

IN-SITU VISCOSITY USING LOW FIELD NMR: A FIELD CASE STUDY

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ABSTRACT

Low field nuclear magnetic resonance has been demonstrated to hold great potential as a tool for performing in-situ viscosity predictions. Previous experience has shown that low field NMR signals can be related to fluid viscosity, including high viscosity fluids like bitumen. A bulk liquid NMR model was developed that can make order of magnitude viscosity predictions for a wide range of samples from different fields in Alberta. The model can be tuned for individual oil fields to yield quantitative viscosity predictions with temperature. The same model has also been extended to predict viscosity of bitumen solvent mixtures.

The present work details a series of laboratory measurements performed for specific wells in a heavy oil reservoir. NMR measurements were initially performed on core samples. The constituent heavy oil was later removed from the core and its viscosity was measured both with NMR and with conventional methods. The in-situ viscosity of the reservoir was then predicted. From the laboratory and field NMR measurements a viscosity distribution “log” with depth was identified. The paper describes the algorithm followed and shows how such tests can be used to calibrate NMR logging data with respect to viscosity.

INTRODUCTION

Several countries in the world have oil reserves in the form of heavy oil and bitumen reservoirs [1,2]. Canada in particular contains significant proven reserves from our oil sands in northern Alberta, and one of the largest resource bases in the world. Heavy oil and bitumen is characterized by high viscosity values and density similar to or greater than that of water. The high oil viscosity is the single greatest impediment to the successful recovery of this oil, and the viscosity is directly related to both the technical success of any chosen recovery scheme and the economic value of the oil. As a result, oil viscosity information is key when estimating reserves and developing recovery options from heavy oil and bitumen formations. In order to measure viscosity, samples of oil are either recovered from the wellhead, or core samples are taken during initial drilling of exploratory wells. Oil is extracted from these core samples and its viscosity is measured using laboratory cone and plate viscometer apparatuses.

The difficulty in laboratory measurements from wellhead oil samples is that the oil may be contaminated by diluents or drilling fluid [3], or may contain significant emulsified water from thermal EOR methods. As a result, samples taken from the wellhead must be analyzed carefully in order to ensure that the viscosity values obtained are truly representative of the in-situ fluid properties. Extraction of heavy oil or bitumen from core samples can be an expensive process, and enough samples have to be measured in order to track possible oil viscosity changes with depth or areal location in the reservoir. If oil viscosity information could be extracted in-situ while logging, this would be very valuable to companies seeking to understand their reservoirs.

Low field nuclear magnetic resonance (NMR) technology has great potential to be used for measuring in-situ oil viscosity. Fundamental research with NMR [4] has shown that the spectra of bulk fluids can be used to provide information about the fluid viscosity, and conventional oil NMR viscosity correlations have been well documented in the literature [5-7]. New models have recently been developed to include heavy oil and bitumen viscosity ranges [8-10], and can be used to provide order of magnitude oil viscosity estimates for a wide range of fluid viscosities. These models were developed using bulk oil samples, for samples ranging from 1 cP (mPa·s) to over 3 000 000 cP.

The goal of using NMR for measuring oil viscosity is that these measurements could theoretically be made in-situ using an NMR logging tool. Most major service companies have such tools and can offer NMR logs as part of their suite of other logging services. NMR logs would measure the signal from oil and water found close to the wellbore, thus if the oil signal could be de-convoluted accurately and related to the oil viscosity as it is in bulk fluid NMR measurements, then oil viscosity could be estimated at different locations and depths throughout the reservoir. Previous work has focused on this oil peak de-convolution for the purpose of measuring oil viscosity, and viscosity predictions have successfully been made for a range of different viscosity samples with order of magnitude accuracy [11].

In this paper, a case study is presented for a single reservoir in northern Alberta. Core samples were taken and brought to our laboratory, where the heavy oil was removed and its viscosity was measured. NMR measurements of the bulk and in-situ fluids were also made, and the general NMR oil viscosity model has been tuned for this specific reservoir. The in-situ oil signal is then de-convoluted using the methods developed previously [11] and in-situ oil viscosity estimates are made.

