Fossil Energy

EXPERIMENTAL AND THEORETICAL DETERMINATION OF HEAVY OIL VISCOSITY UNDER RESERVOIR CONDITIONS

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Under Reservoir Conditions

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EXPERIMENTAL AND THEORETICAL DETERMINATION OF HEAVY OIL VISCOSITY UNDER RESERVOIR CONDITIONS

ABSTRACT

The USA deposits of heavy oils and tar sands contain significant energy reserves. Thermal methods, particularly steam drive and steam soak, are used to recover heavy oils and bitumen. Thermal methods rely on several displacement mechanisms to recover oil, but the most important is the reduction of crude viscosity with increasing temperature.

The main objective of this research is to propose a simple procedure to predict heavy oil viscosity at reservoir conditions as a function of easily determined physical properties. This procedure will avoid costly experimental testing and reduce uncertainty in designing thermal recovery processes.

We reviewed critically the existing literature choosing the most promising models for viscosity determination in our first report. In this second part we modified an existing viscosity correlation, Pedersen et al.¹, based on the corresponding states principle in order to fit more than two thousand commercial viscosity data. We collected data for black oil samples in absence of compositional data. The data were screened for inconsistencies resulting from experimental error. A procedure based on the monotonic increase or decrease of key variables was implemented to carry out the screening process. A simple procedure is proposed to calculate black oil viscosity from common experimental information such as, boiling point, API gravity and molecular weight.

Next step will involve the extension of the modified procedure to oil samples where compositional data are available.

STATEMENT OF WORK (SOW)

Under this Statement of Work (SOW), Dr. Jorge Gabitto from the Chemical Engineering Department at Prairie View A&M University (PVAMU), Dr. Maria Barrufet from the Petroleum Engineering Department at Texas A&M University (TAMU) and Dr. Rebecca Bryant from Bio-Engineering International Inc. (BEI) will conduct research and training in the area of transport and thermodynamic properties determination for heavy oils. Chevron Oil Company will provide consulting and heavy oil samples to be used in the project.

A research project is proposed to develop theoretical models, computer algorithms, and measure experimentally transport and thermodynamic properties of heavy oils. Model evaluation will be an important part of the project.

This research will involve training of graduate and undergraduate students in state of the art techniques. Technology transfer of the results generated by the project will be achieved through Dr. Bryant's efforts and publications in refereed journals.

Dr. Gabitto will act as coordinator of the research team and he will be responsible by most of the theoretical program. Dr. Barrufet will be Co-Principal Investigator, and she will be responsible for the experimental part. Dr. Bryant will advise the research team, and she will be responsible for transferring the project's findings to small independent producers.

TECHNICAL DESCRIPTION

Introduction

The viscosity of heavy oils is a critical property in predicting oil recovery. Viscosity reduction and thermal expansion are the key properties to increase productivity of heavy oils. Thermal methods are pivotal in successfully producing oils with an API gravity of less than 20 degrees. These recovery methods may involve steam, hot water injection, and in-situ combustion². For improving heavy oil recovery, steam injection has proven to be the premier approach for both stimulating producing wells and displacing oil in the reservoir. The amount of high viscosity oil produced by steam methods is increasing annually throughout the world³.

Modern reservoir engineering practices require accurate information of thermodynamic and transport fluid properties together with reservoir rock properties to perform material balance calculations. These calculations lead to the determination (estimation) of the initial hydrocarbons (oil and gas) in-place, the future reservoir performance, optimal exploration and production schemes, and the ultimate hydrocarbon recovery. The technical and economic viability of steam flooding processes have been established by laboratory and field studies of rock formations and crude oils³. Extensive knowledge of fluid properties is required to properly develop a steam flooding strategy.

Reservoir simulators are routinely used to predict and optimize oil recovery from oil fields. These simulators require as input properties of the reservoir fluids as a function of pressure, temperature and composition. The accuracy of the fluid properties can decisively affect the results of the simulation. Among the required fluid properties are: phase densities, phase viscosities, formation volume factors (B_O), and dissolved gas-oil ratios. The proposed research program includes the measurement and thermodynamic modeling of these properties.

Objectives

The objectives of this research program are to determine viscosity and other required thermodynamic properties of heavy crude oil mixtures at various temperatures with and without steam at pressures and temperatures characteristic of steam flooding processes.

This research program has been divided in a theoretical and an experimental part. The theoretical part involves a critical literature review followed by development of a model based on the corresponding states theory. The experimental part involves measurement of viscosity of hydrocarbons mixtures and heavy oils under different temperatures and pressures characteristic of real reservoir conditions. Finally comparison between predicted and measured mixtures viscosity will be done.

The first report presented the results of our literature review and data from the first experiments completed. The modification of Pedersen et al.¹ viscosity correlation for black oils is presented here. A screening process for the experimental data used is also presented.

