



Heavy Oil and Super Heavy Oil Viscosity Measurement and Estimation: Getting Representative Samples

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Summary

Oil viscosity assessed from core samples can increase dramatically during core storage and the process of oil extraction from core. Accurate measurement of bitumen viscosity from core is crucial for targeting sweet spots, locating production wells, and developing an appropriate recovery strategy. Here we show that viscosity error may be due sample storage conditions, storage duration, bitumen extraction method, sample composition and contamination, type of viscometer and laboratory practices. The effects of oil evaporation are also discussed along with a method to normalize viscosity data collected over a number of years by using a storage time viscosity correction (STVC) for incorporation into a geological model for oil mobility mapping.

Introduction

Reservoir and reservoir fluid heterogeneities are ubiquitous in heavy oil and tar sand (HOTS) reservoirs and impact reservoir processes such as SAGD that depend on uniform oil mobility for optimal recovery. These natural variations can impact optimal recovery process design, well placement and field management. Thus, detailed and accurate mapping of in-reservoir live oil mobility based on both high resolution core analysis (absolute and relative permeability) and viscosity logs is crucial for effective exploration and design/optimization of production strategies especially in biodegraded heavy oil and bitumen reservoirs. Traditional bitumen exploration and production strategies rely on characterization of reservoir properties and fluid saturations and often dead- oil viscosities and industry's confidence in these measurement methods, the measured values themselves, and application to in situ live oil data. Recently, many operators have been concerned about the reproducibility of the dead oil viscosity data and whether values representative or at least correlative to subsurface viscosities are being obtained.

Heavy oil and bitumen producers often find that viscosity data from the same reservoir, same well and/or same sample over time have a wide range of values. These may be related to natural petroleum heterogeneity in the reservoir and accessing different parts of the reservoir. Many controlled inter-laboratory comparisons have revealed significant variability in viscosity determinations from stored core material and produced fluids (Erno et al., 1991; Miller et al., 2006). This variability is a function primarily of sample contamination by water or solids, storage conditions and duration of time from core collection to oil analysis, oil extraction method, extrapolation to reservoir temperature, sample contamination, and correction to live oil values. An understanding of the key controls on dead oil viscosity measurement and methods for correction of existing data to minimize data "noise" are needed to ensure accurate resource

assessment as well as accurate calibration data for either geophysical (e.g., NMR) or geochemical prediction of *in situ* oil mobility across heavy oil and bitumen reservoirs.

Here we review some of the controls on dead oil viscosity of heavy oil and bitumen and present the results of a series of experiments to identify some of pitfalls of obtaining representative, reliable and accurate dead oil viscosity measurements. We also present best practice protocols to measure heavy oil viscosity and a correction methodology for core storage effects on measured viscosity.

Examples

A suite of laboratory experiments was conducted on reservoir core samples containing bitumen to evaluate the impact of storage conditions, oil extraction method, sample contamination, measurement or viscometer effects and extrapolation of measured data to different temperatures.

Volatilization of light ends during sample storage, handling, extraction and cleaning significantly affect the measured viscosity of heavy oils and bitumen. Core stored frozen loses light end hydrocarbons (e.g., alkylmethylcyclohexanes, alkylbenzenes and alkyltoluenes) with time due to diffusion and volatilization into the freezer causing an increase in bitumen viscosity by a factor of 2 or 3 after 1 year. However, the relative vertical viscosity variation along the core is maintained (Figure 1). Samples left at ambient conditions for even two months show dramatic increases in dead oil viscosity. For dead oil viscosity measurements, consistency in sample handling to minimize volatilization of these compounds is crucial to provide the most representative sample and viscosity measurement closest to *in situ* values.

The method to extract oil from the core sample can also alter bitumen properties and thereby affect measured viscosity. Centrifugation of core has been shown to volatilize light end hydrocarbons (e.g., alkylmethylcyclohexanes) to varying degrees depending on storage time, and level of biodegradation of the oil resulting in associated increases of viscosity values. Extensive testing indicates that chemically, oils recovered by centrifugation, compaction and solvent extraction are very comparable in C_{12+} hydrocarbon fraction. Compaction based bitumen extraction systems for core appear to retain light ends more effectively than centrifuge recovered oils and thus provide viscosity data more representative of unaltered bitumen.

Experiments investigating contamination of bitumen samples show that even small quantities of dispersed water and reservoir solids can significantly increase measured viscosity and add to the variability of these data. The dependence of viscosity on the mass of solids may be linear above 0.25 wt.%. Many producers report 2-5 wt.% solids content in cold produced heavy oils so these extracted samples may contain comparable amounts resulting in a viscosity increase by a factor between 1.5 and 2. This is especially the case with cold produced heavy oil which often forms oil-water emulsions. The viscosity of a cold-produced sample may vary by an order of magnitude simply because of the water content given an oil of identical hydrocarbon composition. Further study is required to routinely determine the amount of and in what form water and solids exist in a crude oil sample.

