Correlation of Fluid Properties and Geochemical Parameters with Heavy Oil Viscosity and Density on Trans-regional Scale

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Abstract

The aim of the study is to find correlations of geochemical characteristics with oil viscosity for heavy oils from different basins worldwide. On regional scale, oil viscosity, i.e. viscosity for oils from the same petroleum system, is a function of magnitude of alteration. For the present study, we investigated 15 heavy oils from different reservoirs and basins using biomarker parameters obtained from gas chromatography - mass spectrometry (GC-MS) analysis. Our study shows that the degradation-viscosity correlation cannot be applied to compare heavy oils from different basins. Moreover, heavy oil viscosity/density is predominantly determined by original thermal oil maturity and organofacies characteristics when comparing respective oils from different basins.

Introduction

Heavy oil is generally characterized by high specific gravity, and high contents of heavy components. It is generally assumed that high viscosity heavy oils are resulted by alteration processes of crude oils by deep biosphere microbial activity (1). In addition, heavy oils can form at low levels of thermal maturity from sulfur-rich source rocks (2), or issue from abiotic alterations such as thermogenic-sulfate-reduction (TSR) (3). The more common alteration phenomenon by microbes, termed biodegradation, is well developed in the presence of nutrient-enriched waters and temperatures not exceeding 80-85degC (4; 5). The molecular alteration caused by microorganisms is accompanied by an increase in sulfur content, acidity, and viscosity, whereas API gravity and content of saturated hydrocarbons decreases. The biogenic alteration strongly impacts the economic potential of an oil accumulation because these properties affect both the oil value and oil recovery. However, biodegraded crude oil dominates the world’s petroleum reserves and so is of enormous economic relevance.

For the present study, we investigated 15 heavy oils from different basins in northern and southern America, and one oil sample from Asia using biomarker parameters obtained from gas chromatography - mass spectrometry (GC-MS) analysis. Additionally, data from stable carbon isotopes, SARA analysis, GC-FID and freezing-point depression were evaluated to characterize these oil samples. The aim of the study is to find correlations of geochemical characteristics with oil viscosity and density for heavy oils from different basins. On regional scale, oil viscosity, i.e. viscosity for oils from the same petroleum system, is a function of magnitude of alteration (6; 7; 8). The present study shows, however, that the degradation-viscosity correlation cannot be applied to compare heavy oils from different basins. Moreover, heavy oil viscosity/density is predominantly determined by original thermal oil maturity and organofacies characteristics when comparing respective oils from different basins. The results of the present study show that predictive models of oil viscosity using oil compositional characteristics require taking geochemical parameters on original maturity and organofacies into account.
Experimental

The sample set comprises 15 heavy oils from different reservoirs worldwide. Table 1 lists the samples, their geographical origin, the geological age of related source rock, their API gravity, and their dynamic viscosity / density at 50 degC and 80 degC.

All samples were sent for gas chromatography - mass spectrometry (GC-MS) analysis for biomarker studies. The aliphatic and aromatic fractions were evaluated for this study. Evaluation of biomarkers was carried out using the compound specific mass spectra (m/z).

Viscosity measurements were performed over a range of temperature from 10 to 200degC using a high-pressure, high-temperature (HPHT) capillary viscometer. The capillary viscometer is a closed system consisting of two, piston containing, HPHT cylinders connected by a smooth capillary coil. The set of capillary tubes used to generate the data for this report consisted of 0.31 to 7.0 m (1 - 20 ft) long stainless steel capillary tubes with an inner diameter ranging from 0.254 to 1.75 mm (0.010 - 0.069 in). The longer, smaller diameter tubes were used to measure lower viscosity values while the shorter, larger diameter tubes were used to measure higher viscosity values. The system set-up was rated for maximum operating conditions of 68.9 MPa (10,000 psia) and 200degC (392°F).

