \mu_{ob} + 0.3055 \left[0.1323 \left[\left(\frac{P}{P_b} \right) X \right] - \mu_{ob} \right] - 0.0086 \left[-0.0099 \right]$$

$$X = \left(1.0529 \left[0.1317 \left(\frac{P}{P_b} \right) (\mu_{ob} - 1.7892) \right] [\mu_{ob} - 3.4466] + 0.3579 + \mu_{ob} \right)$$

where μ_{ob} = bubble-point oil viscosity (cP), P = pressure (psi), P_b = bubble-point pressure (psi).