

Heavy Oil Reservoir Characterization Using Low Field NMR

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Summary

In development of heavy oil and bitumen formations, proper reservoir characterization is key to the successful recovery of this resource. Conventional measurements of oil viscosity and fluid content are time-consuming and expensive to perform, and may vary considerably in the reservoir. This study proposes the use of low field NMR technology to characterize these reservoirs. It is demonstrated that in a single measurement, information regarding oil viscosity, fluid content and the nature of the sand can all be potentially obtained. NMR core analysis predictions can be made with a high degree of accuracy, but logging tool predictions are still only capable of showing trends in fluid properties.

Introduction

Canada has significant heavy oil and bitumen resources, mainly in northern Alberta and Saskatchewan. With the decline in conventional oil reserves, coupled with regional instabilities and a higher demand for oil worldwide, interest is now shifting rapidly to the production of this heavy oil. Heavy oil and bitumen are characterized by having very high viscosity (100 mPa·s to over 1,000,000 mPa·s) at reservoir conditions, and density that is similar to water. The high oil viscosity is one of the greatest impediments to the successful recovery of this oil, therefore knowledge of oil viscosity is key to the technical and economic success of any EOR scheme attempted. In addition, information regarding oil content and an indication of the fines content in the sand can provide a higher level of understanding regarding recovery and flow in porous media. This will be true for both *in-situ* recovery methods and for oil sands mining characterization.

Ideally, if information regarding the rock and/or fluid properties could be obtained at the initial reservoir characterization stage, as in a logging tool, this would avoid errors involving sample handling¹ and expensive laboratory testing. Additionally, oil properties may change considerably in the reservoir^{2,3}, thus it is valuable to obtain the proper measurements in the actual reservoir

conditions. In the past, low field NMR technology has been shown to have considerable potential for measurements of *in-situ* oil viscosity^{4,5} and to estimate the oil and water content in oil sands mining samples⁶⁻⁸. In this study, data is provided for core and logging tool NMR measurements made in several different fields in Alberta, and concepts are addressed regarding how information about the rock and fluid properties can be obtained using NMR technology.

Methodology

NMR measures the response from fluids in porous media, therefore the signal comes only from the oil and water, and not from the rock itself. However, the nature of the fluid relaxation can be used to provide an indication of either the fluid properties (i.e. the viscosity) or the size of the pores in which the fluids are located. Figure 1 shows an example of water in different sizes of pores. As water is constrained in smaller pores, it consistently relaxes more quickly.

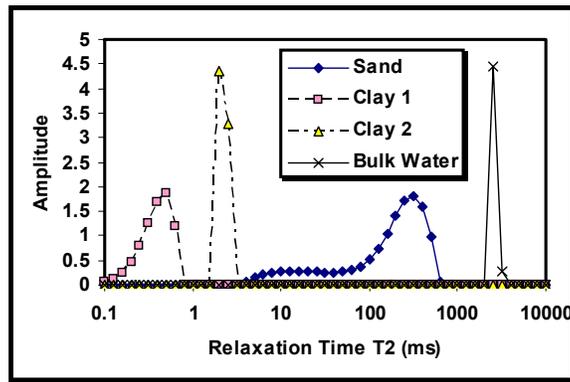


Figure 1: NMR spectra of water in sand and clay

Water alone is a low viscosity fluid, thus its bulk relaxation is slow, on the order of around 2000 ms. When the water is located in pores of varying size, the water T_2 distribution is essentially analogous to a pore size distribution, since surface relaxation is so much faster than the bulk relaxation of water. Heavy oil and bitumen, conversely, are highly viscous and therefore have very fast bulk relaxation times. Figure 2 compares the spectrum of a bulk sample of bitumen to its signal inside sand.

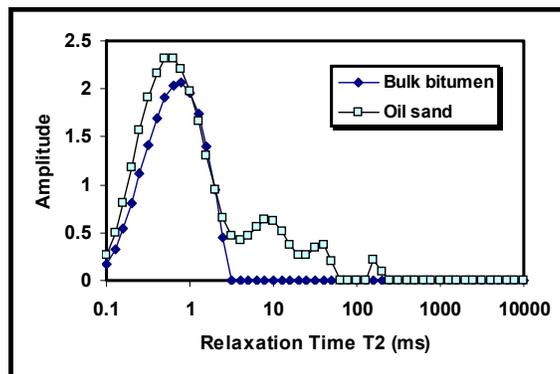


Figure 2: NMR spectrum of oil sand, compared to the bulk oil signal

Due to the high oil viscosity, the relaxation times for heavy oil and bitumen occur at approximately the same T_2 locations whether the fluid exists in bulk or in porous media. In the past, bulk heavy oil viscosity was related to the bitumen relaxation time and relative amplitude (RHI), as shown in the following model⁹:

$$\mu = \frac{\alpha}{(\text{RHI})^\beta T_{2\text{gm}}} \quad (1)$$

Where μ = the oil viscosity (mPa-s)
 RHI = the oil amplitude index, divided by the water amplitude index
 $T_{2\text{gm}}$ = the oil mean relaxation time (ms)
 α, β = empirical constants.

