SPE 163342

Heavy Oil Viscosity and Density Prediction at Normal and Elevated Temperatures

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This paper was prepared for presentation at the SPE Kuwait International Petroleum Conference and Exhibition held in Kuwait City, Kuwait, 10–12 December 2012.

Abstract

Viscosity and Density are important physical parameter of crude oil, closely related with the whole processes of production and transportation, and are very essential properties to the process design and petroleum industries simulation. As viscosity increases, a conventional measurement becomes progressively less accurate and more difficult to obtain. According to the literature survey, most published correlations that are used to predict density and viscosity of heavy crude oil are limited to certain temperatures, API values, and viscosity ranges. The objective of present work is to propose accurate models that can successfully predict two important fluid properties, viscosity and density covering a wide range of temperatures, API, and viscosities. Viscosity and density of more than 30 heavy oil samples of different API gravities collected from different oilfield were measured at temperature range 15^{o}C to 160^{o}C (60^{o}F to 320^{o}F), and the results were used to ensure the capability of proposed and published correlations to predict the experimental viscosity and density data. The proposed correlation can be summarized in two stages. The first step was to predict the heavy oil density from API and temperature for different crudes. The predicted values of the densities were used in the second step to develop the viscosity correlation model. A comparison of the predicted and actual viscosities data, concluded that the proposed model has successfully predict all data with average relative errors of less than 12% and with the correlation coefficient R^2 of 0.97, and 0.92 at normal and high temperatures respectively. Meanwhile, the results of most of the available models has an average relative error above 40%, with R^2 values between 0.19 to 0.95. These comparisons were made as a quality control to confirm the reliability of the proposed model to predict density and viscosity values of heavy crudes when compared with other models.

***Keywords*:** Heavy Crude Oil, Viscosity, elevated Temperature

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1.0 Introduction

The recent developments in oil upgrading technologies caused a growth in the demand of heavy oil in the international market. Usually when the crude oil does not flow easily, it is called heavy oil. Classifying crude as heavy oil is based on many factors (e.g molecular weight, viscosity, density, or API gravity). The most common definition to heavy crude oil is the crude with API gravity lower than 20^o. Knowledge of oil viscosity is essential to many areas in the petroleum industry including; reservoir and fluid production to upgrading and transporting produce fluids. Viscosity also plays a vital role in Enhanced Oil Recovery (EOR) methods. Viscosity data in the petroleum industry are usually obtained at reservoir temperature, which is a constant value. However, viscosity data at temperatures other than reservoir are estimated from empirical correlations, where laboratory data becomes unavailable. Sampling and viscosity measurement methods are the main reasons for inaccessibility of these data at other temperatures. Sampling of high viscosity oil is a major obstacle. It needs to be correlated to estimate this values in reservoir hence it is very time consuming and costly to measure viscosity at reservoir condition[1], and can determine the success or failure of a given EOR scheme. Consequently viscosity is an important parameter for numerical simulation and determining the economics of EOR project. The viscosity of crude oil varies depending on its origin, type, and the nature of its chemical composition, particularly the polar components. Therefore intermolecular interactions can occur, for that there is a gradation of viscosity among light, heavy and extra heavy crude oils, and bitumen. For this reason, developing a comprehensive model of viscosity to include different regions of the world crudes seems to be a very challenging task. Generally it may be said that there are two main types of correlations available for oil viscosity prediction. The first type uses the available oil field data, such as reservoir temperature, API gravity, solution gas oil ratio, saturation pressure, and reservoir pressure. The second type is empirical and/or semi empirical correlations which uses some parameters other than those used in the first type; such as reservoir fluid composition, pour point temperature, molar mass, normal boiling point, critical temperature, and acentric factor of components[2-4]. Before going into the process of constructing this correlation, the data points were subjected to three published models that worked at elevated temperature range. The first one was developed to predict viscosities on the range of 21 to 146^{o}C [5]. The second model was developed using crude oil samples from the Middle East on a temperature range of 38 to 150 ^{o}C [6]. The last model was a setup using data points on the range of 40 to 146 ^{o}C [7]. Beal (1946) stated that it is highly unlikely to correlate the viscosity of the crude with high accuracy due to the variation in compositions. Beal presented a chart that describes viscosity of 655 dead oil samples at 38 ^{o}C. The samples represented 492 oil fields around the world, covering viscosity rang of 0.8 to 155 cP, gravity range of 10.1 to 52.5^{o}API, and temperatures from 38 to 105^{o}C [8]. Kartoatmdjo and Schmidt (1994) developed an empirical correlation to measure the viscosity of dead oil of 3588 data point using 661 dead oil samples. The work was done on temperature range of 75 to 320^{o}F, gravity range of 14.4 to 58.9 ^{o}API covering viscosity range of 0.5 to 682 cP [9]. Labidi (1992) also correlated the dead oil viscosity as a function of the temperature and the gravity. His correlation was developed using 91 data points, covering viscosity range of 0.66 to 4.79 cP, temperature range of 38 to 152 ^{o}C and API range of 32.2 to 48.0 ^{o}API [10]. Labidi claims that his Equ. was more accurate than Beal [8] and Beggs [5] which might have been true on his tight range of viscosity range, but it was found to have a high error if applied out of this range. Hossain M.S. et. al. (2005) statistically analyzed a data bank covering dead oil viscosities range of 22 to 415 cp and temperatures range of 51 to 93^{o}F for oil samples with gravity in the range of 15.8 to 22.3^{o}API.