An Automated Data Quality Control Procedure to Screen Crude Oil Viscosity Data

Abstract

Most correlations for crude oil viscosity require additional tuning to provide acceptable predictions for a given reservoir fluid. Before recalibrating these correlations, data must be quality controlled to ensure suitable performance of regression procedures. For large data sets this data preprocessing could become tedious and laborious unless a systematic and automated consistency check is used.

For this study, we had a database of almost 3,000 records of PVT properties and black oil viscosity data, coming from 324 differential liberation tests performed in commercial laboratories.

We have developed a procedure to "clean up" the data on a test basis, before processing it with a regression routine. We individually screened each test, identified outlying observations and removed those from the regression calculations.

The criteria used to discard data relied on the numerical evaluation of the first derivative of selected functions of one variable. These functions should either always increase or decrease, when the physical behavior is predicted appropriately. For example oil viscosity (observed function) should always increase as the pressure in the differential liberation tests is decreased. Forward and backward derivatives were used to account for

the end points. The filtered data resulting from this quality control process consisted of 2,324 observations.

The data were used to adapt two compositional viscosity models, Pedersen et al.¹ and Lohrenz, Bray and Clark⁴ (LBC), so that these models can be used for black oil systems when compositional data are missing. The oil viscosity ranged from 0.18 to 78 cp, with pressure from 63 to 4,014 psia and temperature from 80 °F to 288 °F. The oil API gravity ranged from 18.6 to 53.6. These models were validated against an independent data set consisting of 150 observations. The two models had lower statistical errors than current correlations.

Introduction

Crude oil viscosity is important in the calculation of two-phase flow, gas/liquid flowing pressure traverses, tubing-string design, gas-lift design, and pipeline design. Most important of all, it is needed to calculate the recovery of the oil either from natural depletion or from recovery techniques such as water-flooding and gas-injection processes.

Live oil viscosity is a strong function of pressure, temperature, oil gravity, gas gravity, gas solubility, molecular sizes, and composition of the oil mixture. The variation of viscosity with molecular structure is not well known because of the complexity of crude oil systems. However, paraffin hydrocarbons do exhibit a regular increase in viscosity as the size and complexity of molecules increases.

Crude oil viscosity correlations are usually developed for three situations: above the bubble-point pressure, at and below the bubble-point pressure, and for dead oil⁵. Dead oil is oil without gas in solution at atmospheric pressure. Above the bubble-point, the composition of the oil mixture is constant and the viscosity changes result from compressibility: The fluid becomes heavier and its viscosity increases. At some point during production, the pressure drops below the bubble-point value, gas comes out of solution, and the oil composition changes continuously. The oil becomes heavier and more viscous, and two phases will flow in the reservoir.

Viscosity Correlations

Numerous viscosity-correlation methods have been proposed. None, however, has been used as a standard method in the oil industry. Since the crude oil composition is complex and often undefined, many viscosity estimation methods are geographically dependent. Most correlation methods can be categorized either as 'black oil' or as compositional.

Black oil correlations predict viscosities from available field-measured variables by fitting of an empirical equation. The correlating variables traditionally include a combination of solution gas/oil ratios (R_s), bubble-point pressure, oil API gravity, temperature, specific gas gravity, and the dead oil viscosity or the viscosity at the bubble-point. Chew and Connally⁵, Beggs and Robinson⁶, Khan et al.⁷, Kartootmodjo and Schmidt⁸ and Petrosky⁹ correlated oil viscosity with temperature, pressure, oil gravity and solution gas/oil ratio.

The second method derives mostly from the principle of corresponding states and its extensions. Lohrenz et al.⁴, Ely and Hanley¹⁰, Pedersen and Fredenslund¹¹, Pedersen et al.¹, and Monnery et al.¹² are among the researchers following this trend. Lohrenz et al.⁴ and Pedersen et al.¹ are probably the most common methods implemented in the majority of the commercial compositional reservoir simulators.

Methods based upon the corresponding states theory predict the crude-oil viscosity as a function of temperature, pressure, composition of the mixture, pseudo-critical properties of the mixture, and the viscosity of a reference substance evaluated at a reference pressure and temperature.

A thorough description of the viscosity prediction methods to be used in this research will be shown in the next section dealing with the modification to Pedersen et al.¹ method.

Reservoir Fluid Studies for Reservoir Engineering

A black oil reservoir fluid study consists of a series of laboratory procedures designed to provide values of the physical properties needed in the calculation method known as material balance calculations. The experiments are performed with live oil samples at pressures above and below the bubble-point pressure. Sampling procedures are discussed in detail elsewhere¹³. In general two types of samples are obtained. For bottom-hole

samples, or subsurface samples, the well is shut in and the liquid at the bottom of the wellbore is sampled. In the other sampling method, production rates are carefully monitored and the gas and liquid from the separators are recombined at the producing volumetric gas/oil ratio. Oil reservoirs must be sampled before the reservoir pressure drops below the bubble-point pressure of the oil, since at pressures below that no sampling method will give a sample representative of the original reservoir mixture.

