

Specialized Surfactant Technology Applications Enable Project Successes

Patricia Ullauri, Carlos Toro, Cesar Guerra, Tom Jones and Lirio Quintero, Baker Hughes

Copyright 2012, AADE

This paper was prepared for presentation at the 2012 AADE Fluids Technical Conference and Exhibition held at the Hilton Houston North Hotel, Houston, Texas, April 10-11, 2012. This conference was sponsored by the American Association of Drilling Engineers. The information presented in this paper does not reflect any position, claim or endorsement made or implied by the American Association of Drilling Engineers, their officers or members. Questions concerning the content of this paper should be directed to the individual(s) listed as author(s) of this work.

Abstract

Surfactants systems have been used in oil well drilling and completion fluids for several decades and have been used for numerous applications, including emulsification of brine for invert emulsion fluids, emulsion prevention in completion fluids, wellbore clean-up in spacer trains, flowback enhancement in drill-in fluids and numerous other applications.

In recent years, the use of specialized designer surfactant blends to remove formation damage and dramatically improve production in cased hole and open hole completed wells has prompted field personnel to expand the range of target applications of this technology.

The aforementioned specialized surfactant blends have several unique functional characteristics that make them ideal for multiple uses in the field. Generally, these systems solubilize oil, remove oil from surfaces, remove emulsions, water-wet and disperse solids, reduce interfacial tension and mobilize in-situ fluids.

With a full understanding of the mechanistic ways that these surfactant blends function under downhole conditions and when confronted with various operational issues in the field, this technology was successfully used to free stuck pipe, to free blocked completion screens of heavy oil sediments and to prepare a well for water injection.

This paper presents the technology associated with specialized designer surfactant blends and the case studies where the technology was applied in the field to enable project successes.

Introduction

Prevention of formation damage has been a major emphasis for fluid designs targeted for the reservoir drill-in and completion phases of drilling projects.¹⁻² Similarly, surfactant systems for more effective displacements, drill-in fluid filter cake removal, and perforation damage remediation have been introduced to further enhance wellbore productivity and achieve project objectives.

As the frequency and success of designer surfactant systems applied to a wide range of wellbore clean-up scenarios increased, an expanded understanding of their versatility by R&D departments began to emerge. Transferring this new technology to field personnel can be a painstakingly long process; however, once the basic fundamentals are fully understood, the scope and number of field applications expand, leading to a similar expansion of the

technology to include markets not previously conceived by research personnel.

One of the new surfactant system designs that enjoyed significant success is the removal of S/OBM filter cakes in open hole (OH) completions with microemulsion technology.³ Likewise, in wellbore displacements and cased hole (CH) remediation applications, microemulsion technology has been successfully applied to clean oily debris from casing and to treat damaged perforation zones. As will be explained in more detail, these surfactant systems impart ultra-low interfacial tension (IFT) between in-situ fluids and the surfactant-based treatment fluids. The low IFT, in turn, is associated with high oil solubilization, increased diffusion rate, and enhanced fluid mobility and the dispersion of compacted oil-wet solids to achieve a wide range of downhole objectives.

When field personnel began to more fully understand the value of low IFT, high diffusion coefficients, oil solubility, water-wetting phenomenon and fluid mobility alteration, they began to envision a rash of new field applications for microemulsion technology. This paper presents the process used to select and combine surfactants to design highly efficient microemulsion cleaning fluids not only targeted to improve reservoir production but also to improve other critical processes during the wellbore construction process. In addition, three field applications are presented that demonstrate the successful application of these specially designed surfactant systems.

Selection of Surfactants for Treatment Fluids

The process of selecting a formulation with surfactants for enhancing well injection or production needs be done systematically. Normally, this includes phase behavior studies as a function of the composition, and studies of interfacial tension, contact angle, fluids compatibility and permeability evaluation⁴

These surface-active additive packages consist of a blend of surfactants and co-surfactants that are soluble in water. The selection of these additives is determined from systematic phase behavior studies in brine-oil-surfactant systems. Additional components, such as acid, are also included in the phase behavior studies. In general, the performance of the surface-active additive packages and phase behavior of the system is significantly influenced by temperature, salinity, oil/water ratio, and other factors.

The data obtained from the phase behavior studies was used to build the phase diagrams, allowing better understanding of capabilities and possible performance of the fluid formulated with a particular brine-surfactant-oil system.

Figure 1 shows a generic phase diagram built for the brine-surfactant-oil system evaluated with the particular objective of selecting the composition of treatment fluids from the neighborhood surrounding of the “optimum formulation” defined in fundamental studies of water-oil-surfactants systems (microemulsion systems).⁵ These fluids are characterized by having very low interfacial tension, changing the wettability from oil-wet to water-wet and inducing in-situ microemulsification of oil and organic materials.