2.0 Experimental Details

2.1 Sample Preparations

Dry heavy crude oil samples were collected and filtrated using 0.45-μm Teflon membranes to remove any suspended material, and stored in dark bottles of 2.5 L overnight in dry controlled temperature chamber at 25^{o}C. The physical properties were measured and the results are tabulated in Table 1. Every sample was preheated at 60^{o}C for 24 hours. Prior to the analysis, the samples were shaken vigorously to achieve homogeneity. The sampling equipment was initially rinsed by a small amount of sample to remove any contamination from previous test.. As per the test procedures the reading is collected once stability attained.

2.2 Viscosity and density measurements

The measurements of viscosities were taken by using a viscosity monitoring and control electronics system. The main idea of this state of the art equipment was to measure the strength of an electromagnetic field generated from two magnetic coils inside a stainless steel body. This structure allows the stainless steel piston inside the measurement chamber to move by magnetic force back and forth in the fluid. The time required for the piston to move a fixed distance (about 0.2 inches) is very accurately related to the viscosity of the fluid in the chamber. The calibration of the instrument was done by a triplicate measurement of the two reference samples. Those samples were supplied by the manufacturer and the calibration was done on the temperature range of interest with reproducibility $\pm$ 0.85%. The measuring range and the estimated uncertainty in dynamic viscosity measurements was found to be not more than $9 \cdot 10^{-3}$ mPa·s with confidence interval 95% of all measurements. The densities were measured at temperature intervals between (25 and 160^{o}C) using vibrating tube density meter, (mPDS 2000) Anton paar, GmbH oscillating u-tube densitometer, work according to the oscillating U-tube techniques. The oscillation period τ, in the vibrating U-tube of the densimeter was converted to density ρ, using the following Equ.:

$$\rho = A\tau^2 - B \qquad (1)$$

where A, and B, are apparatus constant determined by using the density of dry air and ultra pure water, (S. No. 78169, S.H. Kalibrier, GmbH products) at temperature of interest. The measuring cell is thermostatic with solid-state thermostat and two integrated Pt 100, measuring sensors with temperature reproducibility of $\pm 10^{-2\,o}$C. The calibration was done at the temperatures of interest by ultra pure water. Triplicate measurements of density were performed for all samples. The results were averaged and the estimated uncertainty of the measurements was within 0.5 kg · m^{-3}.

3.0 Results and discussion

3.1 Experimental data analysis

Data points of the viscosity and the density of 31 dead heavy oil samples with different API^{o} values were measured at temperature range of 100^{o}C and 160^{o}C. These values were subjected to a simple statistical analysis to describe the distribution of the data points which is shown in Table 2. It was found that viscosity decreases with the increase of temperature, but increases with the increase of density with a very high correlation factor as shown in Table 2.

3.2 Model Development

The main objective of this paper is to develop a new model to describe viscosity and density in the best possible way. Usually, any dead oil sample is tagged by its standard API value which is measured at 15^{o}C. This value is the first input for any model. The second input is the value of the temperature at which the measurement was taken or the values of viscosity needed to be calculated at. It was found that most models calculate an intermediate parameter or sometimes two parameters using the API value and temperature to calculate the viscosity. In most cased this parameter has no physical meaning, so in our case we decided to take this intermediate parameter as density and try to model the density using the API and temperature. The goal was to create a model in the following format

$$\mu_{od} = f\left(T, \rho_{od}\right) \qquad (2)$$

where

$$\rho_{od} = f\left(T, API_{@60^o F}\right) \qquad (3)$$

where, μ_{od} is the dead oil viscosity in centipoises, T is the temperature in degree Celsius, ρ_{od} is the density of the dead oil in grams per cubic centimeter, and API is the standard oil gravity measure.

3.2-1. Density Correlation

Since density is an additive property it was simply correlated as a straight line with temperature and also with API. It can concluded that the density can be estimated from API and temperature using Equ. 4. The results of the heavy crude samples were satisfactory with R^2 value of 0.99 and an average percentage error less than 0.05%.

$$\rho_{od} = a + b\left(API_{@60^o F}\right) + c\left(T\right) \quad (4)$$

Where the correlation parameters are a, b, and c are (1.072408845, -0.00652625 and -0.0006639) respectively.

The negative values of the correlation factors shown in Table 2 between density and both API and temperatures indicates an indirect correlation for both cases.

3.2.2 Viscosity Model

The negative value of the correlation factor between viscosity and temperature indicates that there is an indirect correlation between them that follows the arrangement in Equ. 5. The positive value between the density and the viscosity indicates a direct correlation and they follow the form of Equ. 6.

$$\mu_{od} = \frac{a}{T^b} \quad (5)$$

$$\mu_{od} = c \ln \rho_{od} + d \quad (6)$$

After using different forms correlation in the literature , data analysis techniques, and applying curve fitting and regression methods, it was found that the experimental data used in this study can be correlated successfully using Equ. 7 with an average error around 11% and R^2 value of 0.97.

$$\ln\left(\mu_{od}\right) = a + \frac{b}{T^2} + c\left({\rho_{od}}^2\right)\ln \rho_{od} \quad (7)$$

Values of the correlation parameters a, b and c were evaluated twice generating two sets of parameters. The first set used to apply the model on normal temperature range (20 to 100^{o}C) and the second set for elevated temperature above 100^{o}C. The values were evaluated and tested using 3 techniques. The first one is curve fitting technique, the second one is non-linear regression, and the last one was done by least square. Table 3 shows the best values for a, b, and c, for each section of the data when the viscosity is in cP, the temperature is in ^{o}C, and the density in g.cm^{-3}.

