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Estimation of Fluid Properties Using NMR Correlations in Berea Rocks

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Abstract

Fluid viscosity is one of the most important parameters necessary to establish reservoir production and economic potential. Until the appearance of Nuclear Magnetic Resonance (NMR) techniques in the oil industry, oil viscosity determination was limited to laboratory tests and correlations with API gravity. Nuclear Magnetic Resonance response is the consequence of fluid properties, as viscosity and density, and its interactions with its surroundings. In water wet rocks, oil NMR behavior depends only on its properties, since it has not contact with the pore surface. However, the water attached to the surface has an effect on the global NMR signal. The technique used to overcome this situation is the NMR differential spectrum, which consists in implementing two different polarization times during NMR measurements, one that polarizes all present fluids and the other, which only polarizes the water. This technique has shown good results for sand reservoirs saturated with light oil, since the polarization time of light oil is much greater than the polarization time of water in sandstone. However, this technique cannot be used with confidence, in presence of heavier oil or in rocks where the water has greater polarization time, since both signals can be overlapped. This study is based on the idea of generating correlations to determine fluid properties through the use of mixed NMR signals of oil and water. In the study, we used Berea rocks to determine correlations for API gravity and oil viscosity vs. logarithmic average and 1st quartile of the NMR T2 distribution, for three different echo times (300, 600 and 1200 μs). These correlations were determined in a general form as function of the echo time for free fluids and in saturated samples. API gravity correlations for free fluids and fluids inside the porous media showed similar results, while viscosity results showed the need of a specific correlation for fluids inside the porous media. This work constitutes a preliminary step on the generation of correlations to determine fluid properties inside the porous media.

Introduction

Reservoir formation evaluation is based on estimation of properties as porosity, permeability and fluid saturation. These properties, together with fluid properties, as viscosity and density, are used in the determination of the reservoir productivity. Well logs have been successful in the determination of porosity and fluid saturation, however, determination of permeability, viscosity and fluid density are still limited to the use of correlations or laboratory studies.

Fluid viscosity is highly important on the determination of fluid mobility inside the reservoir, what defines the reservoir productivity index. On the other hand, knowledge of viscosity could be very useful, since several reservoirs present variability of oil viscosity of several magnitude orders along the well column. This situation makes difficult the identification of productive intervals, without the use of expensive methodologies as down hole fluid sampling.

Recently, service companies begin the commercialization of Nuclear Magnetic Resonance (NMR) tools, which measure magnetic relaxation of hydrogen nuclei of reservoir fluids. Magnetic relaxation of hydrogen nuclei is the consequence of fluid interaction with its surroundings and its intrinsic properties. Fluid interaction with its surroundings refers to magnetic relaxation due to contact with the pore surface, while intrinsic properties are referred to the effect of fluid properties, as density and viscosity, on magnetic relaxation. NMR relaxation signals have an exponential decay behavior, which is better described by a multiexponencial equation. This equation is formed by a serie of characteristics times with its correspondent weight. Weights are determined by an Inverse Laplace transform and the graphic representation of the weights against characteristic times constants, constitutes the NMR T2 distribution. T2 distributions are the base of rock and fluids studies through NMR.

In water wet rocks, oil NMR behavior depends only on its properties, since it has not contact with the pore surface. However, the water attached to the surface has an effect on the global NMR signal. The technique used to overcome this situation is the NMR differential spectrum, which consists in implementing two different polarization times during NMR measurements, one that polarizes all present fluids and the other, which only polarizes the water. This technique has shown satisfactory results for sand reservoirs saturated with light oil, since the polarization time of light oil is much greater than the polarization time of water in sandstone. However, this technique cannot be used with confidence in presence of heavier oil or in rocks where the water has greater polarization time, since both signals can be overlapped. This work is based on the idea of generating correlations to determine fluid properties through the use of mixed NMR signals of oil and water.

Experimental

As mentioned before, the objective of this study is to determine fluid viscosity and density through NMR measurements of fluids contented in the porous media. For this reason it is convenient to study the oil NMR response as free fluid and inside the porous media at irreducible water saturation. The general methodology consisted in first measuring conventional fluids properties, as well as conventional petrophysical properties of Berea rocks. This way all variables involved in the system are been monitored.