RESERVOIR CASE STUDY

The reservoir studied in this paper is an unconsolidated sand heavy oil field in the Athabasca region of northern Alberta. Nineteen core samples were taken from three wells at various depths in the field, and the oil was extracted from the ores using a high-speed centrifuge. Figure 1 is an example NMR spectrum of one of the extracted heavy oil samples. It can be seen that the oil spectrum consists of a broad, fast relaxing peak that occurs under 10 ms and has an average relaxation time on the logarithmic scale of

the x-axis of close to 1 ms. There is very little signal beyond this first peak, indicating that the extraction technique has not led to the production of a significant fraction of water emulsified in the oil. This is an important validation, as it has been shown that when the emulsified water fraction is greater than around 12% of the total liquid mass, the measured viscosity is higher than the actual constituent oil viscosity [9]. For samples containing only a small emulsified water fraction, the additional increase in measured viscosity due to this emulsified water is negligible [9,12]. Of the nineteen oil samples extracted, the highest water content as determined by NMR was only 3.3%, and most samples had under 1% emulsified water. This means that the oil viscosities measured in the laboratory were representative of the actual oil and not an O/W emulsion.

Viscosity Measurements

Oil viscosity was measured in the laboratory using a HAAKE Rheostress[®] RS150 control stress cone and plate rheometer. The plate has a diameter of 35 mm, and the cone angle is 1°. This rheometer was used because it is capable of measuring extremely high fluid viscosity values. The viscosity measurement steadily increases shear stress such that the measured shear rate is above 0.1 s⁻¹ (the lower limit of shear rate for this machine) and does not exceed 2 – 3 s⁻¹. Higher values of shear rate could not be measured in order to avoid sample loss from the system during the measurement. The viscosity measurement consisted of linearly increasing shear stress and measuring the resulting shear rate. Ten data points were measured, and viscosity is the slope of the shear stress – shear rate line. For all samples tested, the slope was constant, meaning that the fluids are Newtonian and viscosity is not a function of shear rate [13].

The HAAKE rheometer heats the oil sample electrically, and therefore temperature can be maintained constant during a measurement to an accuracy of ±0.1°C of the set point. Unfortunately, the rheometer currently does not have cooling ability, therefore samples can only be measured at room temperature (25°C) and higher. In order to determine its value at the reservoir temperature (17°C), viscosity was measured at five temperatures: 25°C, 30°C, 35°C, 40°C and 50°C, and then extrapolated back to 17°C using an exponential Arrhenius-type function [10,13].

Figure 2 shows the oil viscosity at 17°C plotted against the subsea depth from which the samples were taken. The depths in this figure have been normalized to the top depth in order to protect the confidentiality of the actual field. As depth increases in the reservoir, the measured oil viscosity generally tends to increase as well. The measured dead oil viscosity values varied widely (10 200 cP to 276 000 cP) over the 45 m depth. This figure shows that it is possible for viscosity to vary substantially with depth even within a single field, and illustrates the need for in-situ viscosity estimation. Such viscosity variation with depth has also been observed by other researchers [14].

NMR Measurements

NMR measurements were taken of the bulk oils and oil sands (in-situ oil and water) for all nineteen samples. The machine used was a Corespec 1000TM low field NMR

relaxometer, which was built by the Numar Corporation. As with the HAAKE rheometer, the NMR machine is able to heat samples for measurements at elevated temperatures, but it has no cooling ability. Therefore, measurements were made at an elevated temperature of 30°C, which is the standard temperature for this machine. Initially, samples were placed at room temperature into the machine, allowed to equilibrate, and then an NMR measurement was performed. The parameters used are shown in Table 1. It is important to note that the low emulsified water content was measured using the parameters in the first column (30°C), which has a recovery time long enough to capture the signal even from water in large emulsion droplets.

Once it was shown that the emulsified water fraction was low and did not contribute to the high measured oil viscosities, oils and oil sands were measured at the second set of parameters in Table 1. This parameter choice reduces the recovery time between trains, greatly reducing the experimental time. Oil samples were measured at reservoir temperature by cooling the samples to 13°C and placing them into the NMR. The fast measurement took around 6.8 minutes, at which point the sample temperatures were around 19°C. The log-mean temperature difference calculated was approximately 4°C, leading to an average experimental temperature of 17°C, which is what was desired.