4.0 Data Evaluation

The total number of data points were 376 representing 31 dead oil samples with different API values, each point was taken at a different temperature. It divided randomly in to two parts, training and testing with a ration 3:1. The purpose of this division is to ensure that the model can be representative not only the set in hand but also any data set. Figs. 1 and 2 are cross plots of the data vs. the proposed model. The cross plots are usually used to check how close is the model to the y=x line when plotted vs, the experimental data. The results for the low temperature region were reasonable with the average relative error almost the same for training and testing part, (average relative error ≈ 12%), Fig. 1. For the high temperature region the average relative error was 13.4% for the training part and 12.8% for the testing part is shown in Fig. 2.

Fig. 3 shows the deviation between the predicted and experimental viscosities data at different API values (high, medium, and low), giving high accuracy at higher temperature.

5. Density and viscosity data comparison

5.1 Density

Fluid densities have been estimated using Standing and Katz method, [12] added some correction factors to predict the density of crude oil. The correction factors are pressure correction factor $\Delta\rho_P$ and temperature correction factor $\Delta\rho_{T,}$ [11, 12] Equ. 8.

$$\rho = \rho_{sc} + \Delta\rho_p + \Delta\rho_T \qquad (8)$$

where ρ is crude oil density (lb·ft^{-3}) P,T and ρ_{sc} are pressure, temperature and density at standard condition of crude oil respectively, $\Delta\rho_p$ is density correction for compressibility of oils and $\Delta\rho_T$ is density correction for thermal expansion of oils. Density corrections for compressibility and thermal expansion can be estimated according to Standing's relationships, [14] Equ. 9.

$$\Delta\rho_p = \left[0.167 + (16.181)10^{0.0425\rho_{sc}}\right]\left(\frac{P}{1000}\right) \qquad (9)$$

$$\Delta\rho_T = \left[0.0133 + 152.4\left(\rho_{sc} + \Delta\rho_p\right)^{-2.45}\right] x\,(T - 520) - \left[8.1\left(10^{-6}\right) - (90.0622) x\, 10^{-0.764\left(\rho_{sc} + \Delta\rho_p\right)}\right](T - 520)^2$$

For the density of crude oil under study the pressure correction factor was neglected because all measurements were made on dead oil sample under normal pressure. Fig. 4a and 4b show the reliability of measuring density data using density model with Standing correction factor for prediction and our proposed model density, with the R^2 values and the average absolute error (ε) respectively.
proposed model.

5.2 Viscosity

One of the main challenges faced in this study is that most of the existing models are limited to certain ranges of temperature, API value, and viscosity. Some of the data points had viscosity values higher than ten thousand cP, while the maximum limit for the existing models was around 580 cP. Ten different models [5-10, 13-16] were evaluated on our data to check their capability to predict the experimental viscosity data. Some results showed good agreement while others were very poor.. The main error in the inaccuracy was due to the limitation of each model and the availability of accurate experimental data. Table 4 shows a summary of the evaluated 10 models with all their available data. It was found that the model created by Standing in 1947 gave the best results.
All the models in table 4 were used to reproduce the data points regardless of their viscosity, temperature, or API limitations. Several approaches were used to compare these models with the proposed model when applied on the data understudy.

5.2.1 First Approach: square of Pearson product moment correlation coefficient

Fig. 5 is a bar chart showing the measured values of the R^2 coefficient for all models. This Fig. shows that the value of R^2 of the model made by standing [13] had the closest value to 1, (0.95) followed by Hossain Sarica[16] in 2005 (0.91), and Elsharkawy[6] in 1992 (0.89).

5.2.2 Second Approach: absolute error percent

An error test was made in calculating the absolute error percent between the calculated and the measured value to the measure values.

$$\varepsilon = \left|\frac{Experimental - Model}{Experimental}\right| \times 100 \qquad (10)$$

The average values of the errors are shown in Table 5, and the distribution of the errors for all the models are showing in Fig. 6 .

5.2.3 Third Approach: standard deviation

Another statistical test was performed on the data and the models in hand, a measure of the standard deviation (SD) was performed between the data and its calculated values from the models as in Equ. 10:

$$SD = \sqrt{\frac{\sum_{i=1}^{n} \left(\hat{\mu}_i - \mu_i \right)^2}{n-p}} \tag{11}$$

where SD is the standard deviation, $\hat{\mu}$ is the calculated viscosity from the model, μ is the measured viscosity in the lab, n is the number of data points, and p is the number of the parameters in each model. Table 5 shows that Standing[13], Naseri[7] and Gaslo[14] returned the best values for this test while the results of the others were not relatively acceptable specially when the values were above 1000.

