

Article

Rheological Characterization and Viscosity Correlation for a 9.5 °API Extra-Heavy Crude Oil of the Southern Gulf of Mexico

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Abstract

The rheological behavior of a 9.5 °API extra-heavy dead crude oil produced in the southern Gulf of Mexico is experimentally investigated over the temperature range $30\text{ °C} \leq T \leq 100\text{ °C}$. Steady-shear measurements are used to characterize the stress–strain–rate response and apparent viscosity under controlled laboratory conditions representative of surface transport. Statistical analyses show that the oil exhibits a Bingham plastic behavior at 30 °C, transitions to a Herschel–Bulkley-type response at 50 °C, and displays a predominantly dilatant behavior at 100 °C. Existing dead oil viscosity correlations commonly used in field applications are evaluated against the experimental data and are found to systematically underpredict the viscosity by approximately one order of magnitude within the studied temperature range. Motivated by the observed exponential dependence of viscosity on temperature, a crude-specific viscosity–temperature correlation is proposed for this specific crude oil. The new correlation provides a significantly improved representation of the experimental data and leads to substantially more accurate pressure drop predictions in a representative pipeline transport scenario. The results highlight the importance of crude-oil-specific rheological characterization and viscosity modeling for reliable flow assurance analyses involving extra-heavy crude oils.

Keywords: extra-heavy crude oil; non-Newtonian rheology; viscosity correlation; temperature dependence; flow assurance

1. Introduction

Heavy and extra-heavy crude oils represent nearly 47% of total production in the southern Gulf of Mexico, making this type of hydrocarbon particularly important for the oil and gas companies operating in Mexico [1]. A proper characterization of these oil types is key to the development of other oil fields in the region. Such characterizations must explicitly account for the rheological behavior of the local crude oils over the temperature and shear-rate ranges encountered during production, transportation, and surface handling. The information thus obtained leads to the creation of adequate correlations to estimate flow parameters in different production scenarios.

The challenges concerning the production and transportation of heavy and extra-heavy oils are well known. These are observed to behave as non-Newtonian, viscoelastic fluids at low temperatures and as Newtonian fluids at high enough temperatures [2]. The apparent viscosity of heavy and extra-heavy dead oils exhibits a strong nonlinear



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dependence on temperature. Several correlations, such as those proposed by Vazquez and Beggs [3], Glaso [4], Al-Marhoun [5], Standing [6], and Kartoatmodjo and Schmidt [7], are commonly used in practice to predict this property as a function of API gravity and temperature. However, these correlations are valid for crude oils whose compositions are not necessarily representative of those considered here. In the present case, depending on the chemical composition and other factors (e.g., diagenetic aspects and maturation of kerogen), the viscosity values of the oils of interest may lie in the range from 0.1 to 10 Pa·s (100 to 10,000 cP).

On the other hand, the heavy and extra-heavy oils produced in different fields are subjected to specific physical and chemical characteristics, including pressure, temperature, molecular composition, and water content. Furthermore, high levels of salt concentrations (in connate water), asphaltenes, and acidity caused by the presence of bitter gases, such as hydrogen sulfides and carbon dioxide, make the viscosities of their respective dead oils differ by up to an order of magnitude for a given API gravity and temperature. Hossain et al. [8] developed a correlation that works in the range from -0.15 to 92.85 °C (31.73 to 199.13 °F). It was obtained from a data set provided by Chevron, based on the compositional analysis of 10 heavy oil samples, from which multiple viscosity data points were generated, including measurements with dissolved gas and dead oil conditions.

The authors compared the solubility relation, the bubbly pressure, and the viscosities with the correlations proposed by Naseri et al. [9] and Egbogah et al. [10]. Later, Hossain et al. [8] introduced a statistical improvement by determining the average percentage relative error (APRE) and absolute average percentage error (AAPRE) estimates, as well as Pearson's correlation coefficient R .

Regarding the viscosity of Mexican heavy and extra-heavy crude oils, Mendoza de la Cruz et al. [11] performed several tests on five samples, while taking into account their respective SARA analyses.

The proposed correlation produced valid viscosity predictions within the interval 0.01 to 7.47 Pa·s (10.9 to 7476.7 cP), for temperatures between 34.85 and 123.95 °C (81.77 to 255.11 °F) and densities between 11.5 and 19.4 °API at a constant pressure of 0.1 MPa (14.5 psi). A subsequent comparison indicated that most of the available correlations underestimated the viscosity of these heavy and extra-heavy dead oils [11]. Similarly, the classical correlations by Beal [12] and Bennisson [13] were observed to underpredict the viscosity behavior of these crude types.

For the crude types produced in Kuwait, Alomair et al. [14] considered the relevance of the API gravity on the prediction of the dead oil viscosity. A total of 492 data points were analyzed to determine the viscosity within the interval ranging from 1.784×10^{-3} to 4.867 Pa·s (1.784 to 4867 cP). It can readily be seen in Figure 1 that the dependence of μ on T becomes stronger for lower API gravity values.

More recently, Merola et al. [15] investigated the viscosity behavior of heavy dead oils with high asphaltene content. Three samples (from the same stock) with volume fractions of 77.98%, 78.77%, and 78.08% were considered. Interestingly, it was concluded that the microstructural organization of the heavy molecular fractions may play a key role in the rheological response of the fluid. This implies the need for adequate correlations for each type of crude oil.

According to the previous account, the existing correlations are not well suited to yield acceptable viscosity values for some heavy and extra-heavy oils currently being produced in the southern Gulf of Mexico. This calls for type-specific correlations for those cases that are not covered in the study by Mendoza de la Cruz et al. [11]. Therefore, in this work, we set out to consider the rheology of a typical crude oil from this region, in order to produce an ad hoc correlation for its viscosity. The resulting correlation could prove useful

to the field operators concerned with the flow assurance and handling problems associated with crudes of this kind. This would be especially important in those cases where logistic operations, such as pipeline transportation and storage, are a major concern.