Clearly errors in viscosity data will be present in any large datasets collected over a period of time and it is likely that individual data may be inconsistent by up to order of magnitude levels (30 to 80% error) in the worst cases. Many legacy data reflect variable storage histories and bitumen recovery at many different times after drilling. To compare these data across a biodegraded oil field, a method to correct oil viscosities of stored core to the equivalent dead oil viscosity at drilling time has been developed and called the storage time viscosity correction (STVC). The best algorithm for the STVC varies with the natural logarithm of storage time assuming binary end member mixing of light end and heavy end fraction viscosities and is consistent with published algorithms of mass transport via diffusion through a polymer and oil spill evaporation. This method was used to estimate the retained light end fraction of the oil at a reference time and thus estimate viscosity at a constant epoch facilitating more homogenous datasets. The correction curve applied to a data set spanning 4 years provided adequate estimates of drilling time viscosity compared to values measured nearby on fresh core.

	Well A	Well B	Description
<i>Drill Date</i>	15-Jan-06	05-Feb-06	<i>Reservoir cored</i>
<i>Sampled</i>	23-Aug-06	20-Jul-06	<i>subsample from frozen core</i>
<i>1st Extraction</i>	15-Sep-06	09-Sep-06	<i>mechanical extraction</i>
<i>2nd Extraction</i>	14-Sep-07	13-Sep-07	<i>mechanical extraction</i>
<i>3rd Extraction</i>	05-Dec-07	07-Dec-07	<i>mechanical extraction</i>
<i>Storage time</i>	8.0 months	7.1 months	<i>frozen unwrapped</i>
<i>Storage time</i>	12.7 months	13.8 months	<i>frozen foil wrapped/bagged</i>
<i>Storage time</i>	2.7 months	2.8 months	<i>thawed foil wrapped/bagged</i>
<i>Storage time</i>	15.4 months	16.6 months	<i>Total from sampling date</i>
<i>Storage time</i>	22.7 months	22.0 months	<i>Total from drill date</i>

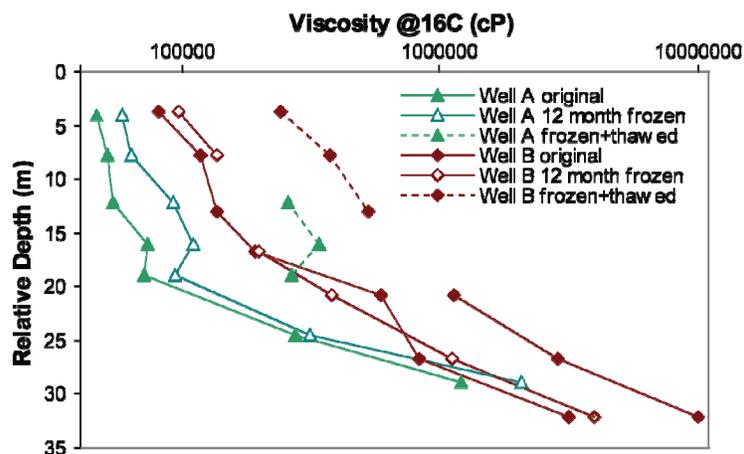


Figure 1: Dates and storage duration for core storage experiment and the 16°C viscosity gradients with depth for each well at the three measurement points of the experiment.

Conclusions

Measured viscosity is a function of not only intrinsic oil properties (source rock) and in reservoir alteration, but also the storage conditions and duration of time from core collection to oil analysis and sample contamination and lab protocols. Volatilization of the light end fractions of the oil during sample storage, handling, extraction and cleaning most significantly affect measured viscosity of heavy oils and bitumen. Oil extraction from stored core by compaction methods preserves light ends in the oil and minimizes contamination of the extracted oil sample with water or solids to a much greater degree than centrifuge extracted oils, which show volatilization of light end hydrocarbons to varying degrees and associated increases in viscosity values. Entrainment of even small quantities of water and clay in extracted oils can increase viscosity significantly (20% to an order of magnitude) and add to the variability of these data. For dead oils, consistency in sample handling to minimize volatilization of the viscosity controlling compounds is crucial to measuring the most representative dead oil viscosity values. Storage time viscosity correction (STVC) methods are simple to apply to viscosity data determined from stored core and should enable field wide viscosity data comparison for field development and management decision making. Sampling and viscosity measurement protocols for bitumen programs need to be revised to provide representative samples of subsurface reservoir fluids adequate for development decision making and field production management over the life time of a producing field.

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