5.2.4 Forth Approach: Cross plots

The last test was a graphically analyzed as shown in Fig. 7 which shows the behavior of all tested models against the experimental and calculated values. Some models were giving a relatively high value of R^2 , but they were inconsistent with the real values around (y = x) line as shown in the predicted models by Nasseri in 2005 [7] and kartoatmodj in 1994 [9]. Other models like Beal[8] and Labedi [10] has a low value of R^2 and the predicted data showed a scattering behavior as shown in Fig. 7. This graphical presentation also showed that the model made by Standing best describes the data regardless to the minor scattering points around the (y=x) line between the experimental data and the model's measured value.

5.0 Conclusions

The proposed model successfully describes the density and viscosity behavior of heavy crude oil at normal and elevated temperatures. The use of the density instead of the API value was successfully implemented. Other models were not acceptable and not capable of reproducing the data such as Labedi and Beal. On the other hand some existing models such as Standing was very good in reproducing the data with high R^2, low errors and low standard deviation. These models were tested regardless of their API, temperature, nor viscosity limitations and any error in reproducing the data under study is not due to a weakness in the model but it was because of these limitations.

6.0 References

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Table 1: Descriptive statistics of the data

	API 60	T/^{o}C	μ/(cP)	ρ g·cm^{-3}
Mean	16.10	81.23	281.27	0.91
Standard Error	0.10	4.11	52.94	0.00
Standard Deviation	1.84	79.79	1026.59	0.03
Sample Variance	3.40	6366.73	1053896.19	1.03E-03
Minimum	11.77	140.20	1.78	0.84
Maximum	18.81	20.00	11322.00	0.98
Count	376	160.20	376	376

Table 2: Correlation factors

	API 60	T ^{o}C	μ(cP)	ρ cal
API 60	1			
T oC	0.090472	1		
μ(cP)	-0.23785	-0.27432	1	
ρ cal	-0.74778	-0.72887	0.346399	1

Table 3. Values of the correlation parameters.

	Low temperature (20 to 100^{o}C)	High temperature above 100^{o}C
a	10.76097	7.931926
b	275.3066	309.6578
c	107.8845	61.51976

Table 4. Summary of the evaluated models, and their API, temperature and viscosity limitations.

		API		Temp /(F)		μ /(cP)	
Author	year	low	high	low	high	low	high
This work	2012	11.77	18.81	20.0	160.0	1.78	11322
Naseri, Nikazar et al. [7]	2005	17	44	40.6	146.1	0.75	54
Labedi [10]	1992	32	48	37.8	152.2	0.6	4.8
Elsharkawy and Alikhan [6]	1999	20	48	37.8	148.9	0.6	33.7
Beggs and Robinson [5]	1975	16	58	21.1	146.1	-	-
Beal [8]	1946	10	52	37.8	104.4	0.8	188
Standing [13]	1947	10.1	52.5	37.8	104.4	0.865	1550
Gaslo [14]	1980	20	48	10.0	148.9	0.6	39
kartoatmodj Schmidt [9]	1994	14	59	26.7	160.0	0.5	586
Petrosky Farshad [15]	1995	25.4	46.1	45.6	142.2	0.725	10.249
Hossain Sarica [16]	2005	15.8	22.3	51.1	93.3	22	415

Table 5. Standard deviation (SD) and Mean Absolute Percentage Error (MAPE)

Model designation	SD	MAPE
Standing 1947	220.0	39.79
Naseri, Nikazar et al. 2005	219.5	76.02
Beggs and Robinson 1975	2158	76.82
Elsharkawy and Alikhan 1999	1043	99.51
Hossain Sarica 2005	1058	118.98
kartoatmodj Schmidt 1994	1073	122.97
Petrosky Farshad 1995	932	125.38
Gaslo 1980	220.7	458.84
Beal 1946	666.4	6420.56
Labedi 1992	908.91	2883.63
This work 2012	203.74	11.9

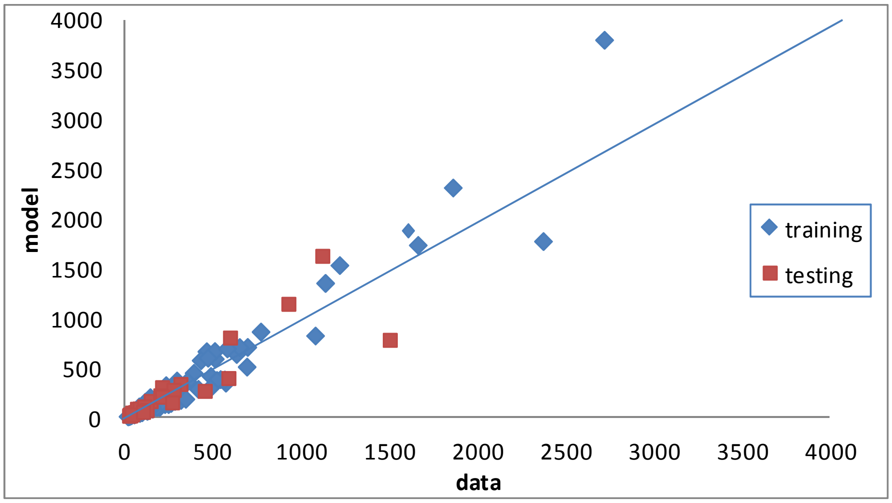

Fig. 1: Deviation of experimental data from predictive values using low temperature model, (20°C<T<100°C).