Determining the composition of all chemical species present in the black oil is virtually impossible and impractical. In the majority of cases the composition of the light components is determined, from methane to hexane, and all the heavier components are grouped together in a plus fraction commonly labeled as the heptane plus fraction.

Material balance calculations are in fact volumetric calculations in which the reservoir fluids volumes filling the pore space are determined as a function of pressure. Corrections to account for rock compressibility effects and water encroachment are also included. The reservoir is considered as a tank filled with oil, gas and water. As production takes place these volumes change as illustrated in Fig. 1.

Standard reservoir PVT fluid studies are designed to simulate processes at which oil and gas displace from the reservoir to surface.

In a constant composition expansion test (CCE) a sample of the reservoir fluid is placed in a variable volume PVT cell at the reservoir temperature. The pressure is adjusted at or above the original reservoir pressure. Pressure is reduced by incrementally increasing the cell volume, and pressure/volume pairs are recorded and plotted. The pressure at which the slope changes is the bubble-point pressure and the volume at this point is the bubble-point volume. All of the liberated gas remains in contact with the oil until the two phases reach equilibrium, neither gas or liquid is removed from this cell during the process; therefore, the overall composition remains constant. This test also provides isothermal oil compressibility. Fig. 2 is a sketch of this laboratory process.

The production path of reservoir fluids from the reservoir to surface is simulated in the laboratory by a set of stage-wise flashings of the live oil at reservoir temperature. These tests are labeled differential liberation tests (DL). Here the sample is placed in a PVT cell at its bubble-point pressure. Then, pressure is reduced by incremental increases in the cell volume. The difference in this test is that all the gas liberated is expelled from

the cell while the pressure is held constant by using a dual-cell arrangement. The gas is collected, and its quantity and specific gravity are measured. During this process the oil volumes and the amount of gas released are measured and used to determine oil and gas formation volume factors (B_o , and B_g) and solution gas/oil ratios as a function of pressure R_s . Fig. 3 shows a schematic of the differential liberation process that ends at atmospheric pressure. The liquid phase is called ‘dead’ oil. The temperature is then reduced to 60°F and the volume of this oil is identified as residual oil. Table 1 shows one out of the 324 differential liberation (DL) sets used in this study, and Table 2 shows the corresponding viscosity data.

The oil formation volume factor B_o gives an idea of the shrinkage experienced by a unit volume of reservoir as it goes from reservoir pressure and temperature to standard pressure and temperature, or stock tank conditions, while the solution gas/oil ratio at a given pressure provides the amount of dissolved gas (which will be eventually produced) expressed as standard cubic feet per barrel of oil at standard conditions.

The oil viscosity is usually measured in a rolling-ball viscometer or a capillary viscometer, either designed to simulate differential liberation. The composition of the oil sample is not measured in either of the DL stages. The viscosity measured at the lowest pressure usually has the highest uncertainty.

Data Preparation and Data Screening Routine

The viscosity correlations proposed are expressed as functions of other variables or properties that are either measured or calculated from correlations. These variables include oil density, molecular weight, pseudo-critical properties, pressure and temperature, among others. The correlation will be meaningless if the quality of these variables, or the quality of the data, is questionable. In that case one may be attempting to calculate parameters by fitting errors.

During the DL process the oil becomes heavier and some physical properties should monotonically increase as the pressure decreases. These include V_{cm} , T_{cm} , T_b , M_{wm} , oil density and oil viscosity. The mixture critical properties are not known and rather pseudo-critical properties are used, but they should follow the same trend as the true critical. These pseudo-critical properties and molecular weights are not actually

measured but correlated to measurable variables such as the oil density and the normal boiling point. For lighter oils the critical pressure may go through a maximum before it starts decreasing, as the oil becomes heavier¹⁴.

Most correlations for crude oil viscosity require additional tuning to provide acceptable predictions for a given reservoir fluid. Before recalibrating these correlations, data must be quality controlled to ensure suitable performance of regression procedures. For large data sets this data preprocessing could become tedious and laborious unless a systematic and automated consistency check is used.

For this study, we had a database of almost 3,000 records of PVT properties and black oil viscosity data, coming from 324 differential liberation tests performed in commercial laboratories.

Sometimes the data may be of good quality but the correlation may be applied beyond its range. We verified that M_{wm} , T_{cm} and V_{cm} were monotonically increasing. The correlations used provide the correct behavior for oil specific gravities above 0.6. Since we had oils with lower specific gravities below 0.6 we extrapolated the correlations following a consistent trend as indicated in Fig. 4.

We have developed a procedure to "clean up" the data on a DL test basis, before processing it with a regression package. We individually screened each test, identified outlying observations and removed those from the regression calculations.

