LABORATORY MRI INVESTIGATION IN THE EFFECTS OF INVERT OIL MUDS ON PRIMARY MRI LOG DETERMINATIONS

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ABSTRACT

Emulsifiers are common to invert oil mud systems since they are an aid to drilling mud stability. When filtrates from such muds invade, they may include some of these emulsifiers and result in an alteration of the rock's wetting characteristics.

This change in wetting alters the NMR response since the relaxation rate of an oil's hydrogen protons, when in contact with the rock, is typically much slower than the hydrogen protons of capillary bound water. Therefore, as the wetting fluid changes from water to oil, the relaxation rate, being measured by a MRI logging tools, changes. The consequence of this to the NMR interpreters, when they assume that no change has occurred in wettability, is an under-estimation of irreducible (*BVI*) water volume, and using a calculation of permeability dependent upon BVI, an over-call in permeability.

When the under called BVI scenario was identified from the comparison of core-to-log permeabilities in a series of wells drilled with inverted emulsion muds, it was speculated that the rocks wetness had been altered. To investigate, core samples were obtained from one of the suspect wells for a laboratory evaluation of the reservoir's NMR properties. A detailed laboratory protocol was then developed that focused on the investigation of the influence of inverted emulsion filtrates on such rocks, and to see if, and how the mud system alters the NMR characteristics.

A clear indication of wetting alteration was found, and the observed effect on *BVI* and permeability was confirmed, closely replicating the MRI BVI observations as given by the MRI log. Presented here are the procedures, methods and findings, as well as a new process for determining reliable *BVI* and permeability values when MRI logs are run in invert oil mud systems.

INTRODUCTION

Several MRI logs performed in the North Sea area were called into question when core measurements became available and showed the formations to be generally of poorer quality than predicted by MRI log results. Figure 1 is an example log from the area. It shows that MR permeability (*MPERM*) is generally higher than the core's, meaning the MRI log *BVI* (*MBVI*) to be too low.

A comparison of core BVI to MBVI was made as a point of reference. *CoreBVI* values were computed using the correlation shown in figure 2. This was accomplished using the samples from the troubled area. They were measured for air permeability (K_a) and desaturated to irreducible water saturation (S_{wi}) using an air/brine displacement (100 psi). *CoreBVI* values were then calculated from,

$$coreBVI = \left(0.334 K_a^{-0.115}\right) MPHI \quad \text{..........} \quad (1)$$

Comparing *MBVI* to the computed *CoreBVI* tends to verify that *BVI* is underestimated and the likely cause of the overestimation of *MPERM*. A closer inspection (fig. 1) shows *MPERM* to correctly reflect the relative amplitudes, but the magnitude is too high. The under-called BVI was linked to wells in the area that had been drilled with invert oil mud systems. Other wells drilled with water base muds, did not yield the same observations.

POTENTIAL REASONS FOR ANOMALOUS RESULTS

There are three potential reasons for this set of anomalous responses. First, the relaxation time used to separate bound from free fluid may be incorrect for these formations. Second, the permeability model may not represent the formation. Third, the oil filtrate may be carrying excess emulsifiers that are in a strong enough concentration to alter the wetting characteristics of the rock in the near well bore region. These options can be individually examined using MR laboratory measurements on core samples gathered from the area to assess the validity and necessary adjustments to the interpretive model.

Interpretive Model. The MR log response of amplitude versus time is determined using a multi-exponential function[1]. The cutoff time used to separate the capillary bound water from the fluid that is free to move[2,3] is then determined using a comparison of T_2 distributions from fully saturated to partially saturated where the partial is established at a specific capillary pressure.

It has been shown that cutoff values, even for sandstones, can vary quite widely[4,5] and to obtain the correct T_2 cut-off for a reservoir may require laboratory study if the best assessment of *BVI* and MR permeability is to be realized.

The commonly used Free Fluid permeability equation ,

$$MPERM = \left(\left({MPHI}/{10} \right)^2 \left({FFI}/{BVI} \right) \right)^2 \quad \text{....................} \quad (2)$$

would yield too high a value when BVI is underestimated, inferring a better rock quality than is actually present. In addition, the permeability model itself requires some verification through core measurements. Rewriting equation 2 in linear form yields the following:

$$\sqrt{{FFI}/{BVI}} = m\left({\sqrt[4]{K}}/{MPHI} \right) + b \quad \text{....................} \quad (3)$$

It readily becomes apparent that the intercept *b* is zero and the slope of the line *m*, assumed to be 10 is actually a variable.

Role of an Invert Oil Mud. Oil muds and invert oil muds both maintain a continuous phase of oil that provide the basic rheologic and fluid loss properties of the mud system[6]. The oil can be one of several types, from commonly used refined oils, like diesel, to synthetic oils, and for specific objectives, crude oil. Invert oil muds differ from oil muds, in that they maintain a water content in the form of very small droplets of water (sub-micron to micron size) in concentrations that can vary from 10 to 50%. Unlike oil muds, invert muds rely on the emulsified water to help maintain and control the rheologic and fluid loss properties of the mud system. Various emulsifying agents are added to the oil phase providing a tight film of surfactants at the interface between the brine and oil phases, keeping the water droplets small and in a discontinuous phase. These same emulsifiers act as effective oil wetting agents to drilled solids which become more easily lifted and carried to the surface with the oil phase for separation from the mud system.

It is known that surface active polar compounds, like the emulsifiers found in invert oil muds, adsorb on to rock surfaces after passing through a thin layer of water[7]. This process changes the wetting preference of the rock and in turn would change the MR characteristics. Additional primary factors controlling a wetting change are the mineralogy of the pore surface, brine chemistry, and pH of the brine, as well as temperature and pressure. These factors were held constant in the laboratory investigations presented.