Prior to using charging, the entire system was cleaned with HyperSolve to remove any residual organic material and then purged with Nitrogen and evacuated to remove residual solvent and vapors. Warm heavy oil was then charged into the capillary tube from one of the pistonned cylinders. Once charged, the system was homogenized and the pressure and temperature adjusted to the test conditions. The pressure was always maintained above the saturation pressure to ensure the heavy oil remained liquid phase and hence, ensure there were no changes in the composition of the heavy oil due to evaporation of lighter components. Opposed piston pumps, connected to the hydraulic side of each cylinder, were used to create a smooth flow through the capillary tube. Differential pressure across the capillary tube was measured using a Validyne differential pressure transducer with an estimated accuracy of 0.01 psi. From the measured fluid flow rate and pressure drop, the viscosity was determined using the Hagen-Poiseuille relationship for laminar flow in tubes, namely:

\[ \mu = \frac{\Delta p}{8L} \frac{\pi r^4}{Q} = \frac{\Delta p}{Q} k \]

Where \( \mu \) is the fluid viscosity, \( \Delta p \) is the pressure drop across the capillary tube of length, L, and a radius, r, and Q is the volumetric flow rate. The tube constant \( k \) is determined by calibrating the viscometer using standards of known viscosity at test temperatures.

The flow rate was set to maintain an optimal differential pressure of 0.138 to 0.552 MPa (20 to 80 psi). Measurements were performed at three different average pressures. At each pressure, the viscosity was measured using 3 different flow rates. The average viscosity value from each pressure was then used to linearly extrapolate to atmospheric pressure to determine the dead oil viscosity at the defined temperature. The data was consistently linear with R2 values of 0.96 or better. It is the extrapolated viscosity values that are reported here.

Results and Discussion

Degradation – viscosity correlation

In-reservoir biodegradation has two main effects. First of all, it strongly reduces oil volumes in place, an effect which is to a large extent controlled by filling history, together with bulk biodegradation rates. Secondly, it leads to compositional alteration, resulting in a significant deterioration in crude oil. Considering the compositional changes, various classification systems describing different degradation stages have been proposed. The most commonly applied scheme is that suggested by Peters and Moldovan (9). This model describes a systematic and sequential removal of individual compound classes with increasing microbial degradation. This widely applied biodegradation model focuses on compositional changes during moderate to severe alteration stages; although the most significant decrease in oil quality (e.g. API gravity) takes place during depletion of volumetrically relevant compounds during the early stages of biodegradation (4).

Table 2 shows the rank of biodegradation for the oils under study. These oils were classified based on biodegradation characteristics following the Peters/Moldowan scale from 1 (slight) to 4 (severe). Samples CAN 4, CAL 1, SAM 1, 3, 4 even exceed the biodegradation rank of 5 to 7 after this scale. Samples CAL 2 and CAM 1 show only a slight biodegradation (rank 1), based on this classification scheme.

It is well accepted that on reservoir-scale the API gravity, oil density and viscosity decrease with increasing rank of biodegradation, showing increasing viscosity/density with ongoing microbial alteration. This, however, cannot be confirmed on a trans-regional scale. When comparing rank of biodegradation for oils of different reservoirs versus viscosity or versus oil density (Figure 1), it gets clear that degree of biodegradation is not the principle parameter to characterize heavy oils in terms of these physical properties. Interestingly, only the oils from USA, which are related to the same source rock, show a clear trend of biodegradation rank and viscosity/density. It is observed in Figure 1 that on trans-regional-scale biodegradation rank and viscosity/density don’t show any trend among oils from different basins.

Similar systematic is found for the ratio of asphaltene/(asphaltenes + resins) versus kinematic viscosity (Figure 2). Previous studies show for Venezuelan heavy oils that the ratio of asphaltenes and resins decreases with increasing kinematic viscosity (10). Samples under study show a gross trend among the South American oils, as well as among the oils from the USA, but not for oils from different petroleum systems.