These microemulsion systems are characterized for being a thermodynamically stable single phase fluids

These microemulsion systems are characterized as being thermodynamically stable single-phase fluids consisting of microdomains of oil and/or water stabilized by an interfacial film of surfactant molecules.⁶⁻⁸ These types of fluids have self-diffusion coefficients close to the values of the neat fluids used in the formulation, which produce a very high diffusion rate when used as cleaning fluids.⁹

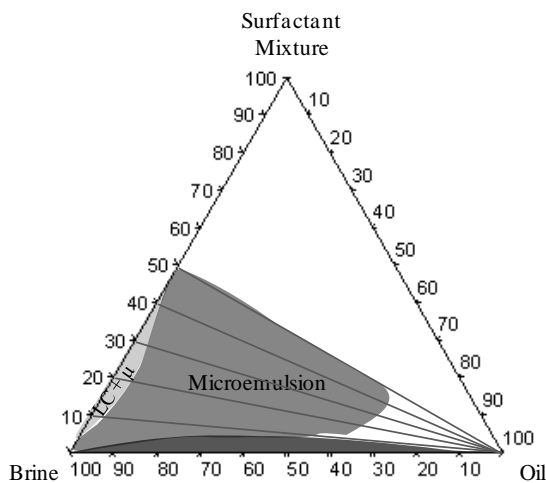


Fig. 1 Generic phase diagram of brine-surfactant-oil system used in treatment formulations

Laboratory Evaluation

Formulation

Various treatment fluids selected from the studies of brine-surfactant-oil systems were evaluated for the specific conditions required for the field applications discussed in this paper. The particular fluids selected include (1) microemulsion systems formulated with surfactants, co-surfactants, brine, a solvent and an acid; and (2) in-situ microemulsion systems formulated with surfactants, co-surfactants, and brine. The in-situ microemulsion was designed to form a microemulsion fluid as soon as it gets in contact with the oily material downhole.

In addition to the phase behavior studies, the selection of surfactants includes other key tests, such as interfacial tension measurement, fluids compatibility and cleaning properties.

Interfacial Tension Evaluation

For a treatment fluid involving surfactants to be an effective oil cleaning fluid, it needs to have ultra-low interfacial tension when it gets into contact with the crude oil or oily material to be cleaned. Therefore, interfacial tension (IFT) measurements were performed between the treatment fluids and the base oil used in OBM or between the treatment fluid and crude oil. Various crude oils, having low, medium and high API degree were used in these tests. Measurements of IFT were made using a SVT20 model Dataphysics Spinning Droplet Tensiometer. **Figure 2** shows the interfacial tension between crude oil samples and the microemulsion fluid. The results show that the interfacial tension is less than 0.8 mN/m at the initial contact of the fluids and then decreases rapidly with time. Similar results were obtained in the case of the IFT measurement of the in-situ microemulsion system evaluated with three based oils (**Figure 3**). The brine-surfactant system shows a very low interfacial tension as soon as it comes in contact with the base oils (diesel, paraffin and mineral oil).