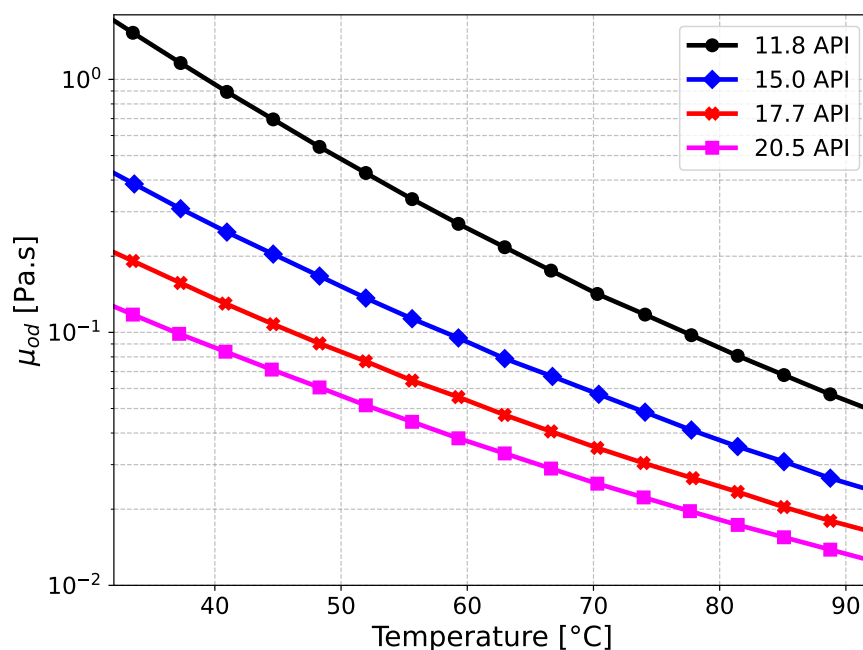


Figure 1. Effect of the API density on the viscosity of Kuwaiti dead oils (reproduced with the data from Alomair et al. [14]).

2. Materials and Methods

An extra-heavy oil with a 9.5 °API gravity was experimentally evaluated. Its composition at reservoir conditions was determined in accordance with the ASTM-D2007 standard. The corresponding tests were carried out with an Agilent Technologies FID-GC2 gas–liquid chromatograph. Figure 2 shows the resulting composition analysis for this type of crude. The salient feature is the extremely elevated content of asphaltenes and resins, as underlined by the rather large mol fraction of the C7+ compounds. These heavy molecular fractions are known to promote strong intermolecular interactions and microstructural organization, which are often associated with yield stress, shear-dependent viscosity, and temperature-sensitive rheological transitions [16,17].

In addition, the PVT profile for the crude sample at reservoir conditions is summarized in Table 1. These values correspond to an available data set that was obtained (in past tests) in compliance with the ASTM-D4052, ASTM-D3700, and ASTM-445-04e2 standards. We note that the gas–oil ratio (GOR) value is quite low for the given conditions. Thus, this oil may be considered to be essentially free of gas once it flows through the surface production facilities.

Table 1. PVT properties for the 9.5 °API crude sample at reservoir conditions.

Property (in Reservoir)	Value	Unit
Pressure	25.42	MPa
Temperature	122.8	°C
Gas–oil ratio	27.1	std m ³ /stock-tank m ³
Oil formation volume factor	1.15	res m ³ /stock-tank m ³
Density	908.8	kg/m ³
Isothermal compressibility	1.014	MPa ^{−1}

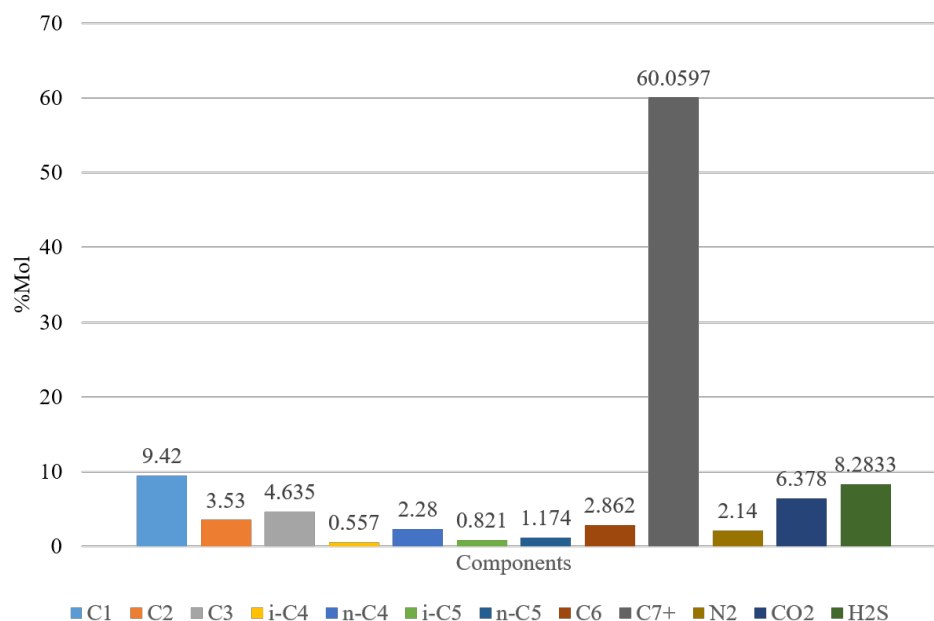


Figure 2. Composition of the representative 9.5 °API crude type produced in the southern Gulf of Mexico.