NMR measurement were made with a Maran Ultra[*] equipment to both free fluids and fluids in the porous media. Berea rocks were previously saturated with brine and then displaced with oils of different viscosity, until it reached irreducible water saturation. The water - oil saturated samples were measured in the NMR equipment. Free fluids and water – oil saturated Berea rocks were measured at three different echo times (300, 600 and 1200 µs).

T2 logarithmic average and the first quartile of the T2 distributions were calculated and correlated with fluids properties and constitute the results discussed below.

Results

In this section, results of correlations between NMR parameters and fluid properties (API gravity and viscosity) are discussed. Correlations for free fluids and for water – oil – Berea mixed system were determined and results are discussed separately. Additionally, a comparison between the two systems is made to assess the benefits of studying the mixed system.

Free fluids

Correlations between fluid properties and NMR parameters (T1, T2log, ln(T2log), Q1 and ln(Q1)) were determined for the three echo times used. Figure 1 shows correlation between API and T1 and, as expected from previous studies, the correlation has a high R^2 (0.92). Figure 2 shows the relation between viscosity and T1, showing also a good correlation factor but not as high as for API gravity ($R^2 = 0.87$). Figure 3 shows the correlation between API gravity vs. T2log and ln(T2log), both equations show a good relationship for this property ($R^2 > 0.90$). Figure 4 shows the same relation for the 1st quartile of the distribution (Q1). Note worthy that even tough the correlations using Q1 are as good as with T2log, it is possible to have better information about Q1 from logs than for T2log. This is because, it is well known that complete polarization of the sample is not always achieved during NMR logging, specially with light oils, making necessary to "predict" the signal for complete polarization. The correction is somehow good to estimate the value of the total amplitude. However, it not necessary correctly predicts the shape of the T2 distribution. This approach will produce errors in T2log calculation, while the 1st quartile (Q1) could be better determined, since it is the time when the cumulative signal reaches 25% of the total amplitude. Following this trend, figure 5 shows correlation for oil viscosity vs. T2log and Q1 with a R^2 greater than 0.83. Correlations were determined for the three echo times mentioned before, and results are summarized in the eight equations listed below. Figures for 600 µs and 1200 µs echo time are not shown, since they were very similar to the ones shown in this paper, which were determined at 300 µs echo time. Constants for each case are shown in table 1.

$$API = a \cdot T1^{b} \tag{1}$$

$$API = a \cdot T2\log^{b} \tag{2}$$

$$API = a \cdot \ln(T2\log) + b \tag{3}$$

$$API = a \cdot Q1^{b} \tag{4}$$

$$API = a \cdot \ln(Q1) + b \tag{5}$$

$$\mu = a \cdot T1^{b} \tag{6}$$

$$\mu = a \cdot T2\log^{b} \tag{7}$$

$$\mu = a \cdot Q1^{b} \tag{8}$$

Constants for each equation were plotted against echo time for the correlations with T2log and Q1 with correlation factors (R^2) greater than 99%. This analysis allows us to rewrite the above equations in the following echo time (TE) dependant correlations to estimate API and viscosity of free fluids.

$$API = (-0.0008 \cdot TE + 4.495) \cdot T2\log^{\left(2 \cdot 10^{-5} \cdot TE + 0.173\right)} \tag{9}$$

$$API = (0.0005 \cdot TE + 4.692) \cdot \ln(T2\log) + (-0.0063 \cdot TE - 20.854) \tag{10}$$

$$API = (-0.0012 \cdot TE + 5.638) \cdot Q1^{\left(2 \cdot 10^{-5} \cdot TE + 0.161\right)} \tag{11}$$

$$API = (0.0007 \cdot TE + 4.377) \cdot \ln(Q1) - (-0.0075 \cdot TE - 14.756) \tag{12}$$

$$\mu = \left(4523.8 \cdot TE + 5 \cdot 10^{5}\right) \cdot T2\log^{\left(-9 \cdot 10^{-5} \cdot TE - 1.014\right)} \tag{13}$$

$$\mu = (1291 \cdot TE + 74892) \cdot Q1^{(-0.0001 \cdot TE - 0.938)} \tag{14}$$

To verify the importance of having correlations which depend on the inter echo time (TE), a sensibility analysis was done. Figure 6 shows sensibility of equation 9 to variations of the inter echo time, in which it can be seen that variability of API estimated is not important. This behavior was also seen for equations 10, 11 and 12. However, the same conclusion is not achieved for viscosity equations. Figure 7 show sensibility

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Universal's system

analysis for equation 13, which shows that for oils with medium viscosity, changes in echo time can be important with up to 10 cp. of variation. These observations indicate that echo time is more relevant to estimate viscosity than API gravity, and should be taken into account in this kind of studies.