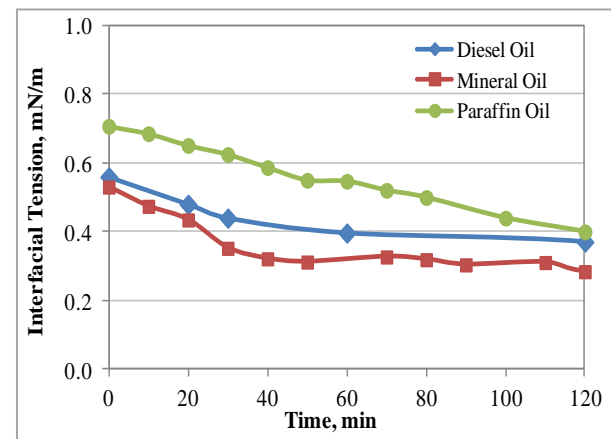


Fig. 2 Interfacial tension between based oil used in OBM and microemulsion fluid

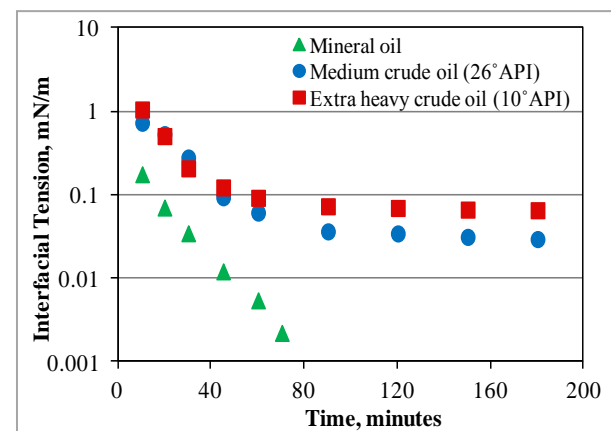


Fig. 3 Interfacial tension between crude oil and in-situ microemulsion fluid

Fluids compatibility and cleaning tests for injector well application

To qualify these treatments for cleaning the oil-bearing zone for the injector well, it was necessary to evaluate the compatibility of the injection water/crude oil/treatment fluid. **Table 1** presents some relevant information for the injection water that generally influences the surfactant systems. **Figure 4a and Figure 4b** shows the results of the tests with 80/20 injection water/crude oils + solids. In order to get an indication of the oil removal from the sand, the crude oil was mixed with solids before the tests. The results of Figure 4a correspond to the test without fluid treatment (baseline). No crude oil solubilization is observed, as expected. The opposite occurred in the test with the treatment fluid, where the dark color of the aqueous phase is the result of crude oil solubilization in the core of the surfactant micelles (Figure 4b). As a result, the fine particles of sand look almost clean in the bottom of the graduated cylinder, because the oil was removed from the solids which proved the cleaning ability of the in-situ microemulsion treatment.

Table 1 Water injection used in the compatibility test

Injection water	
Density, lb/gal	8.3
Salinity, %	3.4
pH	6.62
Chlorides, ppm	100
Calcium, ppm	14
TDS, ppm	935
SO ₄ , ppm	2
Turbidity, NTU	9.8

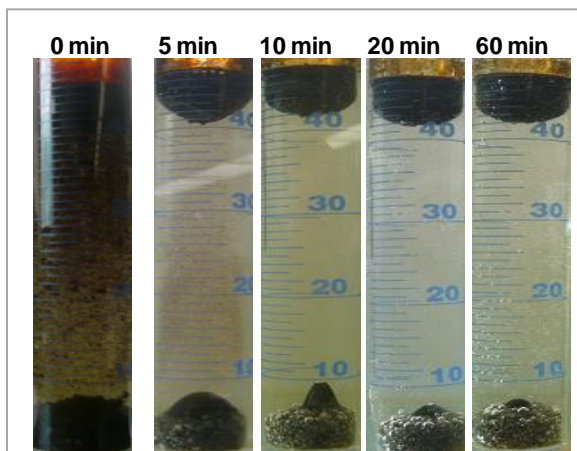


Fig. 4a Emulsion test without treatment fluid: (80/20 injection water /crude oil at 150°F)

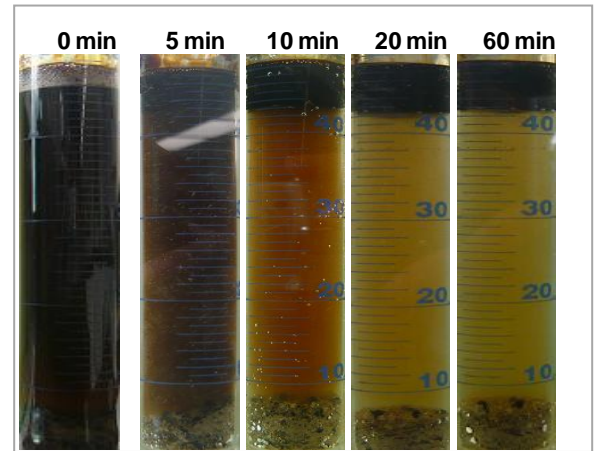


Fig. 4b Emulsion test with treatment: (80/20 injection water /crude oil at 150°F)

The fluid treatment was evaluated in a HTHP double-ended filter cell to determine its capability for cleaning the sand and changing the wettability of the solids from oil-wet to water-wet.

The cleaning test was carried out by depositing a cake formed by solids and crude oil on an aloxite disc which is then treated with the microemulsion fluid. The cake was built on an aloxite disc with 500 psi overbalance, for 3 hours, at constant temperature (**Figure 5a**). Then, the treatment fluid was placed on top of the cake and took about 40 minutes to collect all the filtrate and to clean the solids. The picture (**Figure 5b**) indicates that the crude oil was removed from the solids. Samples of the residual solids were placed in water to demonstrate their wettability. **Figure 5c** shows a photograph of the residual solids completely dispersed in water, which proved that the solids coated with crude oil (oil-wet) turned water-wet. All the crude oil was removed as can be seen in the pictures of the treatment fluid before and after the treatment (**Figure 6**).