MR Model to Recognize a Change in Wetting Preference. The interpretive models used to evaluate MRI logs in terms of *BVI* and MR permeability are based on the premise that the formation has a strong preference for water wetness. If emulsifiers are carried with the oil filtrate, it is possible for them to alter the wetting preference in the same manner that they function to make drilled fines oil wet for easier separation from the mud system. If a wetting change occurs (from water wet toward oil wet), Howard[8] showed that capillary bound water normally exhibiting fast relaxation times, shifts to longer relaxation times and light oil in long time, moves to shorter time (fig. 3).

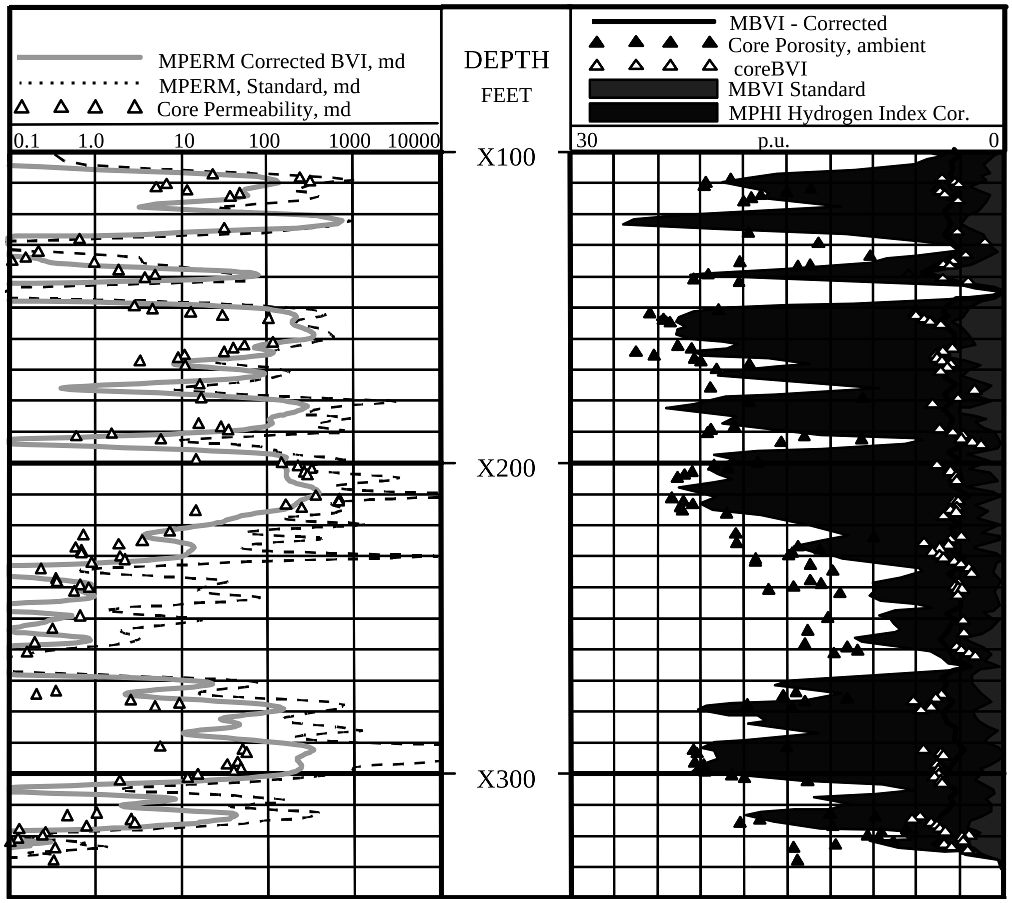

Figure 1: Example log from the study area. Note that the *coreBVI* is high to *MBVI* and *MPERM* is high compared to core perm. A new *MBVI* was computed (solid line in the porosity track) using the relationships presented in fig. 9. It matches well to the *coreBVI* and the new permeability computed (solid line in permeability track) is a good match to the core permeability.

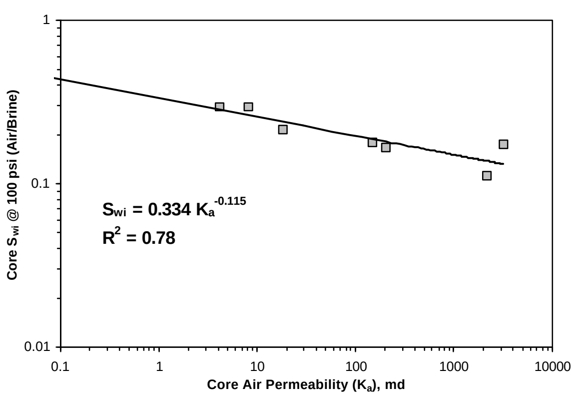

Figure 2: Correlation of measured S_{wi} values and permeability. MRI log values of *BVI* were compared to core S_{wi} values as predicted using this correlation.

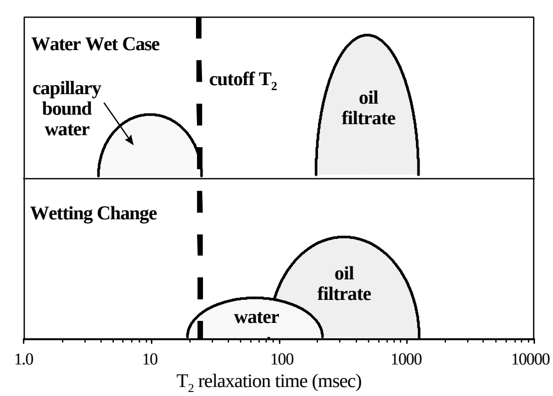

Figure 3: Magnetic resonance model representing a change in wetting from water wet toward oil wet for an oil mud filtrate.