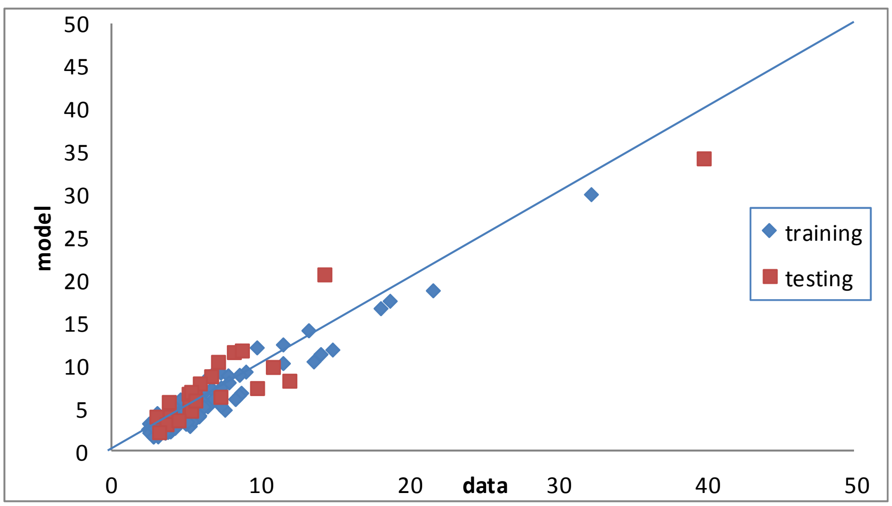

Fig. 2: Deviation of experimental from predictive values using high temperatures model, (T >100 °C).

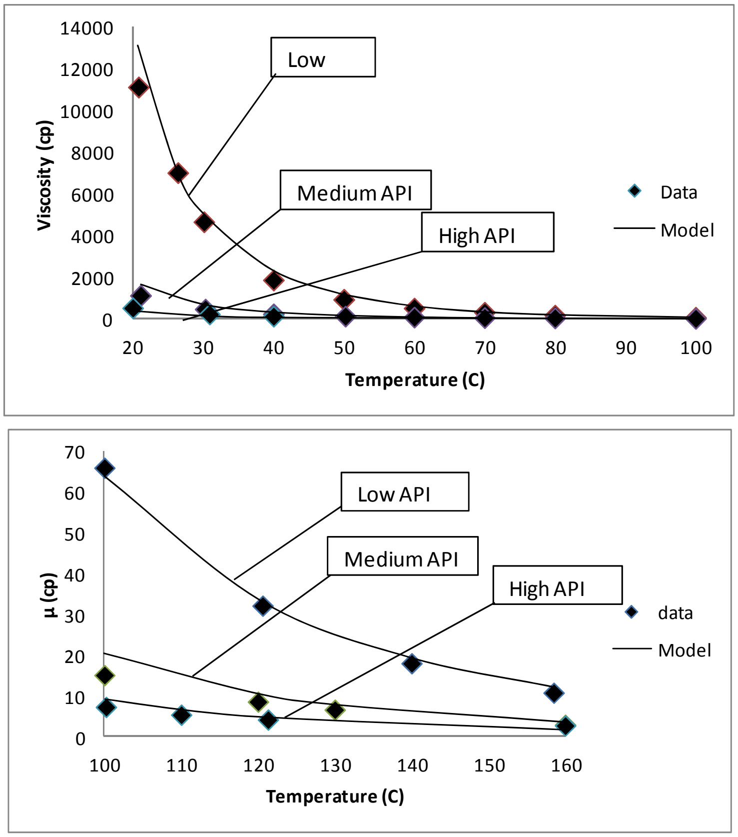

Fig. 3: Assessment of measured viscosity data at low and high temperature with the proposed model on randomly selected sample with different API values.

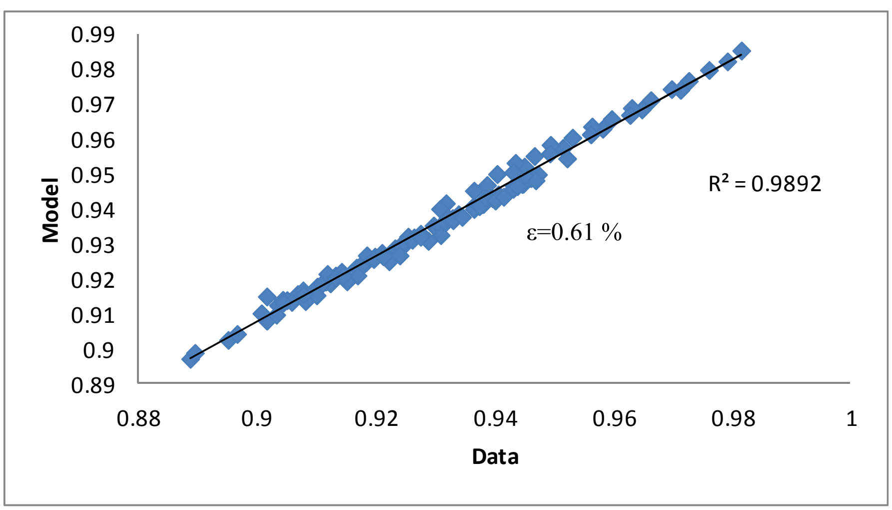

Fig. 4a. Relation between experimental density and predicted values using the published model with Standing correction factor