The criteria used to discard data relied on the numerical evaluation of the first derivative of selected functions of one variable. These functions should either always increase or decrease, when the physical behavior is predicted appropriately. For example oil viscosity (observed function) should always increase as the pressure in the differential liberation tests is decreased. Forward and backward derivatives were used to account for the end points. The filtered data resulting from this quality control process consisted of 2,324 observations.

The data were classified according to test number. Each DL is characterized by temperature and API gravity of the residual oil. The highest pressure in every set corresponds to the bubble-point pressure at that temperature. This pressure is extracted and written to a file for use in the correlations for solution gas/oil ratio and formation volume factor. The viscosity data were contained in separate files and even though these

corresponded to the same DL tests, some viscosity measurements were missing or were done at different pressures. Assembling of these two sets of files was done one to one match. The missing pair was removed from either set and stored in a separate file.

Each matched DL and viscosity set contained between 6 and 10 observations at declining pressures. Properties were evaluated for these observations and stored.

Forward and backward derivatives were used for viscosity and oil density versus pressure. The first derivative of these functions should always be negative. If a point violated this monotony criterion all measured properties at that pressure were discarded.

Occasionally the oil density exhibited a consistent behavior within some acceptable scatter and the data points passed the consistency test. However, if derived properties (M_{wm} , T_{cm} , V_{cm}) magnified the inconsistency, these were included in the list of checking variables and provided a more rigorous screening.

The number of points left in a DL set should be at least 4. Even if these appeared to be correct, the fact that the remaining points were discarded made the test questionable.

Data Screening Results

Figures 5 to 7 indicate examples of removed data. You can find deviations from a monotonic trend for different properties. These deviations are caused by experimental and/or human errors. With all the cleaned data we proceeded to develop correlations for the viscosity based upon the modified Pedersen¹ and Lohrenz⁴ models. Additionally we proposed new correlations for solution gas-oil ratios and formation volume factors to be used in these models.

Modification of Pedersen's Model for Saturated Crude Oil Viscosities

This section presents a modification of Pedersen's corresponding states compositional viscosity model that enables viscosity prediction for black oil systems when there are no compositional data available. This model can be easily implemented in any reservoir simulation software, it can be easily tuned, and it provides better estimates of oil viscosity than the existing correlations.

Viscosity from 324 sets of differential liberation data consisting of 2343 observations covering a wide range of pressure, temperature, and oil density were used to develop the correlation. This correlation retains most of the functional form of Pedersen's model. These modifications include (1) use of n-decane as the reference fluid, (2) consider the oil mixture as a single pseudo-component with molecular weight and critical properties correlated to its density, and (3) addition of a functional dependence to solution gas/oil ratio and gas-specific gravity. The average error over 2343 viscosity observations was 0.9%. The model was tested against a second data set consisting of 150 observations and the average error was 0.7 %.

The predictions were compared with those predicted from the correlations of Khan *et al.*⁷ and of Petrosky⁹ that are applicable to the experimental conditions of our data sets. These average errors for these correlations were -28 % and 4.9 % respectively for the first data set; and -60.8 % and -1.4 % for the second data set.

Viscosity Correlations

Numerous viscosity-correlation methods have been proposed. None, however, has been used as a standard method in the oil industry. Most correlation methods can be categorized either as 'black oil' or as compositional.

Black oil correlations predict viscosities from available field-measured variables by fitting of an empirical equation. The correlating variables traditionally include a combination of solution gas/oil ratios (R_s), bubble-point pressure, oil API gravity, temperature, specific gas gravity, and the dead oil viscosity or the viscosity at the bubble-point.

The second method derives mostly from the principle of corresponding states and its extensions. Methods based upon the corresponding states theory predict the crude-oil viscosity as a function of temperature, pressure, composition of the mixture, pseudo-critical properties of the mixture, and the viscosity of a reference substance evaluated at a reference pressure and temperature.

Lohrenz *et al.*⁴ published the now well-known LBC correlation suitable for gases and light oils. The LBC correlation is a fourth-degree polynomial in the pseudo-reduced density of the mixture and this makes it very sensitive to this variable.

$$\left[(\mu - \mu^*) \xi + 10^{-4} \right]^{1/4} = \sum_{i=1}^5 a_i \rho_r^{i-1} \quad (1)$$

Here μ^* is the low-pressure gas mixture viscosity, and ξ is the viscosity-reducing parameter, which is defined as,

$$\xi = T_{cm}^{-1/6} M_{wm}^{-1/2} P_{cm}^{-2/3} \quad (2)$$

Ely and Hanley¹⁰ (1981) proposed the following extended corresponding states model:

$$\eta_i(\rho, T) = \eta_o(\rho_{hi,o}, \frac{T}{f_{i,o}}) \left(M_i / M_o \right)^{1/2 - 2/3 \frac{1}{f_{i,o}}} \quad (3)$$

$$h_{i,o} = h_{i,o}(\rho_{c,i} / \rho_{c,o}) \phi_{i,o} \quad (4)$$

$$f_{i,b} = (T_{c,i} / T_{c,o}) \theta_{i,o} \quad (5)$$

where $\theta_{i,o}$, and $\phi_{i,o}$ are shape factors depending on the chemical components. Viscosity calculations require correlations for a reference fluid viscosity and density along with critical properties values, acentric factor and molar mass. Methane was selected as a reference fluid because of the availability of highly accurate data. A problem using methane is its high freezing point ($T_r = 0.48$), which is well above the reduced temperatures of other fluids in the liquid state. In order to overcome this difficulty they extrapolated the density correlation for methane and added an empirical correlation for non-correspondence and extended the viscosity correlation of Henley et al.¹⁵ (1975).