This model would predict that a change in wetting would shift the *BVI* water to a longer relaxation time causing *MBVI* to be underestimated using a standard cutoff T_2. In turn, this would cause the MR permeability to be overestimated. However, this model does not imply that *MPERM* would match the character of the core permeability.

This can be explained if we consider Salathiel's[9] mixed wettability model. He proposes that alteration from water wet surfaces occurs more readily in larger pores, where a thinner layer of water does less to prevent deposition of wetting agents. Smaller pores with stronger capillary forces, exhibit thicker water layers and have the ability to maintain their water wet condition. This could explain observations on the subject log (fig. 1) that *MBVI* is a better match to *coreBVI* in lower permeability zones. Thus the character of the computed MPERM versus depth could emulate the character of core permeability versus depth as observed in the example well.

MR LABORATORY MEASUREMENTS

MR laboratory measurements were conducted in two phases. The first phase was to verify the interpretation model using selected core samples from the subject area. The second was to evaluate the effects of invert oil muds on primary MRI log determinations.

Validating the Interpretation Model. Six previously cleaned and dried 1.0 inch diameter plug samples (approximately 1 inch long) were selected for analysis. The samples were cleaned in a side-arm soxhlet using cycles of toluene/methanol in a 50/50 mixture and methanol to remove any residual oil and/or salts, making the core samples water wet[10]. The samples were dried in a vacuum oven (180° F) and analyzed to determine grain volume, grain density, ambient porosity and steady state air permeability.

The samples were vacuum pressure saturated using a synthesized formation brine and analyzed for MR properties using a spectrometer of equivalent frequency (~1 MHz) to the downhole MRI logging tool. Four of the six samples were desaturated using air/brine displacement first to 50 psi, and then to 100 psi, followed by MR spectrometer measurements after each desaturation cycle.

Analysis of Model Validation Results. Laboratory MR testing on brine saturated samples confirms that the interpretive models used do not simulate the observed underestimation of BVI or overestimation of permeability. Table 1 summarizes the results, in which MR S_{wi} values are compared to the core measured values. MR S_{wi} is determined by summing the incremental MR porosity for each T_2 bin to a fixed cutoff T_2 which determines *MBVI*. MR S_{wi} is the ratio of *MBVI* to *MPHI*. Cutoff T_2 values used were 22.6 and 33 (msec.) which are common standards for sandstone interpretation. The results show that in general both cutoff values overestimate *BVI*, opposing the anomalous results. MR Permeability was computed using equation 2, with MBVI taken at 22.6 (msec.). As shown in table 1, the permeability is a reasonable match; however, MPERM underestimates permeability in the better reservoir quality and further overestimates permeability in poorer reservoir quality which is not congruent with log observations.

Effects of Invert Oil Muds. The effects of invert oil muds were investigated for different reservoir initial saturation conditions and different wetting conditions. The first set of tests was conducted to evaluate the effect of an invert oil mud as if the oil filtrate was invading a water zone. The second was to investigate the effects of same oil filtrate invading a water wet oil productive zone. Oil filtrate for these tests was acquired by pressing several gallons of whole mud from the subject well. Further testing was conducted using a simulated oil filtrate. The simulated filtrate was a mixture of the base oil and different concentrations of emulsifiers that would bracket known concentrations of emulsifiers used in preparing invert oil muds (2 to 20 pounds per barrel (ppb)). The four samples previously analyzed at three different saturation conditions were selected for this further analysis. Three additional samples, restored[11] to their wetting preference, were analyzed before and after flushing with simulated oil filtrate.

Effects in Water Zones. The partially saturated samples were cleaned as before, using cycles of methanol only, then dried and resaturated with the same brine. The samples were placed in a hydrostatic core holder and flushed dynamically using the pressed mud filtrate (*PMF*). Downstream water was captured and volumetrically measured until stable. This required approximately 10-15 pore volumes of *PMF*.

Figure 4 is a comparison of the T_2 distributions of the four samples in three saturation states, S_w = 100%, after air/brine drainage (100 psi) and after flushing with PMF. As the model in figure 3 dictates, a change in wetting is indicated if the short time T_2 components (in the range of .1 to 33 ms) are reduced or eliminated and the long time T_2 components of the oil filtrate shift downward from it's bulk liquid T_2. Figure 4 shows that in all the samples there is no significant change in the short time components. Furthermore, BVI determined after air/brine drainage is a good match to MBVI, at a cutoff T_2 of 22.6 (msec.), and continues to match well for cutoff T_2 values ranging from 22.6 to 80 (msec.).