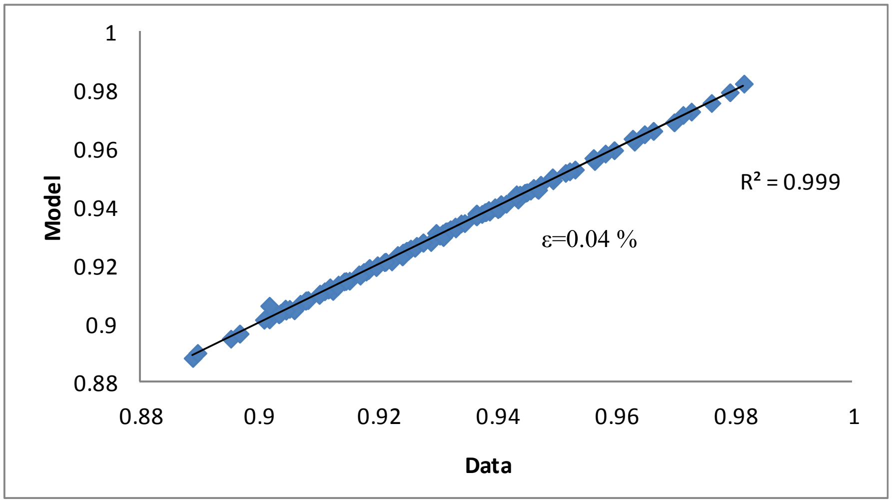

Fig. 4b. Relation between experimental density data and predicted values using our proposed model

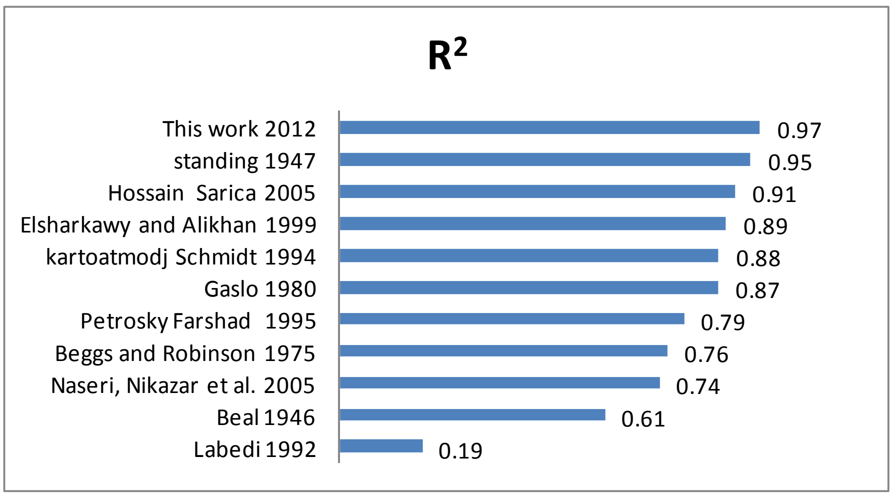

Fig. 5: Bar chart for the R^2 values for each models when applied on our data.

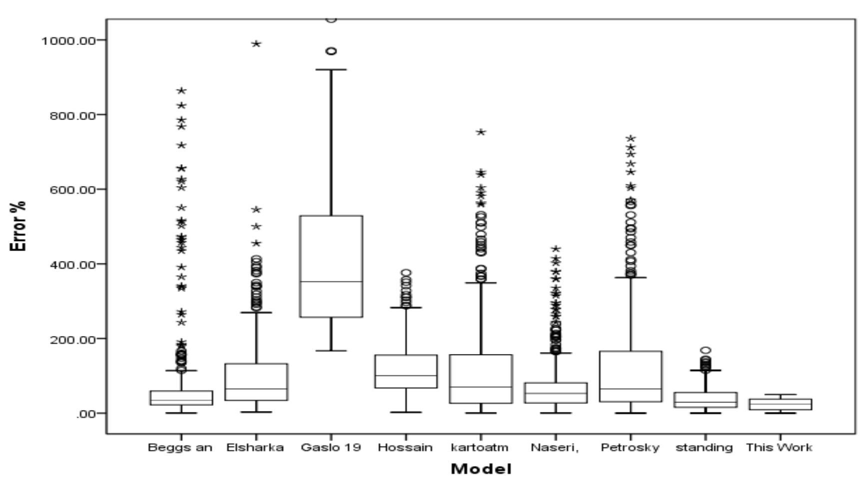

Fig. 6: Percentage error distribution on all the data points Beal and Labedi were excluded from this Fig. due to their high errors and all the tests were stopped on them after this point.