Accordingly, all other measurements were carried out for dead oil samples with a Stabinger SVM 3000 Anton Paar viscometer and a MCR Anton Paar rheometer. Nine samples of this crude type were considered: two were tested at 30 °C, four were tested at 50 °C, and the remaining three were tested at 100 °C (86, 122, and 212 °F). The lower temperature bound was dictated by the operational constraints of the equipment. Evidence suggests that high-molecular-weight components play a key role in the rheological behavior of heavy and extra-heavy crudes at different temperatures (e.g., [11]). Therefore, we collected 3152 measurements points using the rheometer to determine the stress–strain rate relationship, as well as the apparent viscosity, within the temperature interval of interest.

3. Results

Figure 3a–c illustrate the measured stress–strain rate dependence on the temperature for the different samples. Clearly, temperature exerts a dominant influence on the σ – $\dot{\gamma}$ relationship, modifying both the magnitude of the shear stress and the functional form of the stress–strain-rate response. Notice that the stress (σ) drops approximately one order-of-magnitude at 100 °C, for any given shear rate ($\dot{\gamma}$), as compared with the other two temperatures. It must also be pointed out that the trends are nonlinear and that the $\sigma = \sigma(\dot{\gamma}(T))$ functional relationship cannot be represented uniquely by a particular rheological model. In this section, we will discuss the possible descriptions in terms of the statistical characterization of the measurements.

Similarly, Figure 4a–c illustrate the (apparent) viscosity–strain rate dependence on temperature, i.e., $\mu = \mu(\dot{\gamma}(T))$. This crude type is evidently non-Newtonian, because its viscosity exhibits a strong, nonlinear dependence on the temperature. The behavior of the viscosity in the high-temperature regime is particularly interesting: the viscosity has a global minimum at $\dot{\gamma} \approx 60 \text{ s}^{-1}$. Such highly nonlinear effects are consistent with temperature-induced rearrangements of the internal microstructure, leading to changes in the dominant dissipation mechanisms at elevated temperatures. In contrast, the intermediate and lower temperature cases seem to decrease monotonously (on average) throughout the entire strain rate interval. However, important fluctuations are observed to occur as the temperature is lowered (e.g., Figure 4a).

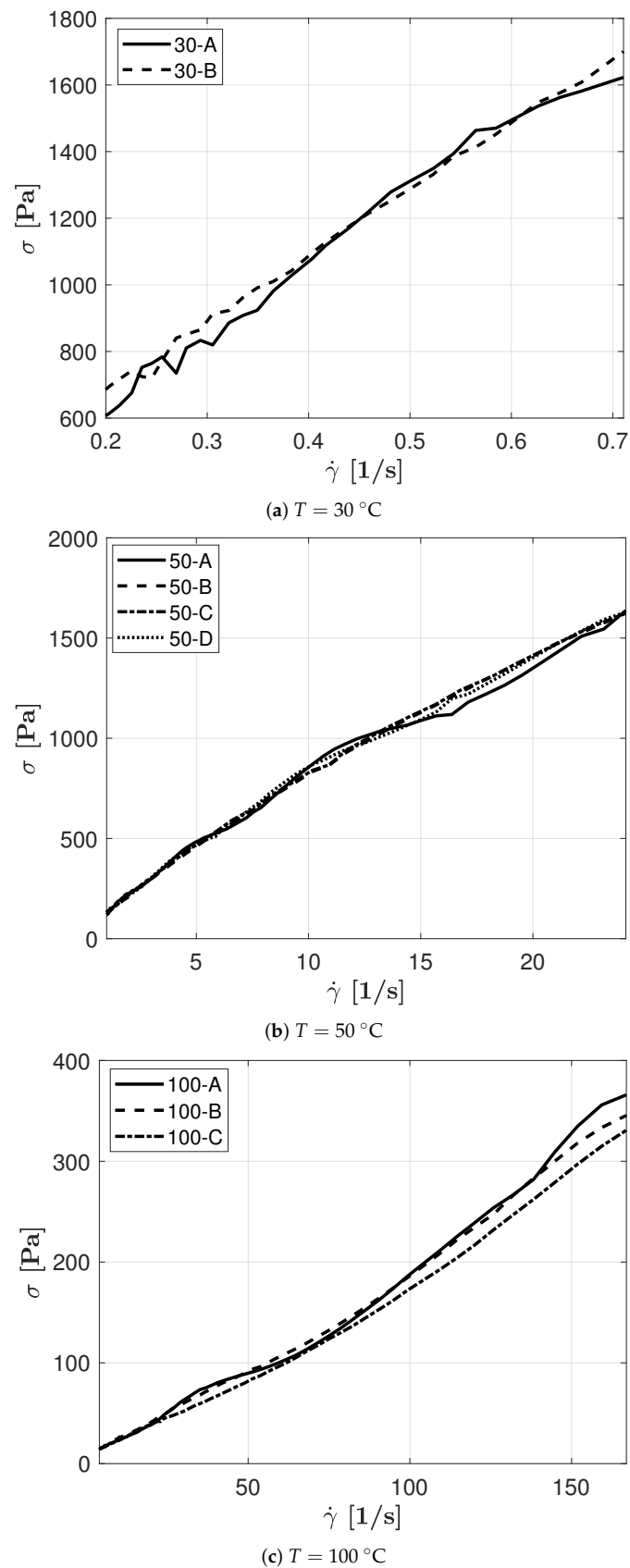


Figure 3. Shear stress, σ , as a function of the shear rate, $\dot{\gamma}$, and the temperature T . At each temperature, the curves labeled A, B, C, or D represent measurements from different samples of the same crude oil.