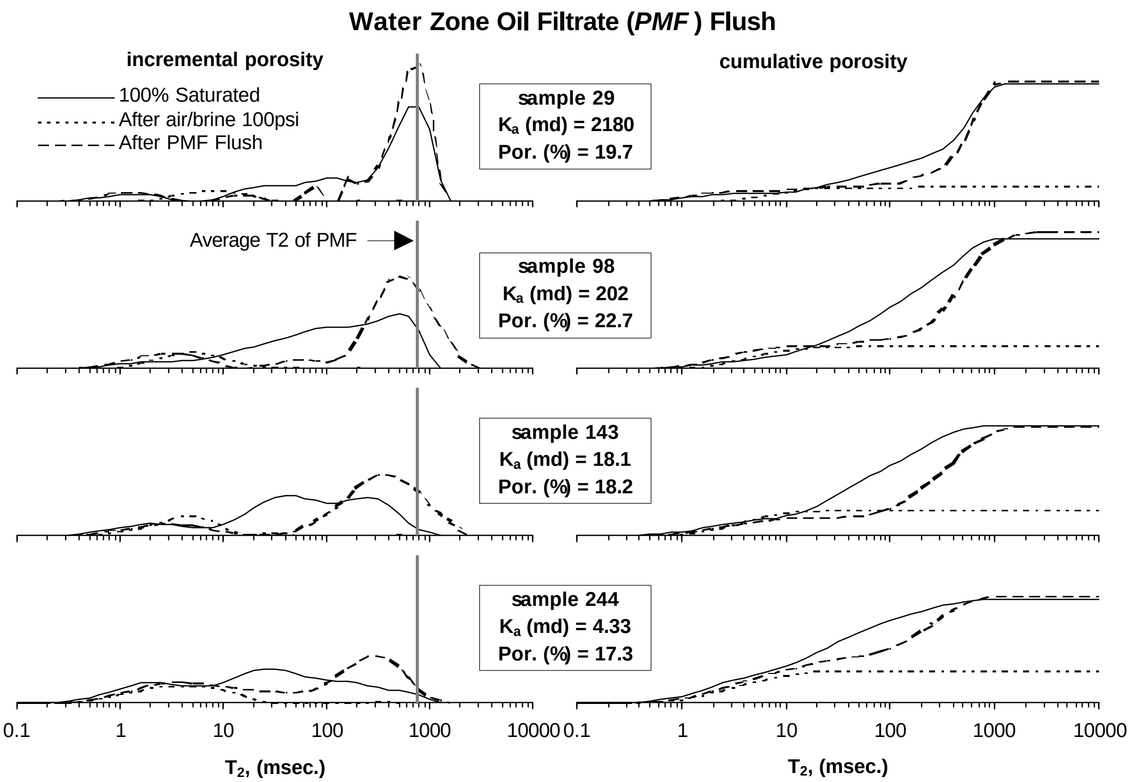

Figure 4: Pressed mud filtrate (*PMF*) was used to dynamically displace brine saturated cores of various rock quality. There was no apparent change in *BVI*.

An MR measurement of the bulk liquid *PMF* sample was made and the geometric average T_2 was determined to be 755 (msec.) at laboratory temperature and is displayed as a vertical line in figure 4. As expected there is a build up of amplitude in longer time associated with *PMF* flushing, and it is clear that the later time *PMF* peak shifts away from the bulk *PMF* T_2 for three of the four samples. However, in order for a change in wetting to be confirmed, this observation should occur simultaneously with a reduction in *BVI* components. The peak associated with the *PMF* shifts further away from the bulk *PMF* T_2 value as the rock quality decreases (lower permeability and porosity), implying that the signal from the *PMF* exhibits a dependence on pore size and/or internal gradients. This observation is inconsistent with previous experiments that indicate that non wetting oils will maintain and mimic their bulk T_2 independent of pore size.

Effects in Oil Zones. After flushing with *PMF* to investigate water zones, the samples were cleaned using toluene/methanol and methanol cycles as before to assure the samples would return to a water wet condition. The samples were dried and saturated with the same brine as previously described. Produced conditioned* crude oil was used as the oil phase in a centrifuge oil/brine displacement at an equivalent

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* Conditioned refers to crude oil that has had water and particulate materials removed.

air/brine pressure of 100 psi as used in previous air/brine displacements. Standard precautions were used that reduce or eliminate end effects. After oil/brine displacement, the samples were analyzed for MR characteristics and then flushed dynamically with *PMF*.

T_2 distributions of the four samples are displayed in figure 5 in four saturation states: S_w = 100%, after air/brine drainage (100 psi), after centrifuging crude oil displacing brine, and after flushing with *PMF*. In all cases no sign of wetting change is apparent. As shown in the previous tests, investigating water bearing zones using a cutoff T_2 of 22.6 (msec.) to determine *MBVI* compares well to the known core *BVI* condition. A shift downward in the *PMF* peak is apparent when compared to its bulk T_2, however; as before, this apparent change in wetting is not supported by a change in the short time portion of the spectrum. It is more likely that this shift is due to components (with shorter relaxation times) from the crude oil that are miscible with the *PMF*.

Using a Simulated Filtrate. In the experiments performed so far, there remains no explanation for the low *BVI* values observed on the logs in question. It was hypothesized that the pressed mud filtrate being used did not contain the amount of emulsifiers needed to alter the wetting preference. Assuming the process used to acquire the pressed mud filtrate was faulty, a synthetic mud filtrate was formulated by mixing the base oil used to formulate the invert mud and adding prescribed concentrations of emulsifiers. The first simulated mud filtrate (*SMF*) was formulated to contain 10 (ppb) of emulsifiers which in this area was a common amount used to keep water in a discontinuous phase.

The same samples previously flushed with *PMF* had been preserved and were dynamically flushed with the *SMF* (containing 10 ppb of emulsifiers). T_2 distributions of the four samples are displayed in figure 6. Three saturation states are shown for comparison: after air/brine drainage (100 psi), after centrifuging crude oil displacing brine, and after flushing with the *SMF* plus emulsifiers. Three of the four samples show a significant alteration in the BVI portion of the spectrum. Displayed most predominantly in the cumulative curves, it is clear that *MBVI* at a standard cutoff T_2 of 22.6 (msec.) will significantly underestimate the known core *BVI*. A shift downward in the *SMF* peak is apparent when compared to it's bulk T_2 (780 msec., the vertical line), which is further confirmation that a change in wetting has occurred.