DEVELOPMENT OF NMR BULK OIL VISCOSITY MODEL

Conventional NMR theory gives the equation for NMR bulk relaxation as [7]:

$$\frac{1}{T_{2B}} \propto \frac{\mu}{T} \quad (1)$$

Where $1/T_{2B}$ = the bulk relaxation rate

μ = fluid viscosity

T = absolute temperature (K).

This equation states that as viscosity increases, the bulk relaxation rate will also increase linearly, leading to smaller values of measured transverse relaxation time, T_2 . As a result, most NMR models in the literature [5,6,15] relate viscosity to the NMR relaxation time. Since oil consists of many components, relaxation time in these NMR correlations is usually the geometric mean relaxation time, T_{2gm} .

For higher viscosity samples like heavy oil and bitumen, the relationship between T_{2gm} and viscosity is no longer as linear. In fact, for very high viscosity samples, relaxation is so fast that the fluid is relaxing at the limits of what low field NMR can measure, and T_{2gm} changes only marginally with changes in viscosity [8-10]. For these fast-relaxing components, a portion of the signal also relaxes too quickly to be measured with conventional low field NMR tools [10,16,17]. Therefore, high viscosity fluids also have relatively lower amplitudes than lower viscosity fluids, meaning that the measurable oil

amplitude is another parameter that can be related to oil viscosity. As a result, a new model was developed that relates oil viscosity to both parameters [8-10]:

$$\mu = \frac{\alpha}{(\text{RHI})^\beta T_{2\text{gm}}} \quad (2)$$

Where RHI = the oil relative hydrogen index

$T_{2\text{gm}}$ = the oil geometric mean relaxation time (ms)

α , β = empirical fitting constants.

In Equation 2, RHI is the oil amplitude per unit mass, referenced to the amplitude per unit mass of water at the same temperature. The explanation for the form of this model has been described elsewhere [10]. For a wide suite of conventional oils, heavy oils and bitumen from different fields in Alberta, general values of α and β are 1150 and 4.55, respectively. It should be noted that there is scatter in correlations of both $T_{2\text{gm}}$ and RHI with oil viscosity, thus the general NMR viscosity model can only provide estimates of viscosity within order of magnitude accuracy. In order to have more accurate predictions measured viscosity data have to be used to tune the NMR model for individual formations. For this case study, the general NMR model led to viscosity predictions that correlated very strongly with measured viscosity at 17°C, but were consistently quite low. Tuning the model for this formation yielded updated values of α and β of 4073 and 5.03, respectively. Figure 3 shows the viscosity predictions made using the tuned viscosity model, plotted against measured viscosity at 17°C. With tuning, there is a very high degree of correlation between the measured and predicted viscosity values, as evidenced by the high R^2 value shown in Figure 3. Therefore, the general NMR viscosity model can be tuned to provide accurate viscosity estimates for this specific formation.

IN-SITU VISCOSITY MEASUREMENTS

In order to predict in-situ viscosity using this tuned NMR model, the parameters $T_{2\text{gm}}$ and RHI have to be predicted in-situ. This means that the heavy oil and water signals first have to be de-convoluted from the in-situ liquid spectrum, which is not a trivial task. Heavy oil relaxes quickly through bulk relaxation, and it is not intuitively clear whether the effect of the porous medium leads to enhanced surface relaxation. Water in porous media also relaxes faster due to surface relaxation effects, and when there are clays present this leads to enhanced relaxation effects [18,19]. Thus, surface bound water due to the presence of clays can have relaxation times that are similar to bulk heavy oil peaks [20]. The spectra of heavy oil and water in unconsolidated porous media are therefore much more complex to separate than the spectrum of a mixture of these liquids in bulk.

Figure 4 shows an example of an oil sand spectrum plotted along with the spectrum of its constituent oil, that was removed via centrifuging. The bulk oil spectrum occurs at approximately the same position as the first, fast-relaxing peak of the oil sand. Therefore, it can be inferred that for high viscosity heavy oil, bulk relaxation occurs so

quickly that any effects of the oil being inside a porous medium are negligible. If the oil spectrum could be de-convoluted from the in-situ water also in the oil sand, then its NMR properties (RHI and T_{2gm}) could then be related to its viscosity using the tuned bulk oil viscosity model.