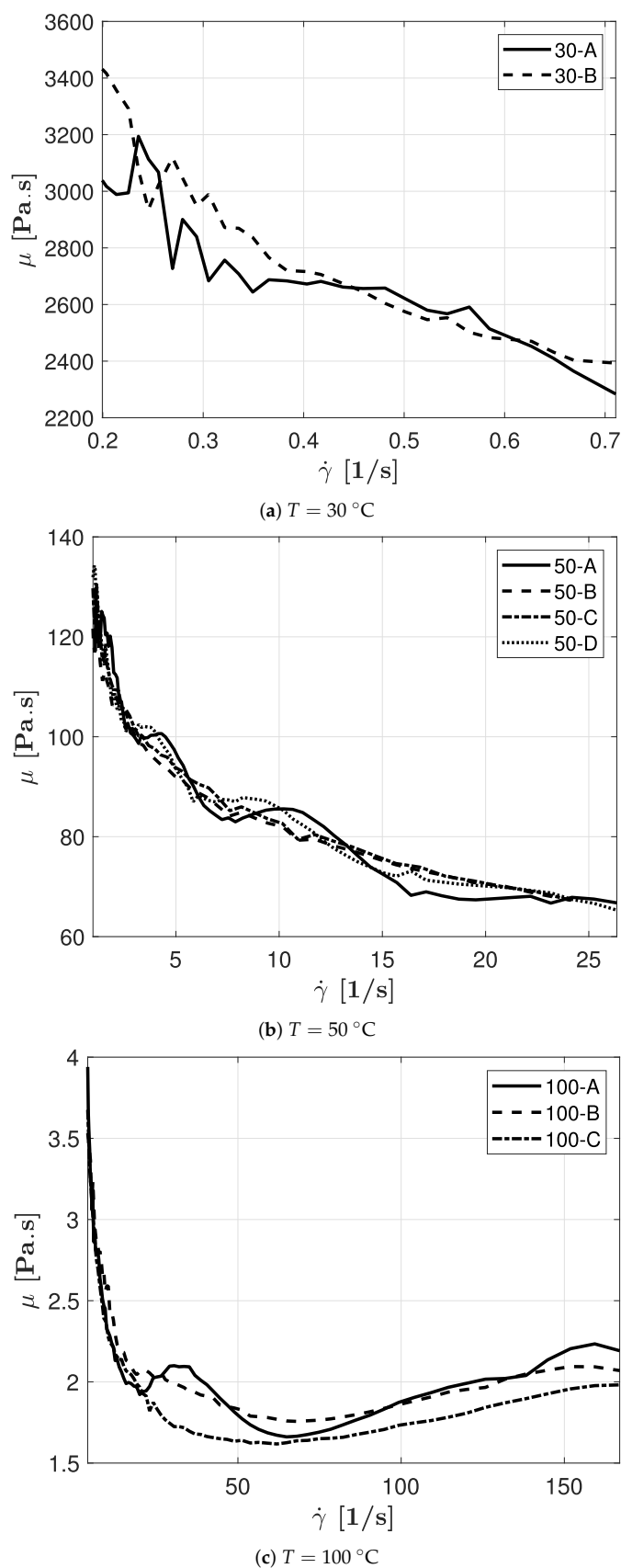


Figure 4. Apparent viscosity, μ , as a function of shear rate, $\dot{\gamma}$, and temperature T . At each temperature, the curves labeled A, B, C, or D represent measurements from different samples of the same crude oil.

The σ vs. $\dot{\gamma}$ relationship was statistically analyzed to characterize the extra-heavy crude oil under consideration. As a first step in this analysis, we averaged the results for all

the samples tested at a given temperature. Then, the following parameters were evaluated: (a) the average percentage relative error (APRE), (b) the absolute average percentage error (AAPRE), (c) the standard deviation (STD), and (d) the Pearson's correlation coefficient (R). Their respective numerical values are computed with

$$\text{APRE} = \frac{100}{n} \sum_{i=1}^n \left(\frac{y_i - y_{\text{exp}}}{y_{\text{exp}}} \right), \quad (1)$$

$$\text{AAPRE} = \frac{100}{n} \sum_{i=1}^n \left| \frac{y_i - y_{\text{exp}}}{y_{\text{exp}}} \right|, \quad (2)$$

$$\text{STD} = \sqrt{\frac{\sum_{i=1}^n (y_i - \bar{y})^2}{n - 1}}, \quad (3)$$

and

$$R = \frac{\sum_{i=1}^n (x_i - \bar{x})(y_i - \bar{y})}{\sqrt{\sum_{i=1}^n (x_i - \bar{x})^2} \sqrt{\sum_{i=1}^n (y_i - \bar{y})^2}} \quad (4)$$

Here, $\bar{x} = n^{-1} \sum_i x_i$ and $\bar{y} = n^{-1} \sum_i y_i$ represent the averages of the data points. Note also that y_i and y_{exp} refer to the predicted and experimental values, respectively. Table 2 summarizes the resulting values for the three temperatures. Since these parameters provide a measure for the statistical agreement between model predictions and experimental data, the numbers in boldface are indicative of the model best fitting the data set in each case.

Table 2. Statistical comparison of rheological models at different temperatures. Bold values indicate the statistically dominant model for each temperature and metric.

Metric	Temperature (°C)	Bingham Plastic	Herschel–Bulkley	Dilatant
APRE	30	0.0014	−0.0195	0.0246
	50	0.1456	−0.0594	0.1391
	100	0.0405	0.5602	0.0033
AAPRE	30	0.0014	0.0709	0.0126
	50	0.1761	0.0852	0.1726
	100	0.0405	0.6272	0.0023
STD	30	0.9821	94.3532	86.4712
	50	48.3722	45.2484	47.4755
	100	1.5689	36.3835	0.0001
Pearson's R	30	0.9999	0.9609	0.9798
	50	0.9867	0.9908	0.9872
	100	0.9996	0.5682	0.9999

According to these results, the oil behaves as a Bingham plastic at 30 °C, while at 50 and 100 °C, it behaves more like a Herschel–Bulkley and a dilatant fluid, respectively. Therefore, for the Bingham plastic, we consider

$$\sigma = \sigma_0 + \mu_{od}(\dot{\gamma})\dot{\gamma} \quad (5)$$

where σ_0 is the yield shear-stress and $\mu_{od}(\dot{\gamma})$ is a dynamic viscosity that depends on the strain rate. Although the classical Bingham plastic model assumes a constant plastic viscosity, the present formulation allows μ_{od} to be interpreted as an effective viscosity evaluated at a characteristic shear rate. This approach is adopted to facilitate comparison with experimental data while preserving the essential yield-stress behavior observed at

low temperatures. This effective formulation is adopted for engineering consistency and does not imply a departure from yield-stress-dominated behavior.