Another important observation from study of the distributions is that the poorest quality rock sample (sample 244) showed no susceptibility to the added emulsifiers. Further confirmation of this comes from the fact that a second *SMF* flush was performed with a formulation of 20 ppb emulsifiers, with no change in *MBVI* for this sample. This tends to support the supposition that smaller pores with greater capillary forces and thicker water layers are able to prevent a wetting change from occuring[9,10].

Effects of Emulsifier Concentration. The four samples tested previously were cleaned as before using cycles of toluene/methanol and methanol until no discoloration or salts were detected in the effluents. It was noted however, that the time required and number of cycles dramatically increased from previous cleaning cycles which is consistent with a change in wetting, from water wet toward oil wetness. The samples were prepared as before using the same brine and crude oil for displacement in the centrifuge. The samples were then dynamically flushed with two simulated mud filtrates, one with 2 ppb of emulsifiers added (the lower limit commonly added), and the other with 4 ppb of emulsifiers added.

T_2 distributions of the four samples are displayed in figure 7. Four different distributions are shown for comparison, representing a) after air/brine drainage (100 psi), b) after centrifuging crude oil displacing brine, c) after flushing with the *SMF* with 2ppb of emulsifiers and d) after flushing with SMF with 4ppb of emulsifiers. Again, three of the four samples show a significant alteration in the BVI portion of the spectrum which is demonstrated by the drop in cumulative porosity compared to the oil/brine and air/brine displacements. A shift downward in the *SMF* peak compared to it's bulk T_2 further supports that a change in wetting has occurred.

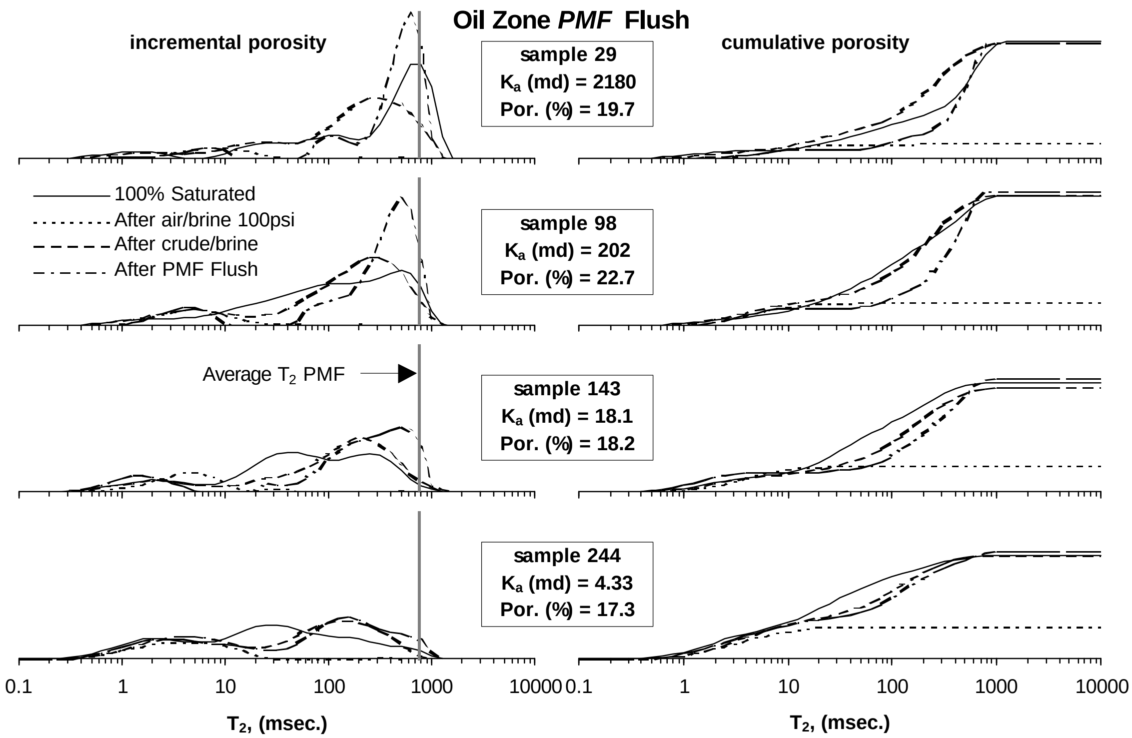

Figure 5: The same samples, starting brine saturated, were centrifuged with crude draining brine. *PMF* was used to dynamically flush the crude oil with no apparent change in *BVI*.