Pedersen et al.¹ introduced a third parameter (α) to correct for this deviation from the conventional corresponding states principle. This term accounts for the molecular size and density effects on viscosity. Their model eliminates the iterative procedure in Ely and Hanley¹⁰ and performs a direct calculation of the viscosity.

These authors proposed a similar approach for hydrocarbon and crude oil viscosities:

$$\eta_x(P,T) = (T_{c,x}/T_{c,o})^{-1/6} (P_{c,x}/P_{c,o})^{2/3} (M_i/M_o)^{1/2} \alpha_{TG,x} / \alpha_{TG,o} \eta_o(P_o^*, T_o^*) \quad (6),$$

and,

$$T_o^* = (T_{c,x}/T_{c,o}) (\alpha_{TG,o} / \alpha_{TG,x}) \quad (7)$$

$$P_o^* = (P_{c,x}/P_{c,o}) (\alpha_{TG,o} / \alpha_{TG,x}) \quad (8),$$

where α_{TG} is the Tham-Gubbins¹⁶ (1971) rotational coupling coefficient.

According to Pedersen et al.¹ the problems associated with representing poly-disperse mixtures (such as crude oils) are associated with the computation of average molar mass. Their results indicated that larger molecules should make a greater contribution to viscosity than the smaller ones. The mixture molar mass was calculated empirically as,

$$M_n = M_n + b_1 (M_w - M_n) \quad (9),$$

where b_1 is an empirical constant obtained by fitting experimental data, α_{TG} was determined from the molar mass and reduced density. The mixture viscosity was calculated from eqn. (4) with the mixing rules provided for pseudo-critical properties.

Pedersen and Fredenslund¹⁷ (1986) extended Pedersen et al.¹ method to mixtures with T_r below 0.4 (below methane freezing point) by modifying the equations for M_n and α_{TG} .

Model Development

Since most of the features from our correlation resemble Pedersen et al.¹ model we rewrite their model here.

$$\mu_m(P,T) = \left(\frac{T_{cm}}{T_{co}} \right)^{\alpha_1} \left(\frac{P_{cm}}{P_{co}} \right)^{\alpha_2} \left(\frac{MW_m}{MW_o} \right)^{\alpha_3} \left(\frac{\alpha_m}{\alpha_o} \right) \mu_o(P_o, T_o), \quad (10),$$

where the coefficients α_1 , α_2 and α_3 in Pedersen's model are -1/6, 2/3 and 1/2 respectively.

$$\alpha_m = 1.000 + 7.378 \times 10^{-3} \rho_{ro}^{1.847} MW_m^{0.5173} \quad (11)$$

$$\alpha_o = 1.000 + 0.031 \rho_{ro}^{1.847} \quad (12).$$

Here, ρ_{ro} is the reduced density of the reference fluid. Pedersen et al.¹ used methane as the reference fluid. They used a BWR-equation in the form suggested by McCarty¹⁸ to

evaluate the density of methane. This density is evaluated at a reference pressure and temperature as indicated in Eqn. (13)

$$\rho_{ro} = \frac{\rho_o \left(\frac{PP_{co}}{P_{cm}}, \frac{TT_{co}}{T_{cm}} \right)}{\rho_{co}} \quad (13),$$

the pressures and temperatures at which the reference viscosity (μ_o) is evaluated are given by,

$$P_o = \frac{PP_{co} \alpha_o}{P_{cm} \alpha_m} \quad \text{and} \quad T_o = \frac{TT_{co} \alpha_o}{T_{cm} \alpha_m} \quad (14).$$

The critical temperature and pressure are found using the mixing rules suggested by Mo and Gubbins¹⁹ using the composition of the oil mixture. The method is highly sensitive to the characterization of the heavy fraction, usually known as the C_7^+ fraction. Our objective was to extend this model to black oil mixtures for which we do not have compositional information.

The limitation of methane as the reference substance is that when the reduced temperature of methane is below 0.4, it will freeze. This is above the reduced temperatures for most reservoir fluids. Pedersen et al.¹ solved this problem by modifying the viscosity model of Hanley et al.¹⁵, while Monnery et al.¹² suggested using propane as a reference fluid.