Analogously, for temperatures $T \sim 50$ °C, the applicable Herschel–Bulkley model reads

$$\sigma = \sigma_0 + \kappa \dot{\gamma}^\eta \quad (6)$$

Again, σ_0 represents a finite yield stress, κ is the consistency index, and η is the so-called flow index.

When the oil is at temperatures $T \sim 100$ °C, the fluid's dilatant behavior is described by

$$\sigma = \mu_{od}(\dot{\gamma}) \dot{\gamma} \quad (7)$$

The fitted parameters corresponding to the statistically dominant rheological model at each investigated temperature are summarized in Table 3. No rheological parameters are reported for the dilatant regime at 100 °C, since the flow behavior is adequately characterized by a shear-dependent apparent viscosity without yield stress, as reflected in the statistical analysis.

Table 3. Fitted rheological parameters corresponding to the statistically dominant rheological model at each temperature for the 9.5 °API crude oil.

T (°C)	Model	σ_0 (Pa)	κ (Pa·s $^\eta$)	η
30	Bingham plastic	0.986	–	–
50	Herschel–Bulkley	1.556	107.26	0.881
100	Dilatant	–	–	–

The temperature dependence enters implicitly through $\mu_{od} = \mu_{od}(\dot{\gamma}(T))$. The above models appear to fit the experimental data reasonably well, as can be seen in Figure 5a–c. The relative error bars are plotted in red, to highlight those regions of the $\dot{\gamma}$ interval where the samples show a more complex behavior. One may readily notice that the largest fluctuations are produced with lower $\dot{\gamma}$ values. This behavior is especially exacerbated at lower temperatures. By way of contrast, other models would utterly fail to describe the correct $\sigma = \sigma(\dot{\gamma}(T))$ relationship everywhere.

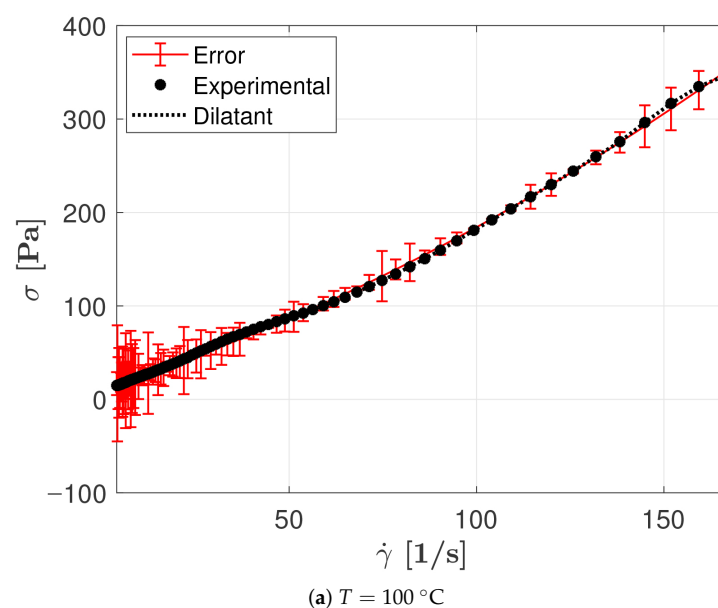


Figure 5. Cont.

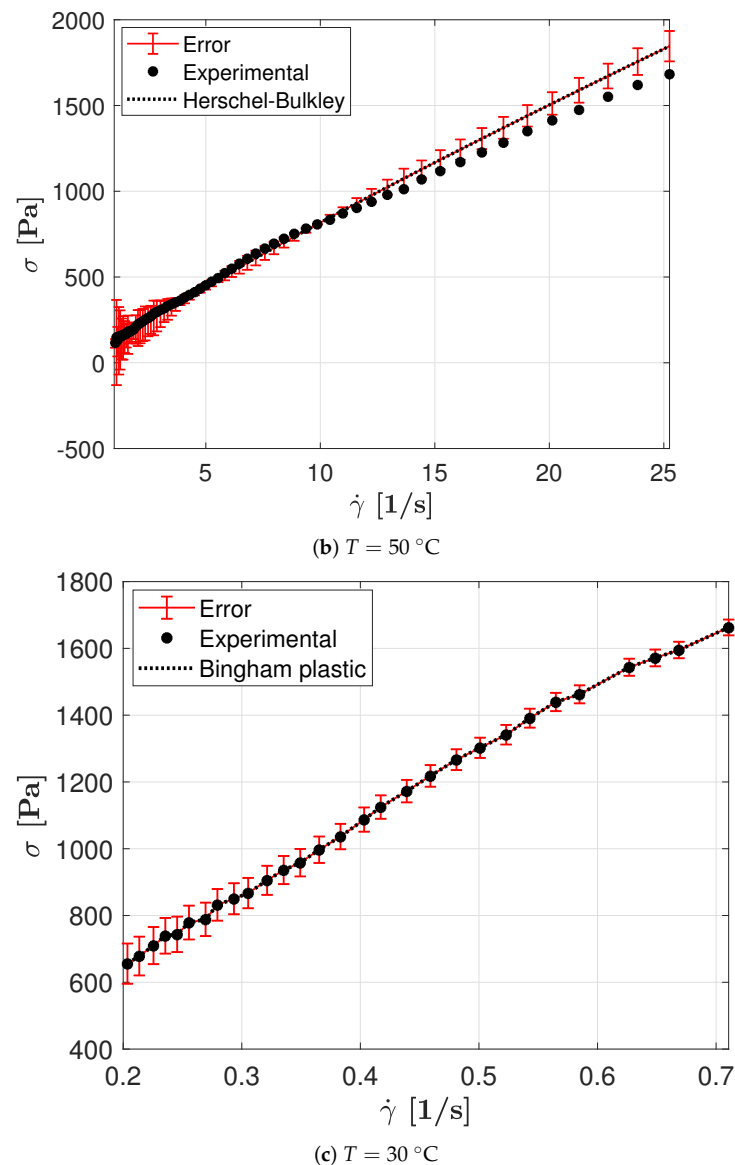


Figure 5. Nature of the $\sigma = \sigma(\dot{\gamma}(T))$ relationship for the 9.5° API crude produced in the southern Gulf of Mexico.