Models for viscosity can therefore be developed using bulk oil, and then if the parameters RHI and $T_{2\text{gm}}$ can be determined from the *in-situ* oil signal, then the *in-situ* oil viscosity can also be predicted^{4,5}. The oil $T_{2\text{gm}}$ is relatively straight-forward to determine, since the oil signal is not affected by the porous medium. In samples where there is not a significant amount of clay-bound water or water in films¹⁰, the signal in the first peak is mainly due to the oil and the oil $T_{2\text{gm}}$ value can be de-convoluted out of the oil sand signal^{4,5,7,8}.

The determination of the oil RHI is more problematic. RHI is a measure of the oil “amplitude index” normalized to the amplitude index of water. Amplitude index is the NMR amplitude per unit mass or volume, which is known in any NMR benchtop or logging tool. Values of oil RHI within the oil sand can be inferred through a non-linear function with the oil $T_{2\text{gm}}$ ^{5,7}, or could potentially be determined in NMR logging tools based on the under-prediction of the fluid porosity, compared to conventional porosity logs¹¹. Once the RHI value is known, then oil viscosity can be predicted using the bulk oil viscosity model. Additionally, if oil RHI is known, then this is a manner to convert the oil measured amplitude into a fluid mass or volume value. In this manner, NMR measurements can be used to provide both a measure of the oil viscosity and also the oil and water content in the reservoir. In shallow oil sand reservoirs or reservoirs with unknown brine salinity, this tool has potential to be extremely useful.

In this work, several case studies are presented that illustrate the potential for these measurements to be made in core and logging tool measurements.

Examples

Many oil sand spectra appear qualitatively similar to Figure 2: they are characterized by having a distinct fast-relaxing peak under 10 ms, which is mainly the contribution of the oil. From the oil signal, the $T_{2\text{gm}}$ value can be found and then the oil RHI can be predicted and used to evaluate both the oil viscosity and the oil content. In certain samples, however, where the oil content is low or clay content is high, the first peak cannot be easily de-convoluted. Figure 3 presents spectra for two oil samples of varying viscosity. Although the lower viscosity oil (as evidenced by the shifting peak to longer relaxation times, > 1 ms) will be easier to produce, the oil is located in sand that contains a high degree of fines. This is shown by the apparent “skewing” of the fast-relaxing peak. Therefore, while the lower viscosity oil is of a higher quality, the oil may still not be easy to produce due to poor flow conditions in the reservoir. Therefore, NMR provides a description not only of the fluid, but can also be used qualitatively to describe the sand permeability.

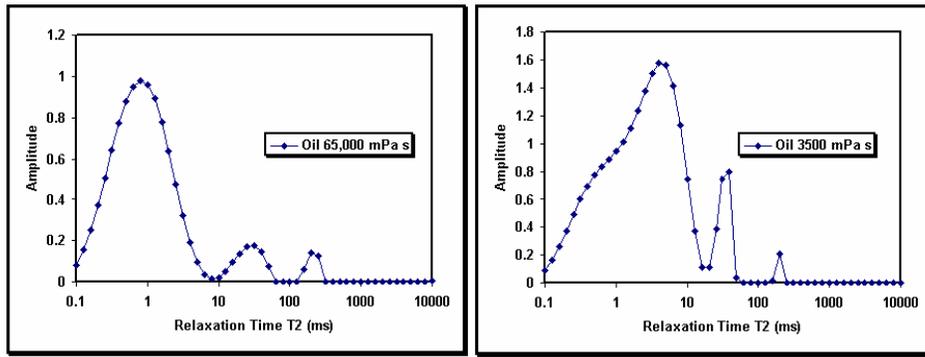


Figure 3: Oil sand spectra for oils of varying viscosity, in sand with varying fines content

When the degree of overlap between the oil and the water-saturated fine solids is high, this is evidence of either low oil saturation or high fines content. This will generate errors in both the viscosity predictions and the predictions of oil content. Figure 4 shows the NMR predictions made as a function of depth in a single well in the Athabasca region. The green zones are the core samples that have good spectra, similar to Figure 2. The other zones must be interpreted with a higher degree of caution.