Due to the presence of clay bound water, it would be incorrect to assign the entire first peak of the in-situ liquid spectrum to be the signal from oil [18,20]. Doing so would lead to oil T_{2gm} estimates that are consistently higher than the bulk oil values, which has no physical meaning. In order to properly determine the in-situ oil response, the presence of fast-relaxing clay bound water in the first in-situ peak must be accounted for. A simple oil de-convolution algorithm has previously been developed [11] and tested on a limited range of oil sand and bulk oil samples. This approach is a simple numerical approximation designed to estimate the location of overlapping gaussian oil and clay-bound water peaks in the oil sand spectrum. In this approach, slopes and second derivatives are numerically calculated for the first peak of the oil sand spectrum. At the point where the second derivative changes from being negative to positive, this is the inflection point indicating that the first peak is beginning to taper off. The oil signal is taken to be the entire amplitude of the first peak up to the inflection point, and then the oil is linearly reduced to zero amplitude over the next three T_2 steps (i.e. oil is taken to be 75%, 50% and 25% of the amplitude, and 0% thereafter). Figure 5 shows such a de-convolution for one of the samples in this case study.

The proposed de-convolution approach separates the first peak in the oil sand spectrum into two components: an oil peak and another peak that can be understood to be clay-bound water. This second peak generally begins at a value close to 1 ms, which is similar to where clay peaks have been seen in other work [18-20]. The oil peak also appears roughly symmetrical on the log scale of the NMR spectrum, which is what has been observed for bulk oil spectra. Once the oil peak has been de-convoluted, its geometric average relaxation time can be calculated. Figure 6 compares the in-situ oil T_{2gm} to the bulk values for the samples in this case study. There is some scatter present between the two, however the in-situ de-convolution generally seems to lead to in-situ T_{2gm} estimations that are close to the bulk values. It may appear from Figure 6 that the de-convolution algorithm is leading to in-situ T_{2gm} values that tend to be less than the bulk oil values, however in other work [11] this was not observed.

The other NMR parameter that has to be calculated for viscosity predictions is the oil RHI value. As mentioned previously, RHI is the oil amplitude per unit mass of oil, divided by the amplitude per unit mass of water at the same temperature. During logging the oil mass is not known, therefore RHI cannot be determined simply the way it can in bulk samples. However, RHI and T_{2gm} can be related to one another through the oil viscosity. As viscosity increases, both T_{2gm} and RHI decrease, meaning that the two parameters are not truly independent. Therefore, if they are plotted against one another, RHI can be predicted based on the oil T_{2gm} . Figure 7 shows the in-situ oil T_{2gm} plotted against the oil RHI values measured in the bulk oil samples. As expected, a strong

monotonic correlation is observed between oil relaxation time and RHI, and this can be used to predict the oil RHI using the de-convoluted oil T_{2gm} . The in-situ viscosity and bulk oil viscosity values are compared against measured viscosity in Figure 8.

The in-situ viscosity estimates still correlate well with measured viscosity, as evidenced by the high R^2 fit (0.9599). There is considerably more scatter in the in-situ viscosity predictions, however, meaning that the accuracy of the in-situ predictions is not as good as the bulk oil model. The average percentage error in the in-situ viscosity calculation is 33%, compared to only 12% for the bulk oil model. The additional error is mainly due to inaccuracies in the oil signal de-convolution, which lead to the scatter in Figure 6. With more samples, perhaps the oil peak de-convolution algorithm can be refined and the in-situ oil viscosity predictions will be improved. For logging tool applications, however, the proposed method is capable of predicting general viscosity ranges.