4. Discussion

In view of the foregoing results, a proper assessment of the predictions obtained with the state-of-the-art models for extra-heavy crude oils becomes a necessity. To this end, we consider the previously mentioned existing correlations by Hossain et al. [8], Mendoza de la Cruz et al. [11], and Alomair et al. [14] within the experimental temperature interval $30\text{ }^{\circ}\text{C} \leq T \leq 100\text{ }^{\circ}\text{C}$. Figure 6 shows the results. It is quite evident that all models underpredict the viscosity by nearly one order of magnitude within the stated temperature interval.

Interestingly, the experimental data exhibit a (nearly perfect) exponential law dependency on the temperature. In contrast, the available correlations predict a markedly different (power law) functional relationship $\mu_{od} = \mu_{od}(T)$. This suggests the convenience of using of an exponential relationship to adequately represent this type of crude oil.

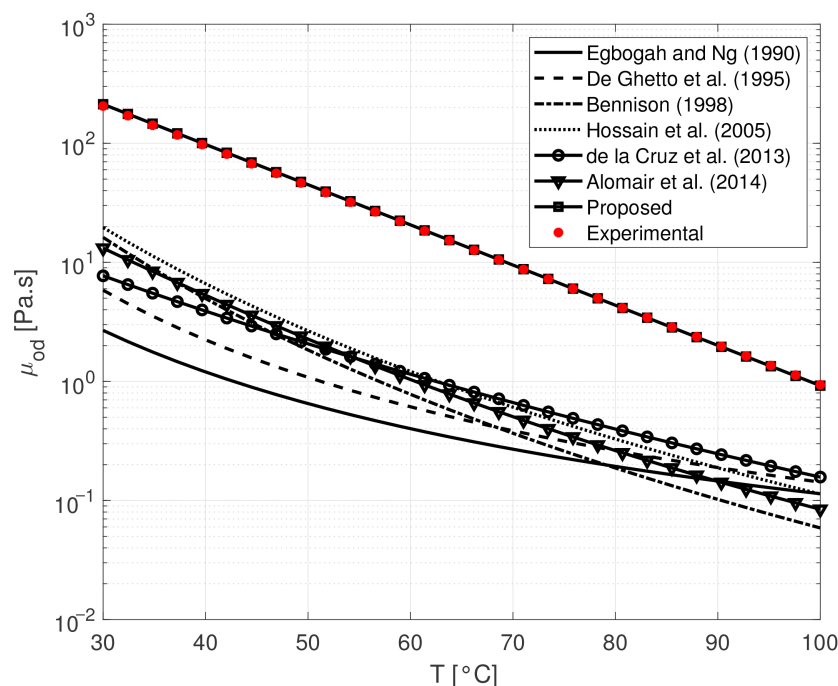


Figure 6. Comparison of the experimental results (red dots) with the predictions produced by the well-known and most widely used correlations for heavy and extra-heavy crude oils. The proposed correlation is seen to perform better throughout the entire range, as it fits the experimental data for this particular 9.5 °API crude type well [8,10,11,13,14,18].

4.1. Correlation for the Viscosity

An ad hoc correlation for the viscosity $\mu_{od} = \mu_{od}(T)$ was developed on the basis of the previous statistical characterization. In a sense, the correlation may be regarded as an extension of the model reported by Mendoza de la Cruz et al. [11]. For the analyzed 9.5 °API oil, the correlation best fitting the experimental data within the temperature interval $30\text{ }^{\circ}\text{C} \leq T \leq 100\text{ }^{\circ}\text{C}$ is an exponential. It may be written as follows:

$$\ln(\mu_{od}) = \ln(\mu_0) - a(T - T_0) \quad (8)$$

where μ_0 is the reference viscosity at $T_0 = 30\text{ }^{\circ}\text{C}$, and a is a reciprocal temperature slope.

The regression constants were obtained by means of a least squares method, whereby

$$\ln(\mu_{od}) = \overline{\ln \mu_0} - a(\overline{T} - T_0) \quad (9)$$

and

$$a = \frac{n \sum T_i \ln(\mu_{od})_i - \sum T_i \sum \ln(\mu_{od})_i}{n \sum T_i^2 - (\sum T_i)^2} \quad (10)$$

As before, the symbol $\overline{(\cdot)}$ in the above expression denotes an averaged quantity. The numerical values of the regression coefficients are $\mu_0 = 205.43\text{ Pa}\cdot\text{s}$ and $a = 0.0777\text{ }^{\circ}\text{C}^{-1}$, with T in $^{\circ}\text{C}$.

Physically, the proposed correlation implies that the rate of viscosity reduction with temperature is proportional to the instantaneous viscosity, which is consistent with thermally activated flow mechanisms in highly viscous, structured fluids. The proposed model is compared in Figure 6 with the experimental data, as well as with the correlations by Egbogah et al. [10], De Ghetto et al. [18], Bennison [13], Hossain et al. [8], Mendoza de la Cruz et al. [11], and Alomair et al. [14].

For the crude oil type under consideration, we observe that the proposed correlation performs significantly better than any of the other available correlations within the temper-

ature interval of interest. As in the case of the correlation by Mendoza de la Cruz et al. [11], the present model is valid only for the 9.5 °API, dead crude oils produced in the southern Gulf of Mexico.