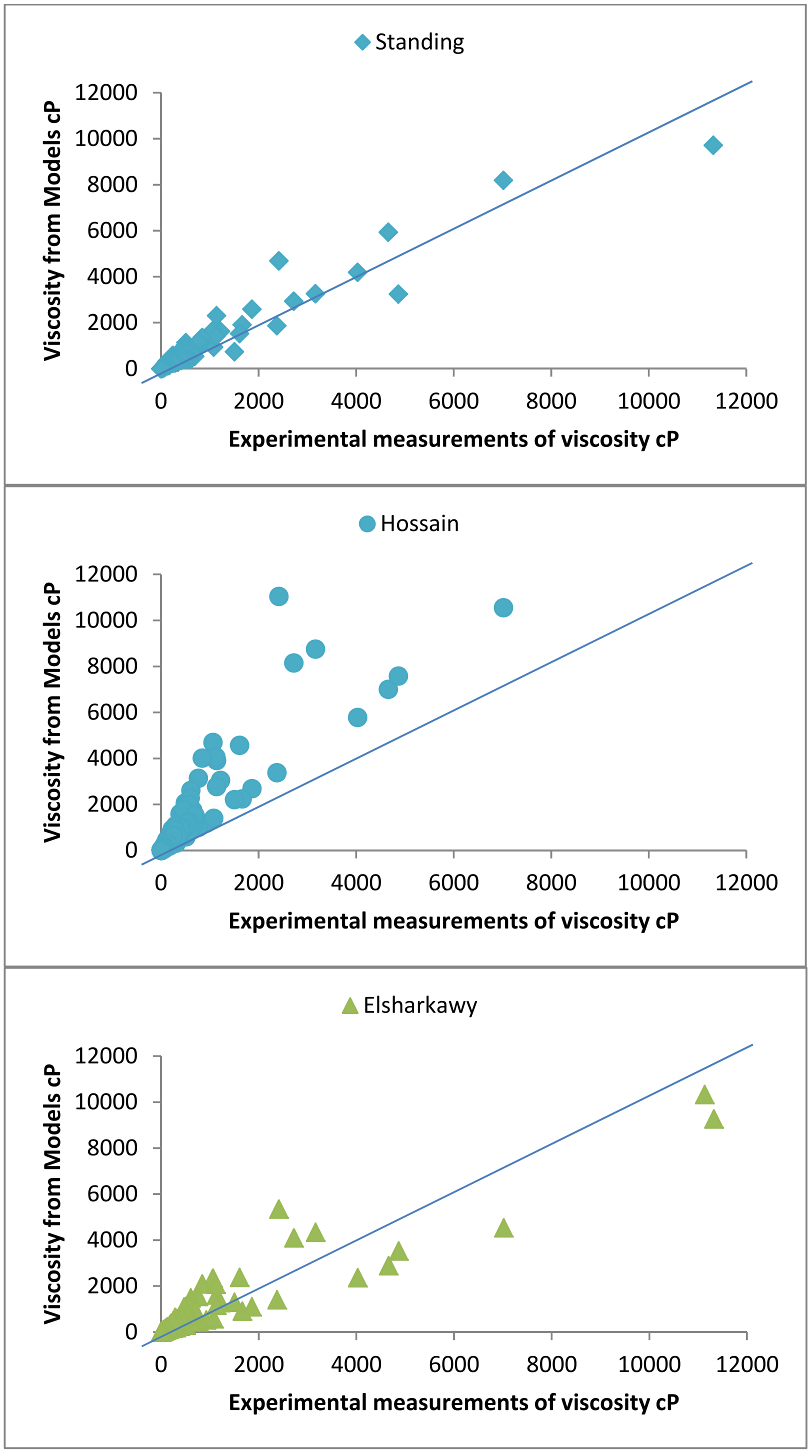

Fig. 7a. Predicted viscosity from Models vs. experimental data

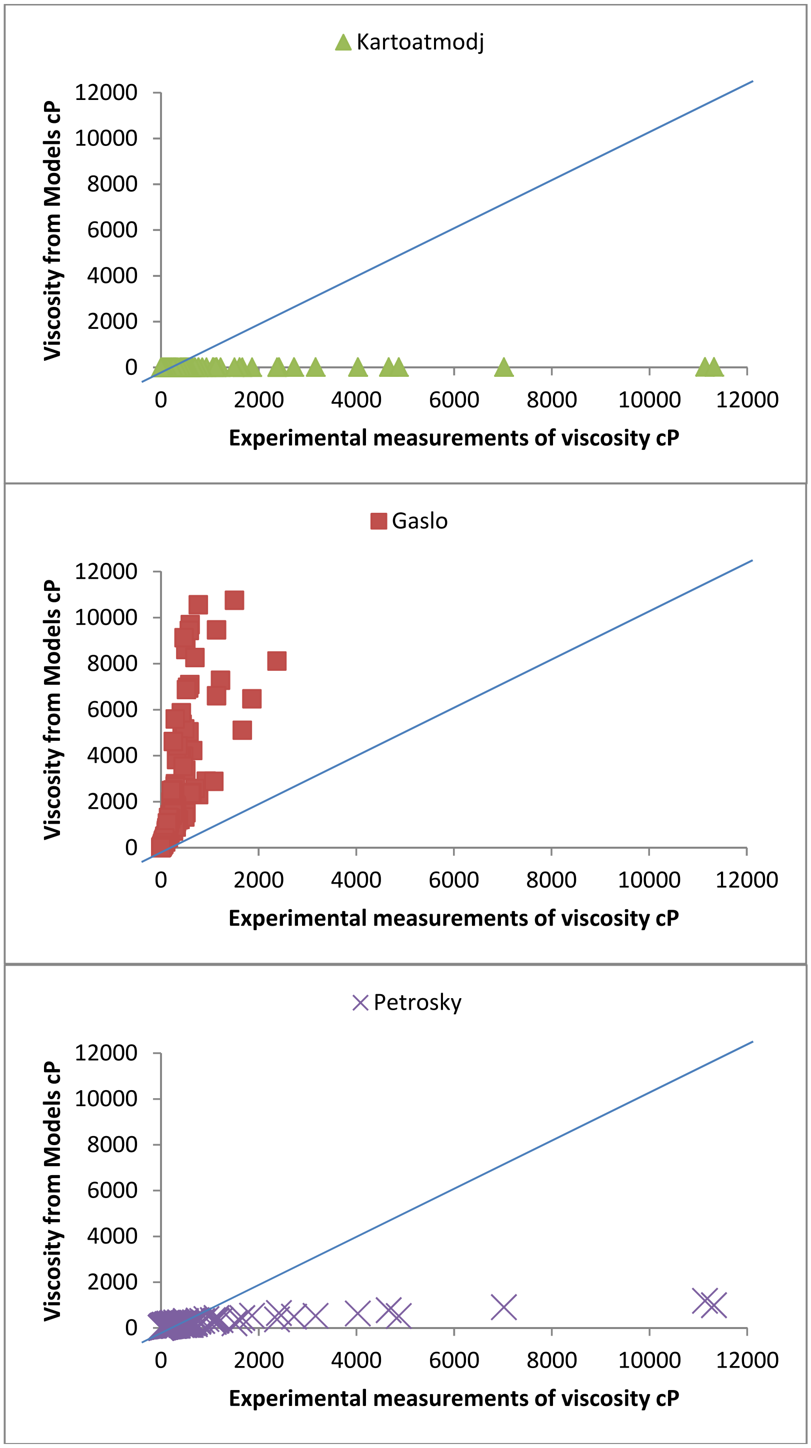