At this point it is important to note that the proposed method for in-situ viscosity predicts RHI based on the oil T_{2gm} , therefore what this really shows is a non-linear correlation between oil viscosity and NMR relaxation time. The relationship between T_{2gm} and viscosity changes in different ranges of oil viscosity, thus measuring RHI for bulk oils allows the model to be tuned for this non-linearity. The relationship between RHI and T_{2gm} is not constant in all ranges of viscosity, which explains why the general NMR model is only order of magnitude accurate. Also, if RHI and T_{2gm} are plotted against one another for oil samples from many different fields, the resulting correlation has a lot of scatter [21], making it difficult to predict RHI accurately. Within a single field, however, the relationship between these parameters is much clearer, allowing for in-situ viscosity estimates to be made.

CONCLUSIONS

NMR and viscosity measurements have been performed for nineteen core samples from a single field in northern Alberta. This core data was used to develop a tuned bulk oil viscosity model for these samples at reservoir temperature, which relates viscosity to oil T_{2gm} and RHI. In order to predict these parameters in-situ, the oil and water signals have to be separated in the spectra. A simple numerical de-convolution approach has been used to estimate the in-situ oil signal, and leads to in-situ oil T_{2gm} predictions that are similar to their bulk values. In-situ RHI can then be determined based on the oil T_{2gm} values, thus the tuned bulk oil model can also be used for in-situ viscosity estimates. In-situ viscosity predictions are less accurate than bulk oil predictions, mainly due to scatter between bulk and in-situ oil relaxation times. However, the model is accurate enough that the viscosity range can be predicted in-situ, which allows for an understanding of how viscosity varies with depth in any given field. This is useful information for companies seeking to understand how to properly produce their reservoirs, and these measurements can be performed during the initial logging of the reservoir.

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NOMENCLATURE

NMR	Nuclear magnetic resonance
RHI	Oil amplitude per unit mass, divided by water amplitude per unit mass
T	Absolute temperature (K)
T _{2B}	Bulk relaxation time (ms)
T _{2gm}	Geometric mean relaxation time (ms)
α	Empirical fitting constant
β	Empirical fitting constant
μ	Fluid viscosity (cP)

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Table 1: NMR parameters used for measuring bulk oils and oil sand samples

	30°C Measurement	Res. Temperature
TE (ms)	0.3	0.3
Number of echoes	5000	5000
Recovery time (ms)	15,000	2600
Number of trains	49	49

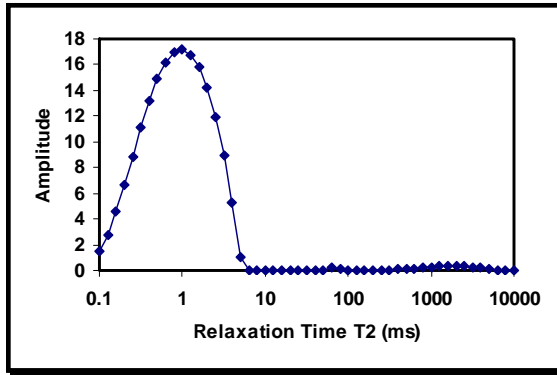


Figure 1. NMR spectrum of an extracted heavy oil sample, measured at 17°C

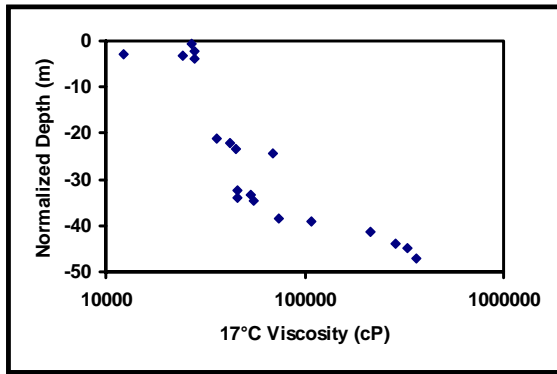


Figure 2. Measured bulk oil viscosity at reservoir temperature as a function of depth