The limited correlation of oil viscosity with degradation characteristics for oils from different basins in Figures 1 and 2 might be in part related to oil mixing. Nonetheless, it suggests also that other parameters such as organofacies and oil maturity differentiate viscosity trends for oils from different basins.
Influence of oil mixing on viscosity

In the previous chapters we argued already that some studied heavy oils represent mixtures of oils. Samples SAM 3 and SAM 4 point to be charged by fresh, nondegraded oil (Table 2) based on the abundance of n-alkanes. Samples CAL 1-3 show evidence of mixing between biodegraded black and light oil. In addition, further samples show evidence of being mixtures of altered oils representing different rank of biodegradation or different thermal maturities (Table 2). Commonly, certain parameters using hopane distributions and diamondoid distributions are useful to determine occurrence and degree of oil mixing on reservoir scale (11; 12). These parameters have however limitations for comparing oils from different reservoirs and basins worldwide. However, Mesozoic heavy oils from southern America are well known to contain high abundance of diamondoids up on secondary charges of light oil or condensates (13).

Figure 3 shows a plot of the maturity parameter TA/(MA+TA) versus Σ C0-C2 alkyladamantanes (µg/L oil). The ratio for the aromatic steroids TA/(MA+TA) was calculated after Riol et al. (14). The re-charged oils from South America show highest abundance of diamondoids. Obviously, the viscosity of these oils is reduced by the magnitude of mixing, i.e. abundance of diamondoids. This shows that oil mixing is an unraveling important parameter for oil viscosity.

Molecular weight C30+ - viscosity correlation

The best correlation of chemical parameters to oil viscosity is observed for the molecular weight of the C30+ fraction obtained from freezing point depression (Figure 4). The molecular weight of C30+ shows a near logarithmic trend versus the oil viscosity. This also supports our observations from biomarker analysis, where we assumed that viscosity is controlled by oil maturity, oil mixing and organofacies characteristics. The molecular weight of the C30+ fraction is directly related to thermal maturity, source organofacies characteristics, degree of alteration, and related to the proportion of mixing. Interestingly, oils from southern America and northern America show different trends in Figure 4, pointing to organofacies dependency of measured molecular weights for these oils.

Conclusion

Correlations between the extent of biodegradation and oil viscosity are commonly observed in regional studies, but cannot be applied to a worldwide data set because of the effects of other post-generation processes (e.g., deasphalting), source-rock heterogeneity, or oil mixing.

On worldwide scale oil viscosity is mainly determined by the original oil maturity and organofacies characteristics. Although biomarker characteristics of heavy oils from different reservoirs do not show a direct correlation to oil viscosity, they can be used to help limit potential oil viscosity ranges based on maturity and organofacies characteristics.

Biomarker studies show promise as a method to predict the range of viscosity/density for individual reservoirs. For example, biomarkers can explain why some oil fields will never reach the viscosities and densities of others.

The geochemistry of oil samples can explain outliers and why in many cases trends in the physical data have been difficult to establish (i.e. mixing of oils).

References

12. WEI, Z., MOLDOWAN, M., PETERS, K.E., WANG, Y., XIANG, W., The abundance and distribution of diamondoids in biodegraded oils from the San Joaquin Valley: Implications for biodegradation of


Tables and Figures

Table 1: Sample ID, origin, source age, and physical properties of studied heavy oils.

<table>
<thead>
<tr>
<th>Sample ID</th>
<th>Geology</th>
<th>Source Age</th>
<th>API</th>
<th>Density (g/cm³)</th>
<th>Viscosity (cP)</th>
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</thead>
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<tr>
<td>CAN 1</td>
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<td>80-100</td>
<td>10.2</td>
<td>0.870</td>
<td>2150</td>
</tr>
<tr>
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<td>10.7</td>
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<td>2150</td>
</tr>
<tr>
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<td>10.8</td>
<td>0.874</td>
<td>2150</td>
</tr>
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<td>550</td>
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</table>

Figure 1: Biodegradation rank versus the dynamic viscosity at 80degC.

Figure 2: Ratio asphaltenes / (asphaltenes + resins) versus the kinematic viscosity at 80degC.

Table 2: Rank of biodegradation for the heavy oils following the Peters / Moldowan scale.
Figure 3: Maturity parameter $\frac{TA}{(MA + TA)}$ versus $\sum C0 - C2$ alkyladamantanes (µg/L oil).

Figure 4: The molecular weight of the C30+ fraction versus viscosity of related heavy oils.