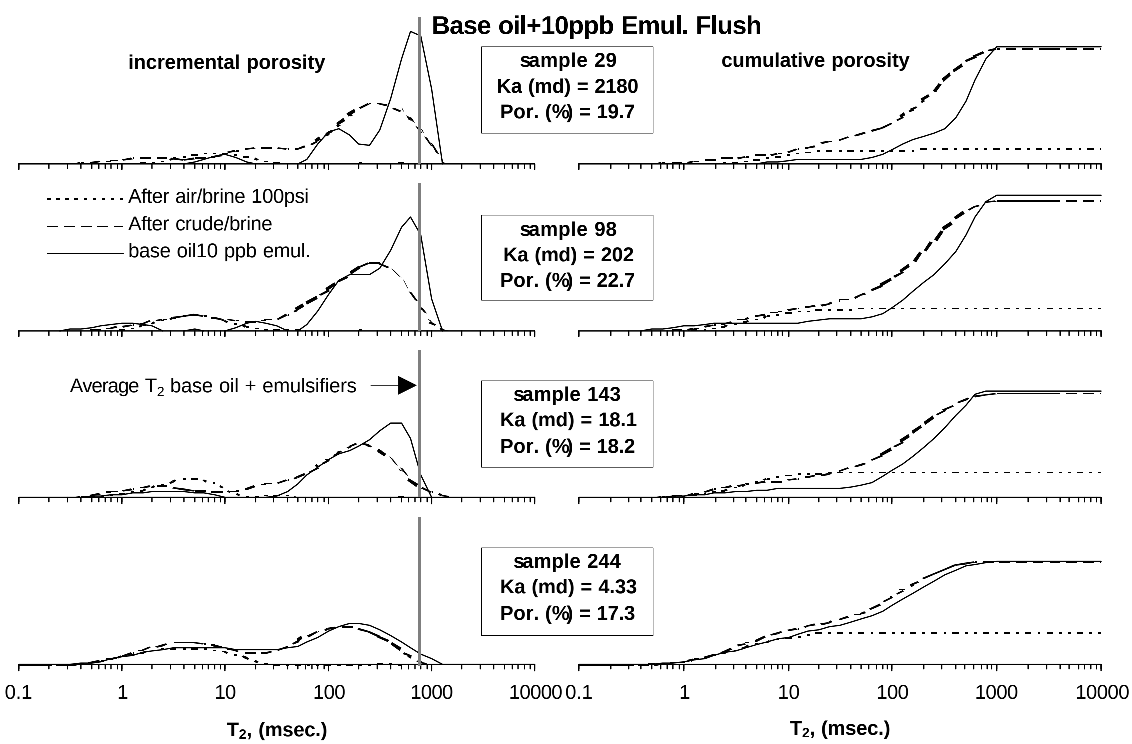

Figure 6: After flushing with *PMF* and getting no change in *BVI*, a simulated mud filtrate (*SMF*) was used that contained 10 ppb of emulsifiers added. It is evident in all but sample 244, the lowest permeability sample, that *BVI* has been reduced.

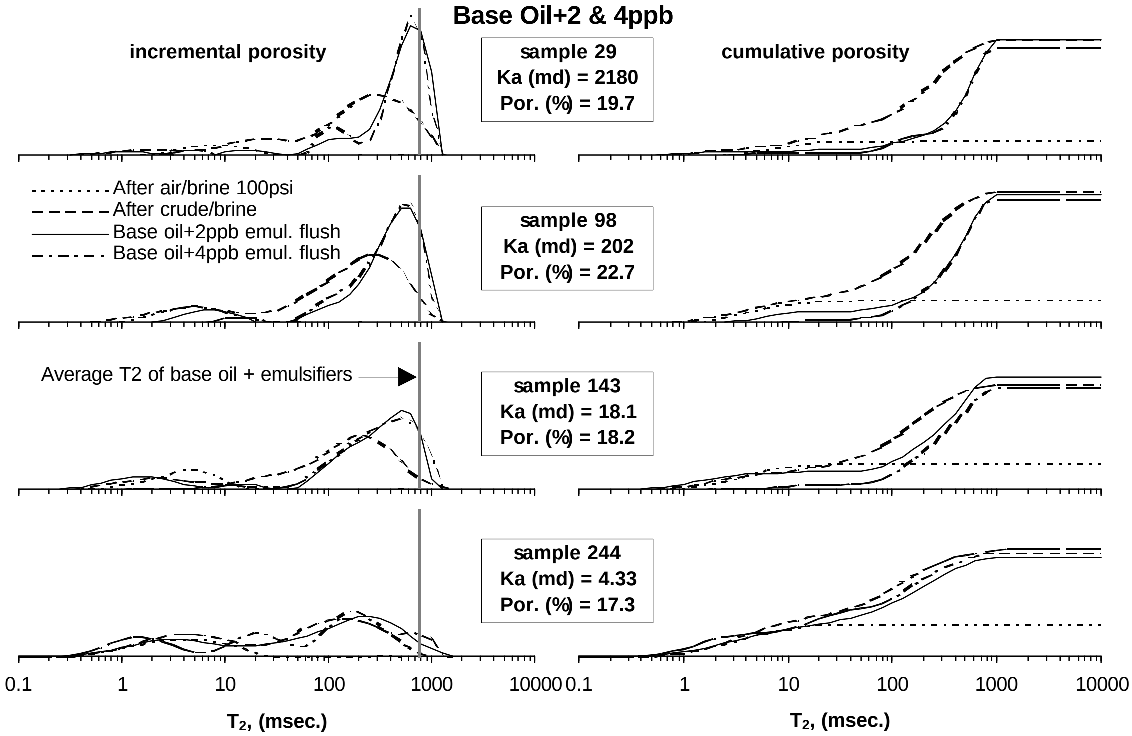

Figure 7: After cleaning, drying, brine saturating and crude/brine drainage, the samples were flushed with lower concentrations of emulsifiers, 2 ppb and 4 ppb. *BVI* was reduced in all cases except sample 244. The lowest concentration appears to have less effect on samples 98 and 143.

Two of the four samples (98 and 143) show that there is a greater reduction in *BVI* when the *SMF* with 2ppb of emulsifiers was followed by a flushing with *SMF* with 4ppb of emulsifiers. To a much lesser extent, the same observation is shown in the high permeability sample (29). This implies that two factors allow or inhibit a wetting change. First, there is some dependence on the concentration of emulsifiers that have been carried with the mud filtrate and second, the rock quality being invaded (i.e. how thick is the water layer). As before, the poorest quality rock sample (244) shows no change in wetting preference and/or primary MR parameters.