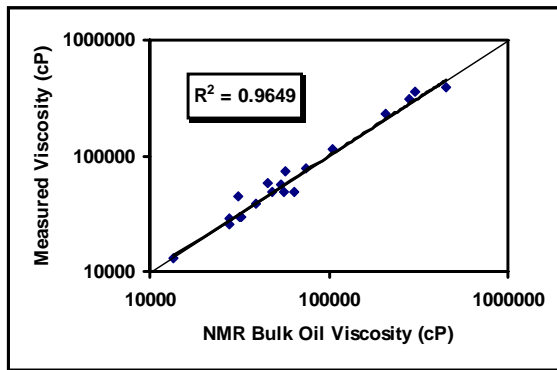


Figure 3. Tuned bulk oil model viscosity predictions

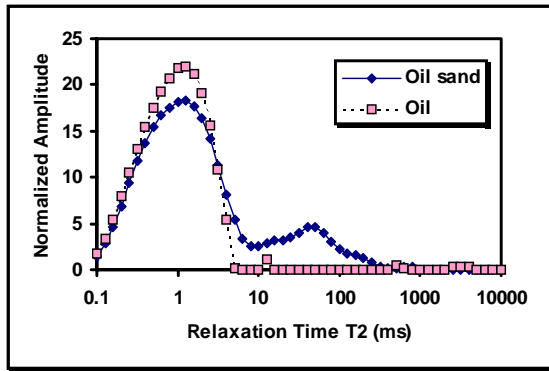


Figure 4. Bulk oil spectrum and oil sand spectrum containing same oil plus water

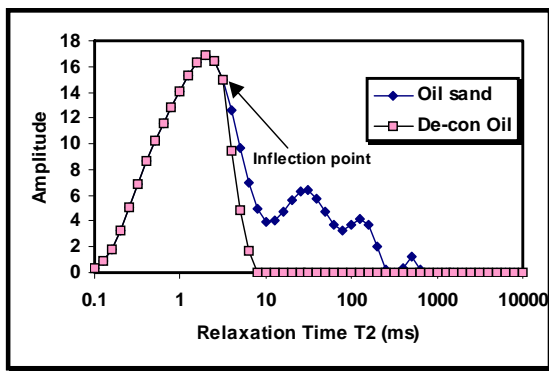


Figure 5. Proposed de-convolution of the in-situ oil signal

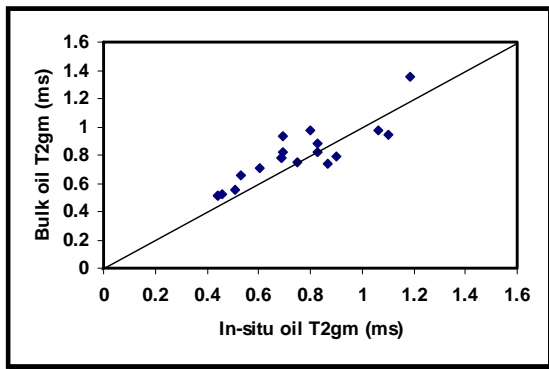


Figure 6. In-situ oil relaxation time compared to bulk values

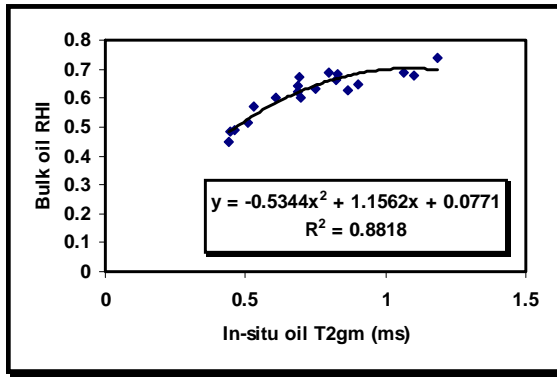


Figure 7. RHI predictive correlation for the case study field

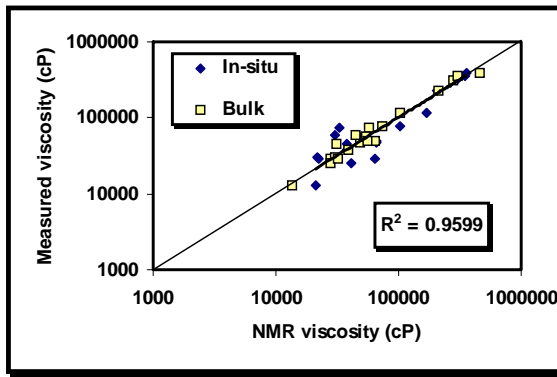


Figure 8. In-situ and bulk NMR viscosity predictions