Fluids inside Berea Rocks

In this section the same analysis is done for the fluids in the chosen porous media, Berea rocks. Figure 8 shows T1 relation with API gravity with a very high R^2 (0.97) for the mixed system (oil at irreducible water saturation in Berea rocks). A good relation was also found for viscosity, which is shown in figure 9 reaching a R^2 of 0.95. Figure 10 shows also a good correlation for API gravity vs. T2log having a correlation factor greater than 0.94. This was similarly observed for the 1st quartile in figure 11. Finally, figure 12 shows results of oil viscosity vs. T2log and Q1, also indicating a high correlation factor for both NMR parameters (R^2>0.90).

As for free fluids, equations for each echo time were also determined and they have the same form as for free fluids (equations from 1 to 8). Constants are reported in table 2.

Comparing table 1 and 2 is easy to notice that values are very similar, so a comparison of correlations for free fluids vs. fluids in the mixed system was done. Figure 13 shows comparison of the API vs T2log correlations at 300 μs echo time for free fluids and the mixed system. As it can be seen, both correlations are extremely similar, with differences of 2.5 API maximum for light oils and 1 API for heavy oils, implying that the irreducible water signal is not affecting API estimation. In the case of viscosity (figure 14), both correlations are also similar, coinciding very well for low viscosity. However, variations observed for high viscosity are greater, reaching differences of 800 cp, which emphasizes the importance of considering the effect of the mixed system when estimating viscosity.

It is important to notice that variation of the potential exponent of the T2log vs. viscosity equation is found to be between 10% and 20% greater than the one observed in free fluids, which is very similar to the range of irreducible water saturation found in the samples (Swi = 6% to 20%). This fact might suggest that the potential exponent of the mixed system is proportional to the water saturation which could be of high interest for future studies.

Correlations for the mixed system were also generalized for the echo time, obtaining similar results. General equations for the mixed system are shown below (15 to 20).

$$API = (-0.002 \cdot TE + 5.236) \cdot T2\log^{(5\cdot 10^{-5} \cdot TE + 0.152)} \quad (15)$$

$$API = (0.0013 \cdot TE + 3.375) \cdot \ln(T2\log) + (-0.014 \cdot TE - 8.110) \quad (16)$$

$$API = (-0.0025 \cdot TE + 6.698) \cdot Q1^{(5\cdot 10^{-5} \cdot TE + 0.139)} \quad (17)$$

$$API = (0.0012 \cdot TE + 3.087) \cdot \ln(Q1) - (-0.0125 \cdot TE - 2.817) \quad (18)$$

$$\mu = (131857 \cdot TE - 5 \cdot 10^{7}) \cdot T2\log^{(-0.0004 \cdot TE - 0.965)} \quad (19)$$

$$\mu = (17871 \cdot TE - 7.10^{6}) \cdot Q1^{(-0.0004 \cdot TE - 0.884)} \quad (20)$$

Sensibility analysis for these equations showed that the mixed system is more sensitive to variations in echo time. Figure 15 shows sensibility for API vs. T2log equation (equation 15), in which variations are greater than the ones observed for free fluids (figure 6). Viscosity changes are greater and very critical, since for some echo times it also reaches negative values which does not have a physical meaning (figure 16). However, if we observe the behavior of the equation constants vs. echo time (figure 17) it is obvious that, even tough a linear adjustment is fairly good (R^2 = 0.92), the constants have a remarkable exponential behavior, while for free fluids it was obviously linear. For this reason, viscosity equations were rewrited (equations 21 and 22) and another sensibility analysis was done. This time sensibility analysis showed that these correlations are more robust and allow variations in echo time with less error than in the linear case (figures 18).

$$\mu = (837886 \cdot \exp^{0.004 * TE}) \cdot T2\log^{(-0.0004 \cdot TE - 0.965)} \quad (21)$$

$$\mu = (187993 \cdot \exp^{0.004 * TE}) \cdot Q1^{(-0.0004 \cdot TE - 0.884)} \quad (22)$$