Fig. 7b. Predicted viscosity from Models vs. experimental data

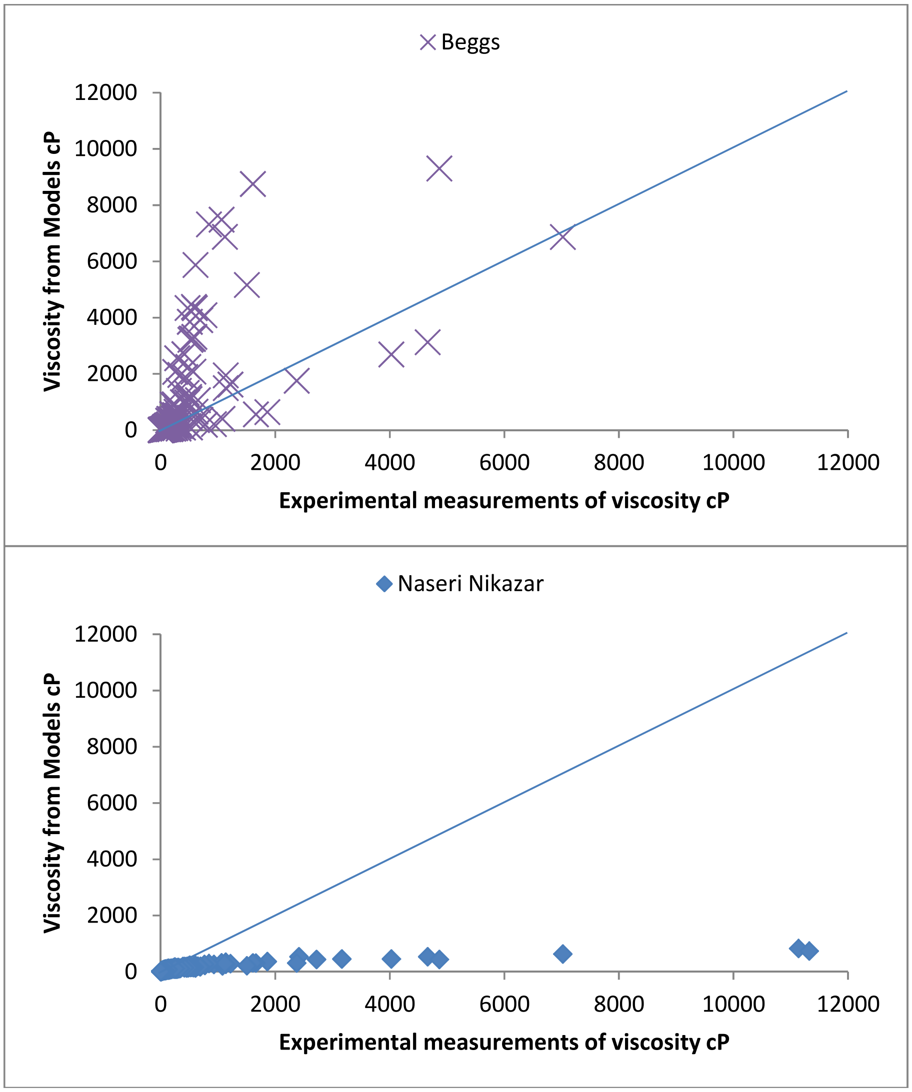

Fig. 7c. Predicted viscosity from Models vs. experimental data