To use Eqn. (10) we needed to find simplified expressions for the molecular weight (MW_m), critical temperature and pressure (T_{cm} , and P_{cm}) of the mixture, and for the density and viscosity of the reference fluid. We initially used methane as the reference fluid, but rather than implementing Pedersen's modifications, which are tedious and add additional complexity to the model, we decided to use an alternative reference fluid. We selected n-decane for this purpose.

The viscosity and density data for n-decane were taken from various sources reported by Geopetrole²⁰ covering pressures from 14.7 psia to 7325 psia and temperatures from 492°F to 762°F. The density and viscosity of n-decane were fitted as a function of P and T using a stepwise regression procedure and the statistical software SAS²¹. The density, in lb/ft³, is calculated by

$$\rho_{C10} = \exp(-1847.7998 \times T^{-1} + 168.1906 \times T^{-1/2} + 1.5043 \times 10^{-8} TP). \quad (15),$$

while the viscosity, in cp, is given by,

$$\mu_{C10} = 50991.51 \frac{1}{T} + 2321.5418 \times T^{-1/3} - 8775.2881 \times T^{-1/2} + 0.4775 \frac{P}{T} - 0.001272 \times P - 6.7057 \times 10^{-9} \times T^3 + 8.87 \times 10^{-7} \times PT \quad (16).$$

The correlation coefficient for Eqn. (6) is $R^2 = 0.9996$ with minimum and maximum errors of -1.47% and $+1.82\%$ respectively. Eqn. (7) has a correlation coefficient of $R^2 = 0.9998$ and gives minimum and maximum errors of -3.11% and $+8.21\%$ respectively. The pressures and temperatures that appear in Eqns. (15) and (16) are in psia and Ranking degrees, respectively.

The specific gravity of the oil was evaluated from a material balance using the reported values of formation volume factor (B_o), solution gas/oil ratio (R_s), and gas specific gravity according to McCain²². The reported specific gravity of the gas was for the separator at 100 psia rather than at atmospheric pressure, however; the error introduced in the determination of specific gravity of the oil is negligible.

The oil mixture was lumped into a single pseudo-component for which the critical temperature, the critical pressure, and the molecular weight were correlated to the oil specific gravity.

Most correlations for the critical properties require at least two properties from the molecular weight, the density, and the normal boiling point. We had only one of these variables. To overcome this problem we assumed that for most oils the percentage of paraffinic compounds dominates and in that case we correlated the normal boiling versus specific gravity of oil at reservoir conditions ($\gamma_{o,R}$). Once this was determined the molecular weight was correlated to the normal boiling point in R. The data to develop these correlations were reported by Ahmed²³ and Whitson²⁴.

The normal boiling point in R, and the mixture molecular weight are given by:

$$T_b = 3540.53 - 385.934312 \frac{1}{\gamma_{o,R}} - 5431.82548 \times \gamma_{o,R} + 4193.44761 \times \gamma_{o,R}^3 \quad (17)$$

$$MW_m = 64.611 \times \exp(0.0022 \times T_b) \quad (18).$$

Once these two properties were obtained the critical pressure P_{cm} was obtained using the Riazi-Daubert²⁵ correlation, while the T_{cm} was calculated using the following relationship:

$$T_{cm} = 24.2787 \times T_b^{0.58848} \times \gamma_{o,R}^{0.3596} \quad (19).$$

We observed that the critical pressure, P_{cm} , was not always monotonic as the oil became heavier. Particularly for lighter oils, P_{cm} went through a maximum and it decreased at the later stages of depletion. Since we wanted to generalize the equation for heavier and lighter oils, we selected V_{cm} as the correlating variable since it increases monotonically as the oil becomes heavier. The correlation used for V_{cm} was also from Riazi-Daubert²⁵.

If the hydrocarbon mixture had a larger percentage of aromatic compounds, the correlation for the molecular weight and normal boiling points would have to be modified. For example, the molecular weight of an aromatic component with a T_b of 640°F is about 179 lb/lb-mol, while the same boiling point corresponds to a paraffinic mixture with average molecular weight of about 260 lb/lb-mol.

The database was screened for consistency following and automated scheme shown above. The method screens for outliers in a given data set and discards the viscosity points that do not follow a consistent pattern, i.e. viscosity should increase monotonically as the pressure decreases.

In conclusion oil viscosity is calculated using,

$$\begin{aligned} \mu_m(P, T) = & \left(\frac{T \times T_{cm}}{T_{cC10}^2} \right)^{1.0286} \left(\frac{V_{cm}}{V_{cC10}} \right)^{0.9841} \left(\frac{R_s \times \gamma_{o,R}}{R_{sb}} \right)^{-0.1362\gamma_{o,R}} \left(\frac{MW_m}{MW_{C10}} \right)^{-3.9243} R_{sb}^{-0.4471} API^{-2.2902} \\ & \times \exp \left(-0.2606 \times \left(\frac{B_o}{B_{ob}} \right)^3 - 0.02359 \frac{P \times V_{cm}}{T_{C10}} + 2.1388 \frac{\rho_{C10}}{\rho_{cC10}} + 0.1930 \mu_{C10}(P_o, T_o) \right) \end{aligned} \quad (20),$$

where B_o , the formation volume factor, is dimensionless, $\gamma_{o,R}$ is the specific gravity of oil at reservoir conditions, API is the gravity of the oil at standard conditions, R_s is the solution gas/oil ratio in SCF/STB (standard cubic feet per stock tank barrel). R_{sb} and B_{ob} are evaluated at the bubble point pressure.