Conclusions

- Magnetic properties of fluids are function of its physical properties (viscosity and API gravity), what makes possible to estimate them through NMR measurements.
- The use of an specific correlation for estimating API gravity in a porous media may not be necessary, since correlations obtained in Berea rocks do not differ highly with the ones for free fluids.
- It is necessary the use of specific correlations to estimate oil viscosity in mixed systems, since significant differences vs. correlations for free fluids were observed.
- Correlation constants to estimate API gravity and viscosity are function of the echo time.

Recommendations

- It is recommended the use of the equations showed in this paper for estimation of oil viscosity and API gravity at irreducible water conditions in porous media of similar magnetic behavior than Berea rocks.
- This study should be extended to porous media with different magnetic behavior, to generalize the observations and extend the applicability of the correlations.

Nomenclature

a = correlation constant
b = correlation constant
T1 = longitudinal relaxation time
T2= transverse relaxation time
T2log = logarithmic average of T2 distribution
TE = interecho time
Q1 = first quartile of the T2 distribution

References

1. Kleinberg, R and H. Vinegar, "NMR properties of reservoir fluids", the log analyst, pp. 20-32, November – December 1996.
2. Morris, C., Freedman, R., Straley C., Johnston, M., Vinegar, H. and P. Tutunjian. "Hydrocarbon saturation and viscosity estimation from NMR logging in the Belridge Diatomite", SPWLA 35th Annual Logging Symposium, June 19-22, 1994.
3. Prammer, M., "NMR pore size distribution and permeability at the well site", SPE 69th Annual Technical Conference and Exhibition, SPE 28368, September 25-28, 1994.

Table 1 – Constants of free fluids correlations.

	TE (μs)	Con	T2log	Ln(T2log)	Q1	Ln(Q1)	T1
API	300	a	4.250	4.846	5.321	4.560	11.575
		b	0.178	-22.744	0.167	-16.869	0.208
	600	a	3.977	4.994	4.844	4.793	*
		b	0.183	-24.612	0.175	-19.497	*
	1200	a	3.488	5.303	4.210	5.160	*
		b	0.194	-28.392	0.187	-23.723	*
μ	300	a	2.10^6	**	$4.8.10^5$	**	6,207
		b	-1.042	**	-0.966	**	-1.243
	600	a	3.10^6	**	$8.2.10^5$	**	*
		b	-1.047	**	-1.013	**	*
	1200	a	6.10^6	**	$1.6.10^6$	**	*
		b	-1.127	**	-1.069	**	*

Table 2 – Constants of oil – water – Berea mixed system correlations.

	TE (μs)	Con	T2log	Ln(T2log)	Q1	Ln(Q1)	T1
API	300	a	4.659	3.757	5.943	3.480	11.461
		b	0.168	-12.282	0.156	-6.820	0.200
	600	a	3.886	4.134	5.189	3.779	*
		b	0.184	-16.490	0.169	-9.967	*
	1200	a	2.733	4.898	3.678	4.566	*
		b	0.216	-24.834	0.203	-17.973	*
μ	300	a	3.10^6	**	6.10^5	**	9667.4
		b	-1.080	**	-1.000	**	-1.304
	600	a	1.10^7	**	2.10^6	**	*
		b	-1.186	**	-1.087	**	*
	1200	a	1.10^8	**	2.10^7	**	*
		b	-1.415	**	-1.318	**	*

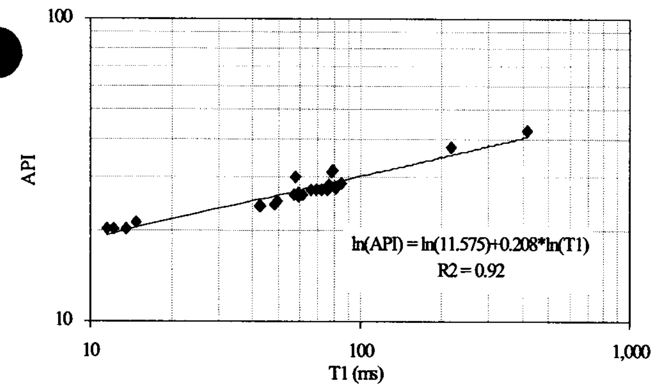

Fig. 1 – API gravity vs. T1 for Free fluids.