With a proper value of $\mu_{od} = \mu_{od}(\dot{\gamma}(T))$, it is then possible to determine the stresses produced on the transportation system, and hence the pressure drops, for a given rheological behavior. It suffices to introduce the obtained μ_{od} value in the model corresponding to a particular temperature range (i.e., Equations (5) to (7)).

4.2. Effects on the Pressure Drop in Pipes

In practical field operations, inaccuracies in the estimation of crude oil viscosity may lead to substantial errors in the predicted pressure drop along pipelines, directly affecting flow assurance, pumping requirements, equipment sizing, and operational reliability. To illustrate this effect for the extra-heavy crude oil analyzed in this work, a representative pipeline transport scenario was numerically simulated using the rheological characterization and viscosity correlation developed in the previous sections.

The elevation profile, axial discretization, and ambient temperature distribution adopted for the simulated pipeline are summarized in Table 4. The total pipeline length is approximately 2.85 km, with elevation variations representative of shallow-water flowlines including both exposed and buried sections. Lower ambient temperatures (on the order of 20 °C) correspond to buried segments in soil or seabed sediments, while higher temperatures represent exposed or shallow-water portions.

Table 4. Geometric and thermal profile of the representative pipeline used for the pressure drop simulations.

Section	z_1 (m)	z_2 (m)	x_1 (m)	x_2 (m)	T_∞ (°C)
1	0.00	−0.20	0.00	176.00	34.7
2	−0.20	0.51	176.00	485.00	34.8
3	0.51	0.85	485.00	712.00	33.8
4	0.85	0.70	712.00	1068.00	29.9
5	0.70	0.70	1068.00	1272.88	20.8
6	0.70	0.60	1272.88	1674.08	20.8
7	0.60	−0.15	1674.08	2032.11	21.8
8	−0.15	−0.30	2032.11	2267.61	21.8
9	−0.30	0.30	2267.61	2575.63	23.8
10	0.30	0.41	2575.63	2852.99	30.5

The simulated system corresponds to single-phase oil flow under steady-state conditions. The pipeline inner diameter was $D = 0.235$ m (10-inch nominal diameter with a wall thickness of 0.375 in), and the imposed flow rate was selected to yield a mean velocity of approximately 1 m s^{-1} , consistent with typical operating conditions for heavy and extra-heavy crude oil pipelines. The oil was assumed to enter the pipeline at a temperature of approximately 30 °C.

The pressure drop along the pipeline was computed by solving a one-dimensional steady momentum balance coupled with an axial energy balance. At each axial segment, fluid properties were updated based on the local temperature, and the cumulative pressure drop was obtained by accounting for both frictional and hydrostatic contributions.

Experimental rheological results presented in this work indicate that, at temperatures close to 30 °C, the crude oil exhibits a clear Bingham plastic behavior characterized by a finite yield shear stress σ_0 , as described by Equation (5). For simplicity and to isolate the impact of viscosity underestimation, the Bingham plastic model was applied along the entire pipeline, using temperature-dependent viscosity values. This choice provides a

conservative estimate of pressure losses while maintaining consistency with the dominant low-temperature rheological behavior.

Under steady, fully developed, laminar flow conditions in a circular pipe, the frictional pressure gradient for a Bingham plastic fluid may be written as

$$\frac{dP}{dx} = \frac{32\mu_{od}U}{D^2} \left(1 + \frac{Bn}{3}\right), \quad (11)$$

where U is the mean flow velocity, D is the pipe inner diameter, and μ_{od} denotes the dynamic viscosity evaluated at a characteristic shear rate representative of the flow.

The Bingham number is defined as

$$Bn = \frac{\sigma_0 D}{\mu_{od} U}. \quad (12)$$

The hydrostatic contribution to the pressure variation was evaluated as

$$\left(\frac{dP}{dx}\right)_{\text{elev}} = \rho g \frac{dz}{dx}, \quad (13)$$

where ρ is the oil density, g is the gravitational acceleration, and z is the local elevation.

The axial temperature evolution was obtained from a steady one-dimensional energy balance:

$$\frac{dT}{dx} = -\frac{q'}{\dot{m}c_p}, \quad (14)$$

where $\dot{m}$ is the mass flow rate, c_p is the specific heat capacity, and q' is the heat transfer rate per unit length. Heat losses to the environment were modeled using a thermal resistance network accounting for internal convection, pipe wall conduction, and external convection:

$$q' = \frac{T - T_\infty}{R_{\text{tot}}}, \quad (15)$$

with

$$R_{\text{tot}} = \frac{1}{h_i \pi D} + \frac{\ln(D_o/D)}{2\pi k_w} + \frac{1}{h_o \pi D_o}. \quad (16)$$

At the low Reynolds numbers encountered in this regime, the internal convective heat transfer coefficient was evaluated using a constant Nusselt number corresponding to fully developed laminar flow with constant wall temperature,

$$Nu = 3.66, \quad h_i = \frac{Nu k}{D}, \quad (17)$$

where k is the thermal conductivity of the oil.

To assess the impact of viscosity modeling on pressure drop predictions, the above procedure was repeated using several widely employed viscosity correlations for heavy and extra-heavy crude oils available in the literature (cf. Table 5). In these cases, the oil was treated as a Newtonian fluid, consistent with the assumptions underlying the original correlations, and the frictional pressure drop was computed using the classical Darcy–Weisbach formulation with laminar or turbulent friction factors depending on the local Reynolds number.

Figure 7 compares the cumulative pressure drop along the pipeline obtained using the proposed viscosity correlation coupled with a Bingham plastic rheology against those predicted using literature viscosity correlations assuming Newtonian behavior. The results clearly show that the use of standard or non-oil-specific viscosity correlations leads to a

severe underestimation of the pressure drop, exceeding one order of magnitude over the pipeline length considered. Such discrepancies would translate directly into major errors in pump sizing, energy consumption estimates, and flow assurance assessments, highlighting the critical importance of using viscosity correlations and rheological models consistent with the actual behavior of extra-heavy crude oils.