The advantage of this model is that it can be easily retuned if necessary using linear regression. The exponent for the variable (B_o/B_{ob}) was determined independently and it is left as a fixed parameter. The n-decane density and viscosity were evaluated at the same reference pressure and temperature indicated in Eqns. (13) and (14), and the same values for α_m and α_o defined in Eqns. (11) and (12) were used. No attempt was made to retune these values.

Results

Our model was developed using a data set of 2,343 points (Data Set 1) and it was validated with an independent data set from Core laboratories consisting of 150 observations (Data Set 2). Table 3 indicates the ranges of viscosity, temperature, and pressure for the two sets.

To evaluate the performance of this model we selected two different models. These models do not assume the knowledge of the dead-oil viscosity. Khan et al.⁴ proposed a correlation for the bubble point viscosity, while Petrosky⁹ proposed a correlation for the dead-oil viscosity. The experimental ranges of pressure, oil gravity, temperature, and solution-gas/oil ratios are similar to those of our databases.

Figs. 8 and 9 show predicted versus experimental viscosities for Data Set 1 according to Khan's et al. correlation, and to Petrosky's correlation. Fig. 10 shows the performance of the adapted untuned Pedersen model, Eqn. (10) with the original coefficients but using n-decane as the reference fluid, while Fig. 11 shows the predicted versus the experimental viscosity for from this work. Figures 12 to 15 depict the predicted versus experimental viscosities for Data Set 2 according to Khan's et al. correlation, Petrosky's correlation, the untuned Pedersen's model Eqn. 10, and this work respectively.

If the parameters α_1 to α_3 from Eqn. 10 are determined for every set, then the fit can be substantially improved as indicated in Fig. 16. Current research efforts seek to generalize the dependence of the parameters α_1 to α_3 with $^{\circ}API$, R_{sb} and other field derived variables. Table 4 summarizes the statistics for these models.

Conclusions

We presented a new viscosity correlation derived from Pedersen's corresponding states model, which does not require compositional information and can be used for black oil fluids. This model can be easily implemented in any reservoir simulation software, it can be easily tuned, and it provides better estimates of oil viscosity than the existing correlations.

FUTURE WORK

The next step will be to use a 'pseudo-component' method to characterize compositionally heavy oil samples. A description of this method has been presented in the first report. Some heavy oil samples reported in literature²⁶ and others provided by Dr. Rebecca Bryant from Bio-Engineering International will be used in this work. After characterization the viscosity prediction method presented in this work will be modified and applied to the characterized heavy oil samples. A methodology to predict heavy oil viscosity when compositional information is available will be presented.

NOMENCLATURE

API	=	Oil gravity, ($API = 145/\gamma_{o,STC} - 135$)
B_o	=	Oil formation volume factor, (RB/STB)
B_{ob}	=	Oil Formation Volume Factor at the Bubble-point, RB/STB
MW_m	=	Mixture molecular weight
P_{cm}	=	Mixture critical pressure (psia)
P	=	Pressure (psia)
P_b	=	Bubble-point pressure, psia
P_r	=	Reduced pressure, p/pb
R_s	=	Solution Gas/Oil Ratio, (SCF/STB)
R_{sb}	=	Solution gas-oil-ratio at the bubble-point, (SCF/STB)
R_{sr}	=	Reduced solution gas-oil ratio, R_s/R_{sb}
T	=	Reservoir Temperature, ($^{\circ}F$, R)
T_{cm}	=	Mixture critical temperature (R)
V_{cm}	=	Mixture critical volume, ($ft^3/lbmol$)
$\gamma_{o,R}$	=	Oil specific gravity at reservoir conditions
ρ	=	Density (lb/ft^3)
α_m	=	parameter defined in Eqn. (11)
α_o	=	parameter defined in Eqn. (12)
μ	=	Oil viscosity, cp

Subscripts

o	=	reference conditions, oil
$c10$	=	n-decane.
r	=	reduced
c	=	critical
m	=	mixture
b	=	at bubble point, or normal boiling point (Eq. 8).
o,R	=	oil at reservoir conditions
$g,100$	=	gas at 100 psia.

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TABLES AND FIGURES

Table 1. Differential Vaporization Test at 80 °F.