Cores Restored to "Reservoir Wetting Condition". Samples from the subject well were processed to restore the reservoir wetting conditions and preserved† prior to analysis. The samples were removed from their preservation material, placed in air tight containers and analyzed as received for MR characteristics. Simulated oil filtrates were formulated to have 2 (ppb), 4 (ppb) and 8 (ppb) emulsifiers. The first *SMF* with 2 (ppb) of emulsifiers was flushed dynamically into each core sample and analyzed for MR characteristics. This process was repeated for each emulsifier concentration. At the end of this analysis the samples were cleaned, dried, saturated with the same brine and desaturated (air/brine displacement at 100 psi) using the same techniques described previously.

The results for the three samples are summarized in Figure 8. The T_2 distributions for each sample shown compare four conditions: as received, after flushing with *SMF* with 2 (ppb) emulsifiers, after flushing with *SMF* with 8 (ppb) emulsifiers, and after air/brine drainage (100 psi). Comparing the T_2 distribution for the

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† Preserved in this case means the crude oil was displaced with refined laboratory mineral oil (Isopar L) wrapped in Saran™ wrap with an outer layer of aluminum foil and dipped in CoreSeal™.

after air/brine drainage to the as received T_2 distribution it becomes apparent that the samples had already been altered from a water wet state toward an oil wet state. Flushing with the simulated mud filtrates with emulsifiers in any of the three concentrations did not (in terms of BVI) significantly change the distributions in any of the samples.

This information would suggest that the symptoms observed on MRI logs may have been evidence that the reservoir rock in the subject well is actually shifted toward an oil wetness. This would suggest the original BVI values are not anomalous, but are representative of rock that is more oil wet. It must be recognized however, that the restored-state samples may not have been representative of the actual reservoir wetting condition. Alteration in wetting from the drilling fluids and core handling procedures is common and specific processes must be used to clean contaminated samples prior to restoring wetting[7,11].

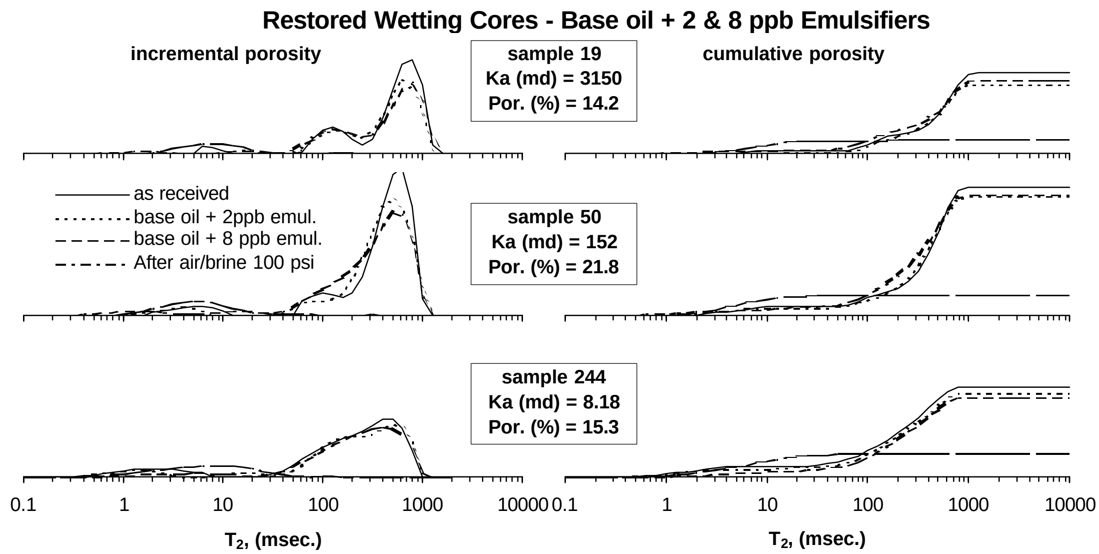

Figure 8: Cores samples previously restored to reservoir wetting conditions were analyzed as received for MR characteristics then flushed with a simulated mud filtrate with concentrations of 2 and 8 ppb. No change in *BVI* was observed for these samples implying the reservoirs wetting condition is toward an oil wetness.

AUXILIARY LABORATORY MEASUREMENTS IN SUPPORT OF CONCLUSIONS

No change in wetting was observed when the samples were flushed with *PMF*. If the *PMF* could be analyzed and shown to have lower concentrations of emulsifiers than the 2ppb mixture of the *SMF*, then a logical conclusion is that the *PMF* did not have a high enough concentration of emulsifiers to cause a change in wetting. Gas chromatography and spinning drop interfacial tension measurements were made on the *PMF* and *SMF* fluids to assess each one's emulsifier concentration.

After establishing a base line for the fluid in their pure product form, the *PMF* and *SMF* fluids were analyzed chromatographically. While the results were somewhat inconclusive they did indicate that the *PMF* filtrate contained low concentrations of emulsifiers compared to the 2ppb *SMF*. The IFT results confirmed, as shown in table 2, that the concentration of emulsifiers in the *PMF* was less than 2ppb as contained in the *SMF*.