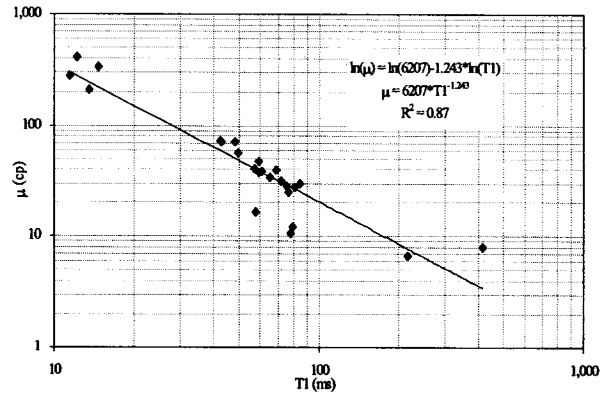

Fig. 2 – Viscosity vs. T1 for Free fluids.

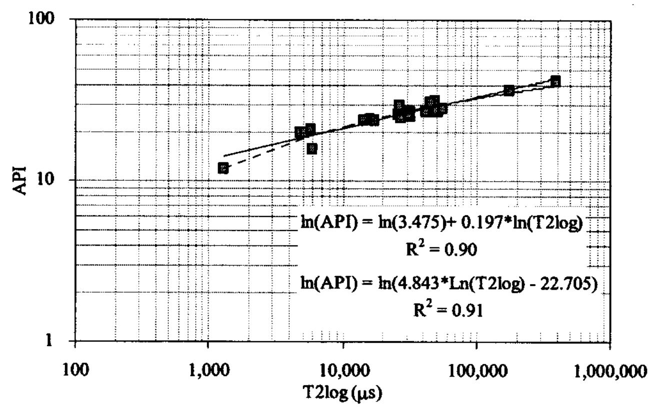

Fig. 3 – API gravity vs T2log (TE = 300 μs) for Free fluids.

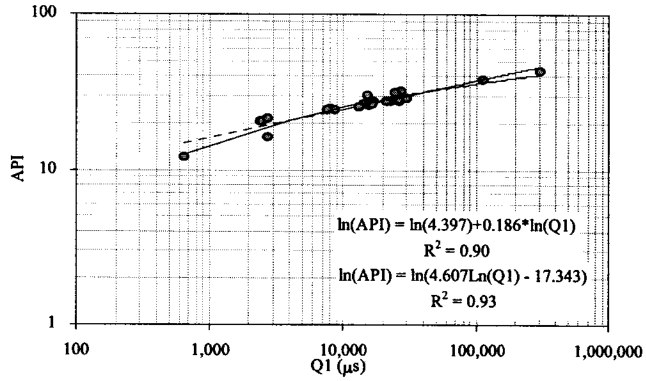

Fig. 4 – API gravity vs. Q1 (TE = 300 μs) for Free fluids.

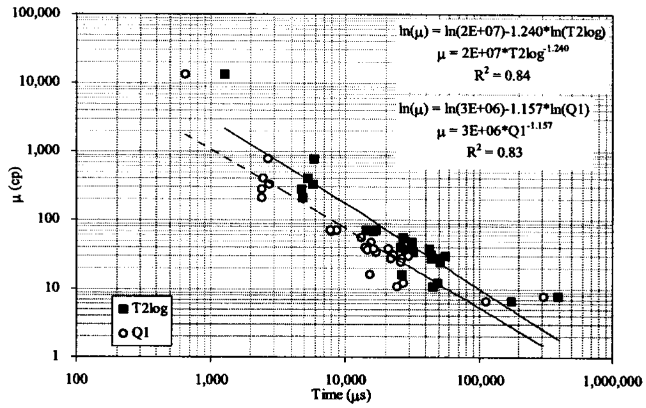

Fig. 5 – Viscosity vs. T2log and Q1 (TE = 300 μs) for Free fluids.