Table 5. Dead oil viscosity correlations in their original published forms. The correlations are reproduced exactly as published; unit conversions are required before implementation in SI units.

Correlation	Published Form
Egbogah & Ng [10] ^{a,b,c}	$\log_{10}[\log_{10}(\mu_{od} + 1)] = 1.8653 - 0.0250867 API - 0.56441 \log_{10}(T_f)$
De Ghetto et al. [18] ^{a,b,c}	$\log_{10}[\log_{10}(\mu_{od} + 1)] = 2.06492 - 0.0179 API - 0.70226 \log_{10}(T_g)$
Bennison [13] ^{a,b,d}	$\mu_{od} = 10^{(0.10231 API^2 - 3.9464 API + 46.5037)} T^{(-0.04542 API^2 + 1.70405 API - 19.18)}$
Hossain et al. [8] ^{a,b,d}	$\mu_{od} = 10^{(-0.71523 API + 22.13766)} T^{(0.269024 API - 8.268047)}$
de la Cruz et al. [11] ^{a,b,d}	$\mu_{od} = e^{\left(\frac{a}{API^3}\right)} - 1, \quad a = 39053.9772 T^{-1.3683}$
Alomair et al. [14] ^{a,b,d}	$\ln(\ln(\mu)) = 0.07547 + \frac{5.76588}{\ln(API)} - 0.00101 (1.8T + 32) - \ln(1.8T + 32)$

^a In all correlations, μ_{od} (or μ) denotes the dead oil viscosity, typically expressed in cP. ^b API is the API gravity of the crude oil. ^c T_f and T_g denote temperature in degrees Fahrenheit (°F), as originally used by Egbogah and Ng (1990) [10] and De Ghetto et al. (1995) [18], respectively. ^d T denotes temperature in degrees Rankine (°R) in the correlations by Bennison (1998) [13] and Hossain et al. (2005) [8], and temperature in degrees Celsius (°C) in the correlations by de la Cruz et al. (2013) [11] and Alomair et al. (2014) [14].

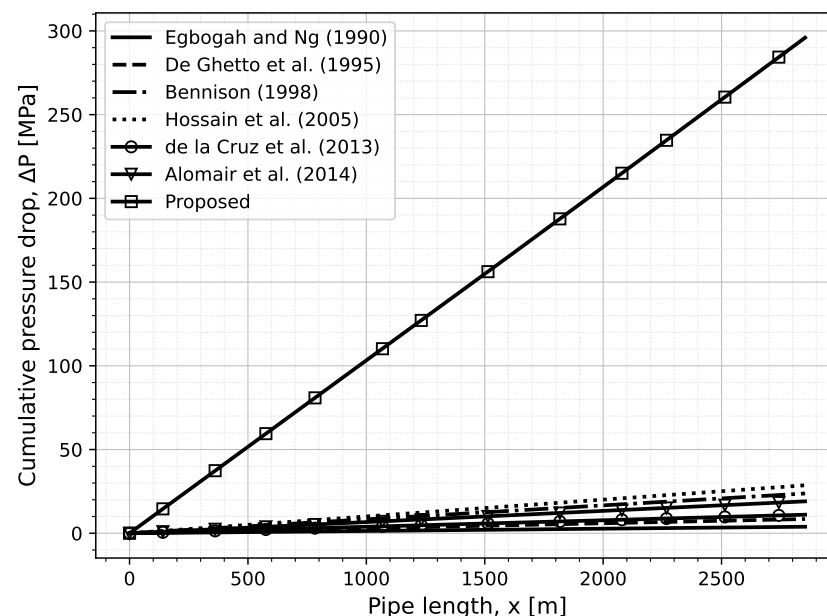


Figure 7. Comparison of cumulative pressure drop along the pipeline predicted using different viscosity correlations [8,10,11,13,14,18].

5. Conclusions

The present work delivers key insights into the rheological and viscosity behaviour of a 9.5 °API extra-heavy dead crude oil from the southern Gulf of Mexico:

1. The oil exhibits a strongly non-Newtonian response across the temperature range 30–100 °C:
 - Bingham plastic behaviour at 30 °C, with a finite yield stress;
 - Herschel–Bulkley model best fits the response at 50 °C;
 - Predominantly dilatant behaviour at 100 °C.

2. Existing viscosity correlations underpredict the oil's viscosity by nearly an order of magnitude, attributed to its unique physicochemical characteristics (low API gravity, high asphaltene content).
3. Experimental results reveal an exponential viscosity–temperature relationship, diverging from the power law trends in existing models.
4. A new exponential viscosity–temperature correlation was developed, offering accurate estimates (0.9–205 Pa·s) and significantly improved pressure drop predictions for flow assurance and pipeline design.

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Abbreviations

Nomenclature

a	Regression constant in viscosity correlation	—
$^{\circ}\text{API}$	API gravity of the crude oil	—
$\dot{\gamma}$	Shear rate	s^{-1}
η	Flow index (Herschel–Bulkley model)	—
κ	Consistency index (Herschel–Bulkley model)	$\text{Pa}\cdot\text{s}^{\eta}$
n	Number of data points	—
μ_{od}	Dead oil dynamic viscosity	$\text{Pa}\cdot\text{s}$ (1 $\text{Pa}\cdot\text{s}$ = 1000 cP)
μ	Generic dynamic viscosity (legacy correlations)	$\text{Pa}\cdot\text{s}$
T	Temperature	$^{\circ}\text{C}$
σ	Shear stress	Pa
σ_0	Yield shear stress	Pa
y_i	Predicted value of a measured quantity	—
y_{exp}	Experimental value of a measured quantity	—

Subscripts and superscripts

i	Index of data point
0	Reference value
od	Dead oil
exp	Experimental value
$pred$	Predicted value

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