Pressure (psig)	R_s ^[1] (SCF/ STB)	B_o ^[2] (RB/ STB)	Oil Density ρ_o (gm/cc)	Gas Deviation Factor Z	B_g ^[3] (RCF/ SCF)	Gas Gravity γ_g
1690	210	1.069	0.9022			
1500	188	1.063	0.9052	0.822	0.00825	0.581
1300	165	1.056	0.9083	0.835	0.00966	0.576
1100	141	1.049	0.9113	0.852	0.01162	0.573
900	117	1.042	0.9143	0.872	0.01450	0.571
700	93	1.036	0.9174	0.896	0.01906	0.572
500	68	1.029	0.9205	0.922	0.02724	0.574
300	42	1.022	0.9235	0.951	0.04593	0.581
100	15	1.014	0.9268	0.983	0.13004	0.600
0	0	1.008	0.9305			0.724

Gravity of Residual Oil = 19.2° API @ 60°F

[1] Cubic feet of gas at 14.7 psia and 60°F per barrel of residual oil at 60°F.
[2] Barrels of oil at indicated pressure and temperature per barrel of residual oil at 60°F.
[3] Barrels of oil plus liberated gas at indicated pressure and temperature per barrel of residual oil at 60°F.
[4] Cubic feet of gas at indicated pressure and temperature per cubic foot at 14.7 psia and 60°F.

Table 2. Viscosity Data Accompanying DL Set at 80 °F and 19.2 °API Residual Oil.

Pressure (psig)	Oil Viscosity (cp)	Calculated Gas Viscosity (cp)	Oil/Gas Viscosity Ratio
1690 (P_b)	35.4		
1500	40.0	0.0146	2740
1300	45.2	0.0140	3230
1100	51.2	0.0134	3820
900	58.5	0.0129	4530
700	68.4	0.0124	5520
500	82.5	0.0120	6880
300	102.1	0.0116	8800
100	127.6	0.0113	11300
0	177.0	0.0106	16700

Table 3. Range of input data. SI units and values in are indicated in parenthesis.

Dataset	N° Points.	Variable	Minimum	Maximum
#1	2343	Oil Density: lbm/ft ³ (g/cm ³)	35.11 (0.562)	57.31(0.92)
#2	150	Oil Density, lbm/ft ³ (g/cm ³)	24.31 (0.389)	57.50(0.921)
#1	2343	Oil Viscosity, cp	0.132	78.30
#2	150	Oil Viscosity, cp	0.13	68.90
#1	2343	Temperature, R (K)	540 (300)	766 (425.5)
#2	150	Temperature, R (K)	537 (303.9)	762 (423.3)
#1	2343	Pressure, psia (MPa)	14.7 (0.1)	5601.7 (38.62)
#2	150	Pressure, psia (MPa)	102.7 (0.708)	5434.7 (37.47)

Table 4. Summary of the black oil viscosity models performance.

Model	Number of Observations	Maximum Error, %	Minimum Error, %	Average Error, %
Khan	2343	81.6	-567	-28
Khan	150	66.1	-636	-60.8
Petrosky	2343	80.1	-214	4.9
Petrosky	150	44.8	-111	-1.4
Adapted Pedersen	2343	99.2	-384.	62
Adapted Pedersen	150	98.9	-382	54
This Work	2343	77.7	-317	0.9
This Work	150	58.7	-189	-0.7

Fig. 1. PVT Properties Used in Material Balance Computations.

Fig. 2. Crude Oil Constant Composition Expansion Test.

Fig. 3. Crude Oil Differential Liberation Test.

Fig. 4. Pseudo-critical Volume (V_{cm}), Mixture Molecular Weight (M_{wm}) and Normal Boiling Point (T_b) as a Function of Oil Specific Gravity.

Fig. 5. Removed Data at P=200 Bar Due to Inconsistent Physical Trend.

Fig. 6. Removed End Point Viscosity. Violation of Monotonic Behavior.

Fig. 7. Removed Oil Density at P = 200 Bar Due to Inconsistent Trend.

Fig. 8. Predicted Viscosity vs. Experimental Viscosity – Khan *et al.* model (Data Set 1)

Fig. 9. Predicted Viscosity vs. Experimental Viscosity – Petrovsky model (Data Set 1)

Fig. 10. Predicted Viscosity vs. Experimental Viscosity – Untuned Adapted Pedersen’s model (Data Set 1).

Fig. 11. Predicted Viscosity vs. Experimental Viscosity – This work (Data Set 1)

Fig. 12. Predicted Viscosity vs. Experimental Viscosity – Khan model (Data Set 2 –Core Lab).

Fig. 13. Predicted Viscosity vs Experimental Viscosity – Petrosky model (Data Set 2 – Core Lab).

Fig. 14. Predicted Viscosity vs. Experimental Viscosity – Untuned Adapted Pedersen's model (Data Set 2 – Core Lab).

Fig. 15. Predicted Viscosity vs. Experimental Viscosity – This work (Data Set 2 – Core Lab).

Fig. 16. Predicted Viscosity vs. Experimental Viscosity – Adapted Pedersen's Model tuned per set.