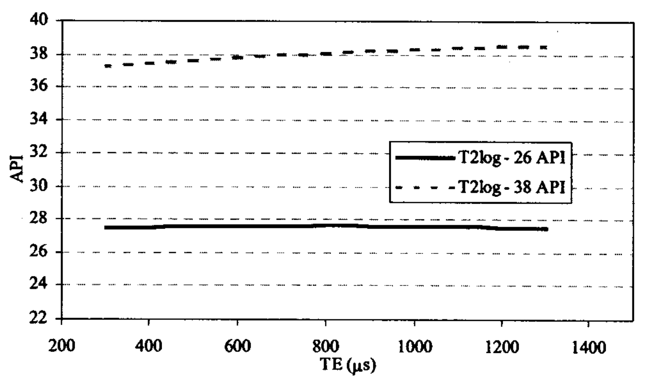

Fig. 6 – Sensitivity of equation 9 (API vs. T2log) to TE for Free fluids.

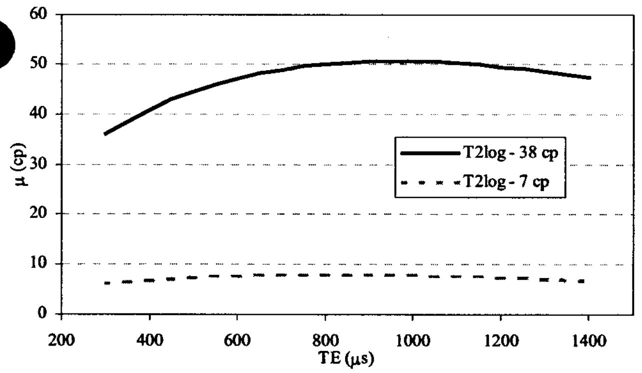

Fig. 7 – Sensitivity of equation 13 (Viscosity vs. T2log) to TE for Free fluids.

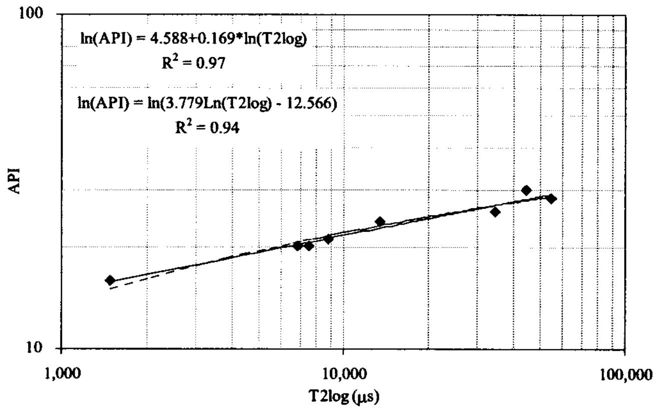

Fig. 10 – API gravity vs. T2log (TE = 300 μs) for the oil – water – Berea mixed system.

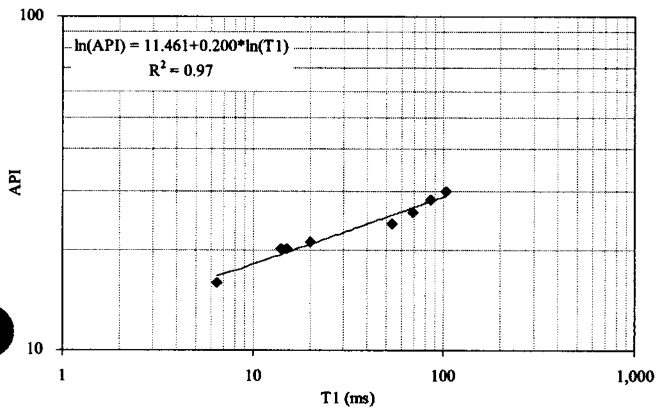

Fig. 8 – API gravity vs. T1 for the oil – water – Berea mixed system.

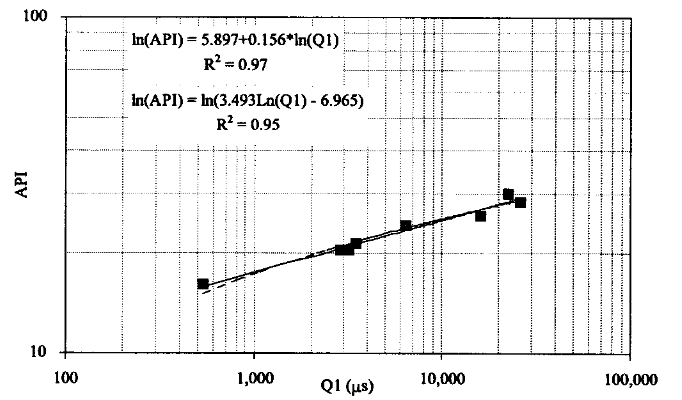

Fig. 11 – API gravity vs. Q1 (TE = 300 μs) for the oil – water – Berea mixed system.