ALTERNATIVE METHOD FOR MBVI

The potential of emulsifiers in invert muds to alter wetting makes it necessary to provide an alternative method of determining *MBVI*. The methodology that follows was an outcome of this study, and assumes, that a) water wetness is the natural reservoir wetting condition, and b) the invert mud has changed the wetting preference shifting the *BVI* signal from short T_2 times to longer T_2 times. A fixed cutoff value longer in relaxation time (90.5 msec.) was selected to determine *MBVI* apparent ($MBVI_a$) and compare it to the *CoreBVI* values. Figure 10 shows that there is a correlation between the difference ($\Delta BVI = MBVI_a$ - *CoreBVI*) and $MBVI_a$. The correlation shown in equation 4, can be used to correct $MBVI_a$ to a new *MBVI* based on core measurements of *BVI*.

$$\Delta BVI = -0.641 MBVI_a + 2.239 \quad (4)$$

Figure 9 displays all concentrations used, demonstrating that this alternate method is not dependent on the concentration of emulsifiers and can be applied without knowledge of such. This observation also corresponds to the fact that once the reaction occurred, stronger concentrations did little to evoke more of a change in the shorter time components. Further examination shows that this trend line is shifted up from another trend line that is developed using the same cutoff parameter but applying this methodology to the sample analyzed via lab MR measurements that were at the condition of S_w = 100% (equ. 5). Note that the slope of both lines is very similar indicating that even though a wetting change has occurred the shift is consistent and correctable.

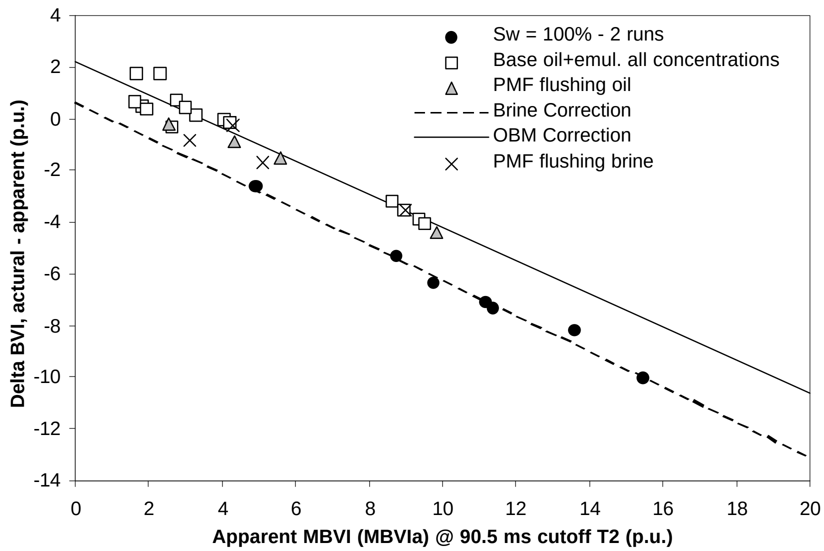

Figure 9: Based on the core MR experiments, using a fixed cutoff T_2 at 90.5 (msec.) the difference from a measured CoreBVI value is determined. Adding this value to the apparent MBVIa value corrects MBVI for the effects of invert oil muds..

$$\Delta BVI = -0.687 MBVI_a + 0.680 \quad (5)$$

The strong correlation for the samples at S_w = 100% implies that this method can be used as a standard approach to enhance *MBVI* determinations. It can be applied when a change in reservoir wetting is not suspected and when MR core data is available.

Application of the Correction Method. Figure 1 also shows new *MBVI* values that have been computed applying the correlation shown in equation 4 and figure 9. Note that the new *MBVI* now agrees well with *CoreBVI* and the new permeability computed using the new *MBVI* is now in good agreement.

CONCLUSIONS

It has been confirmed that emulsifier in invert oil muds can change the wetting preference (water wet toward oil wet) of rock surfaces, thus altering primary MR parameters subsequently determined. The alteration occurs most significantly in higher permeability and porosity rock types. This is likely due to the fact that a thick water layer in poorer reservoir rock inhibits the surface active agents from adsorbing onto rock surfaces and that less dynamic flushing occurs in lower permeability rock. The reaction that occurred appeared insensitive to the concentration of surfactant although at the lowest concentration used some signs of less reaction were apparent.

Pressed mud filtrate from the subject well was originally used to investigate these wetting changes, however no wetting change was apparent on samples flushed with this filtrate. Only when simulated mud filtrates were used (having concentrations of 2 to 20 ppb emulsifiers) was a significant and immediate change in wetting observed causing *MBVI* to underestimate *BVI*.

The correction process demonstrated in figure 9 is not sensitive to the concentration of the emulsifier. This correction process performs well under the assumption that a wetting change from water wet toward oil wet was caused by the invert oil mud in the sensitive volume investigated by the MRI log. This correction process can also be used to enhance *MBVI* determinations when laboratory core MR measurements are available.

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Table 1: Test of Interpretation Model

#	Core K_a md	S_{wi} 50psi %	S_{wi} 100psi %	MR S_{wi}* %	MR S_{wi}@ %	MR PERM md
29	2180	13.7	11.3	10.7	14.2	921
98	202	22.9	16.6	17.4	22.7	509
137	8.30			22.2	27.1	8.64
143	18.0	29.7	21.5	27.0	38.8	84.3
178	509			9.2	12.6	199
244	4.33	43.2	29.4	51.0	59.2	9.76

* MR S_{wi} @ 22.6 (msec.), @MR S_{wi} @ 33 (msec.)

Table 2: Interfacial Tension Measurements

Fluid Sample	IFT dynes/cm	Comments
Base oil	7.9	clear 2 phase
Base oil+2 ppb emul.	2.5	clear, colored top phase.
Base oil+10 ppb emul.	2.1	macro-emulsion at interface, IFT could be much lower.
PMF run 1	5.9	2 phase system with some particulates in the middle
PMF run 2	5.6	2 phase system with some particulates in the middle