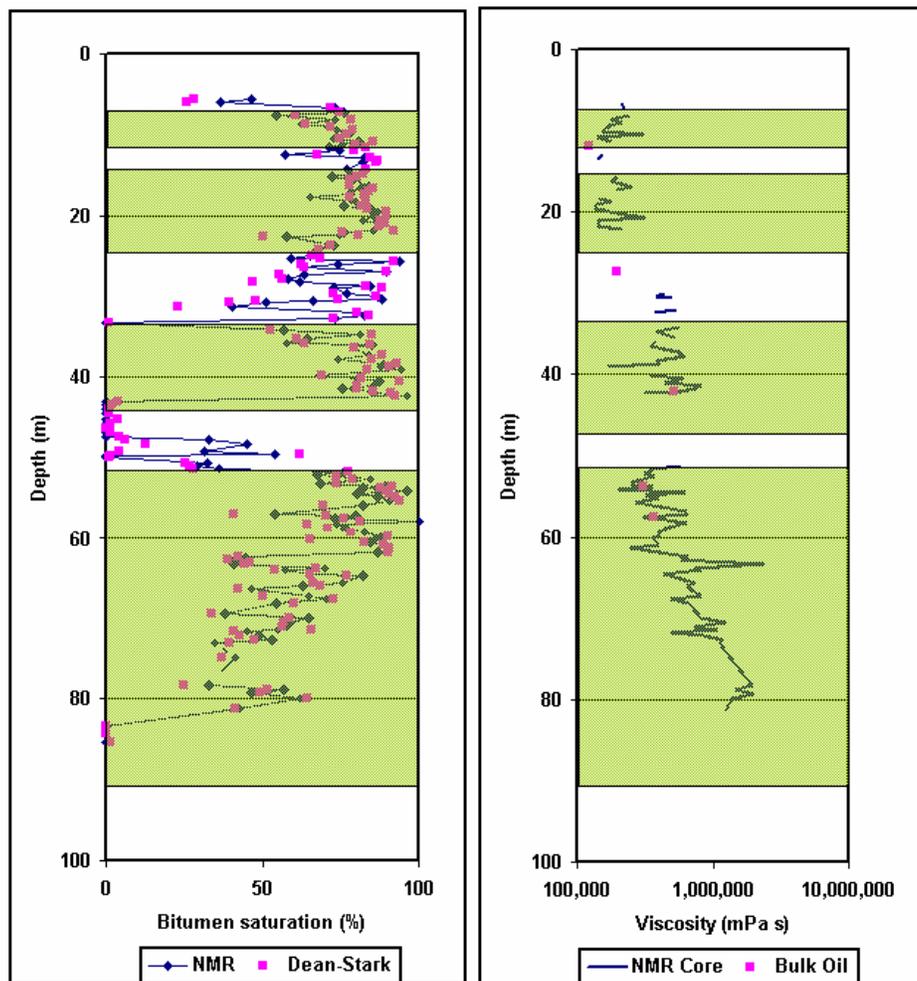


Figure 4: Predictions of bitumen saturation and viscosity from core samples in a single well

Finally, if comparisons are made against logging tool predictions, it is apparent that there is still a high degree of scattering in the logging tool spectra, as shown in Figure 5. This could be due to multiple causes, such as noisy measurements and different acquisition or spectra-generation parameters. NMR predictions from a logging tool can show trends in oil viscosity, but more work is still needed in this area.

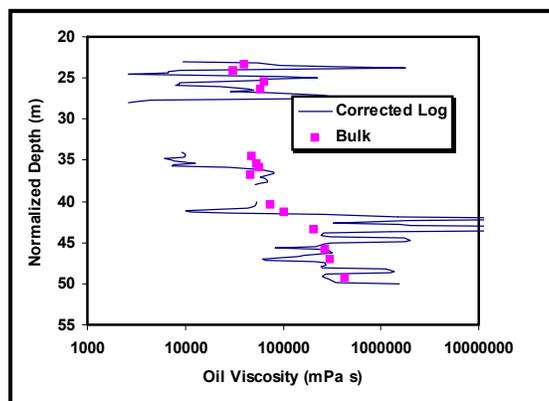


Figure 5: NMR core viscosity predictions vs. logging tool viscosity predictions

Conclusions

NMR shows great promise as a tool for characterizing heavy oil and bitumen reservoirs. Measurements can be indicative of oil viscosity, fluid content, and also fines content in the sand. Therefore, a considerable wealth of information can potentially be obtained in a single measurement. Core analysis predictions can be made to a very high degree of accuracy, however currently logging tool predictions can only be used to indicate general trends in oil properties.

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Reference Style (use Arial 9pt normal)

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