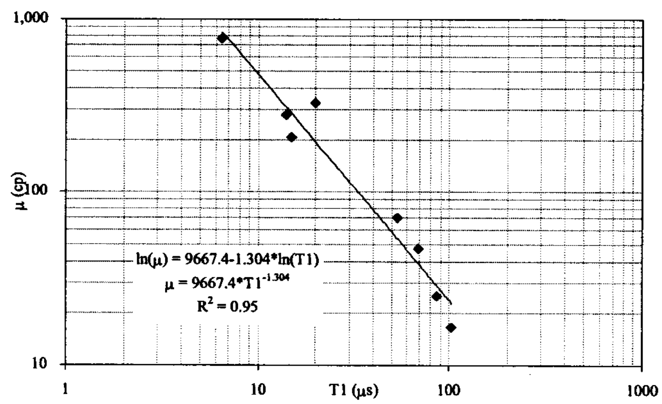

Fig. 9 – Viscosity vs. T1 for the oil – water – Berea mixed system.

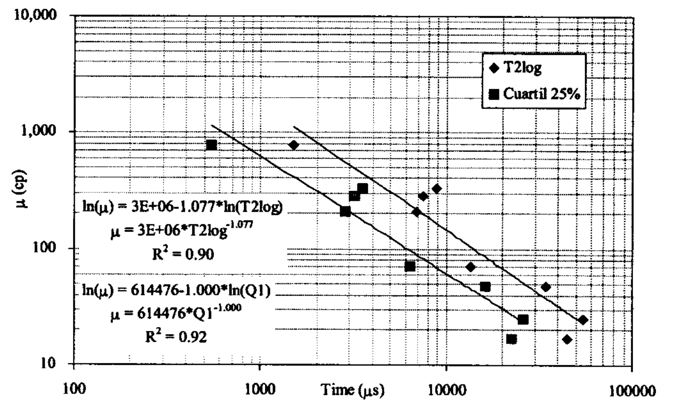

Fig. 12 – Viscosity vs. T2log and Q1 (TE = 300 μs) for the oil – water – Berea mixed system.

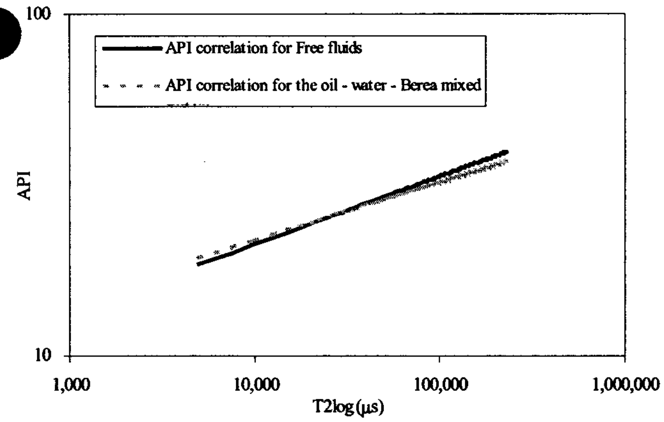

Fig. 13 – Comparison between API vs. T2log correlations (TE = 300 μs).

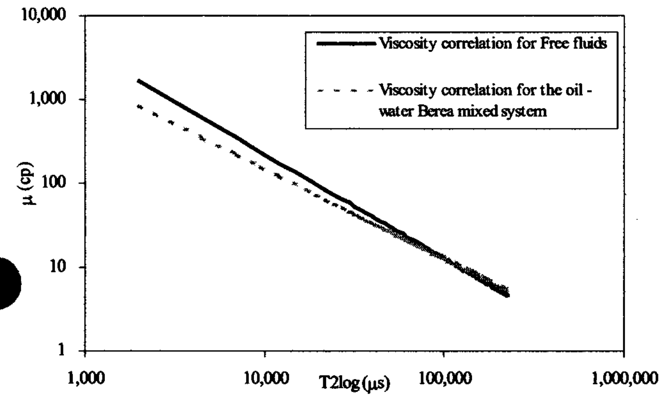

Fig. 14 – Comparison between Viscosity vs. T2log correlations (TE = 300 μs).

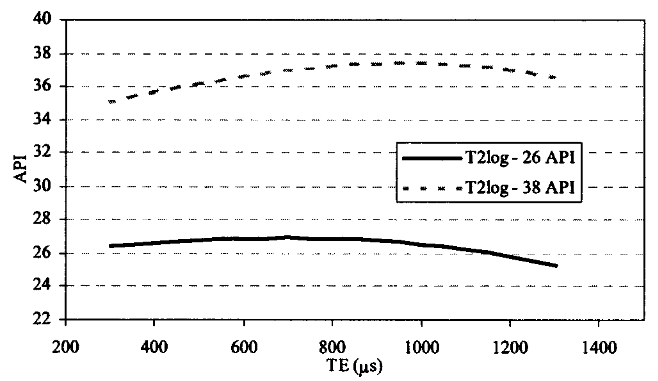

Fig. 15 – Sensitivity of equation 15 (API vs. T2log) to TE for the oil – water – Berea mixed system.

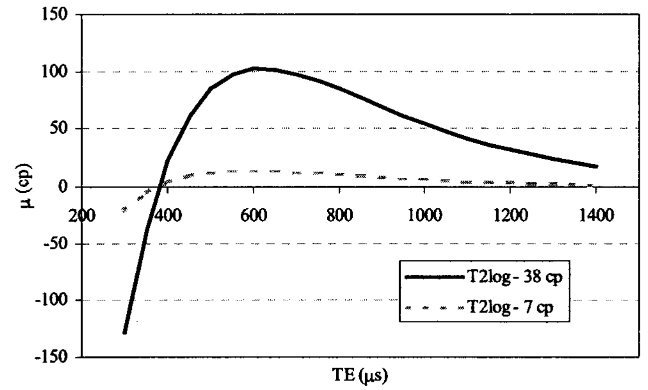

Fig. 16 – Sensitivity of equation 19 (Viscosity vs. T2log) to TE for the oil – water – Berea mixed system.

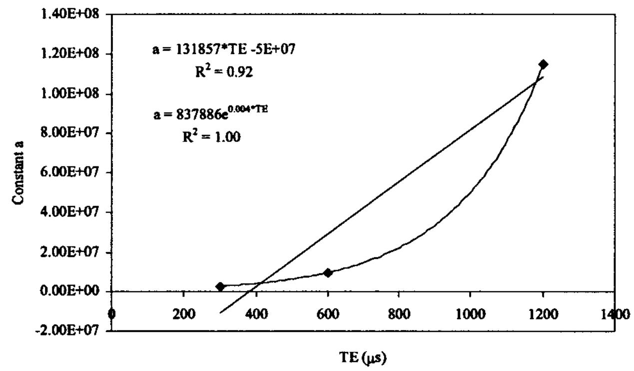

Fig. 17 – Constant a vs. TE (linear and exponential) for Viscosity vs. T2log correlations (equation 19) for the oil – water – Berea mixed system.

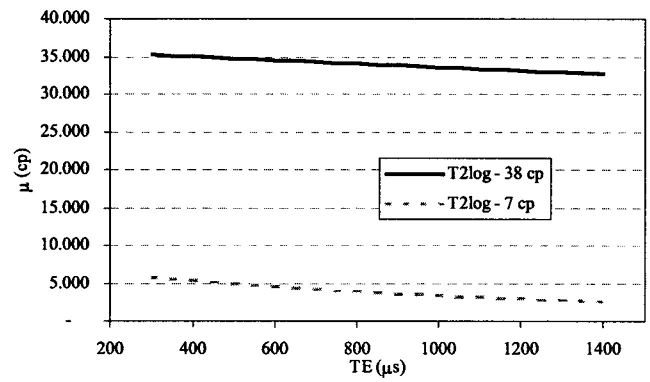

Fig. 18 – Sensitivity of equation 21 (Viscosity vs. T2log) to TE for the oil – water – Berea mixed system.