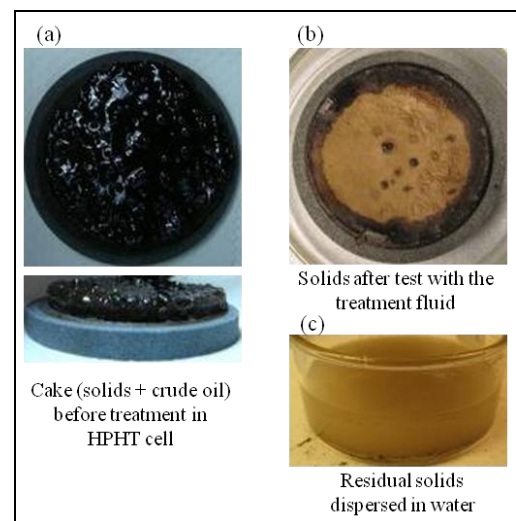


Fig. 5 Cake formed with solids and crude oil treated in a HPHT filtration cell

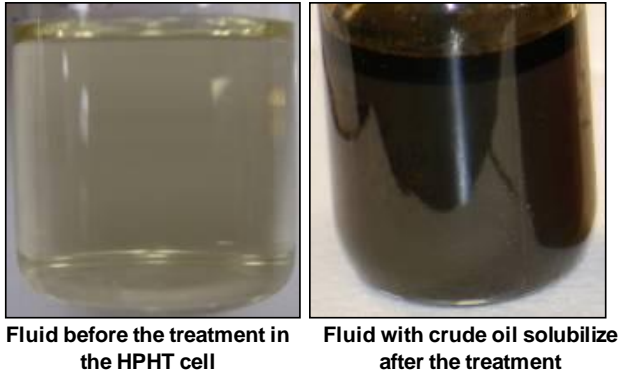


Fig. 6 Photograph of the treatment before and after treatment

Evaluation of Treatment Fluids for Stuck Pipe Application

Laboratory tests were performed to qualify the microemulsion fluids for an application of removal stuck pipe in a well drilled with in a non-consolidated sand formation with around 12 °API crude oil.

Figure 7 shows the results of the compatibility tests at 150°F. A 50/50 crude oil/in-situ microemulsion treatment fluid was mixed and the separation of fluids was recorded. The pictures show that almost total separation is reached in less than 5 minutes. This crude oil had emulsified water because the aqueous phase at the end of the test showed more than the 25 ml of the aqueous fluid used as treatment. This indicates that viscous emulsions formed downhole are rapidly broken with the right selection of treatment with surfactants.

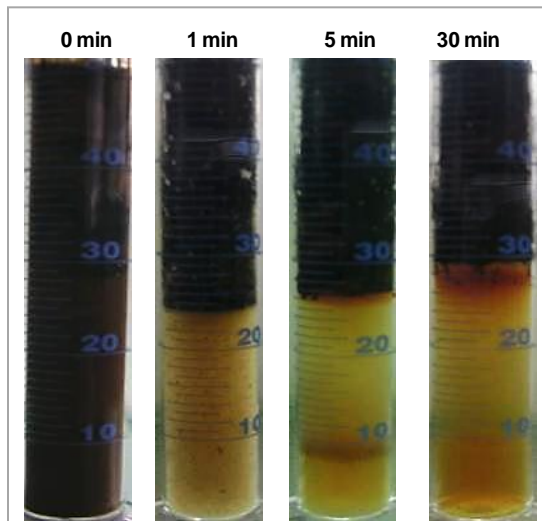


Fig. 7 Emulsion test between 12°API crude oil and treatment fluid

Figure 8a shows a photograph of the sludge from the field used for evaluation of the treatment fluids for stuck pipe. Figure 8b indicates that this sludge was rapidly dispersed when it was placed in the in-situ microemulsion fluid at room temperature (75°F).

This sludge was also evaluated in a HPHT cell. A cake was

formed for 3 hours at 150°F. Then, the treatment fluid was placed in the top of the cake and soaking occurred for 2 hours. Then, the outlet valve was opened and all of the treatment was collected in the filtrate (Figure 9). Upon removal of the disc from the cell, it was observed that the filter cakes were very clean.

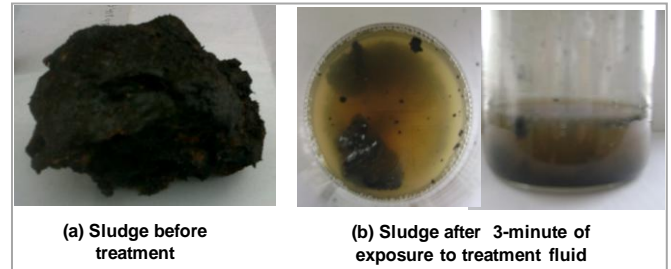


Fig. 8 Photographs of material used to evaluated treatment fluid for stuck pipe: (a) before treatment and (b) after treatment

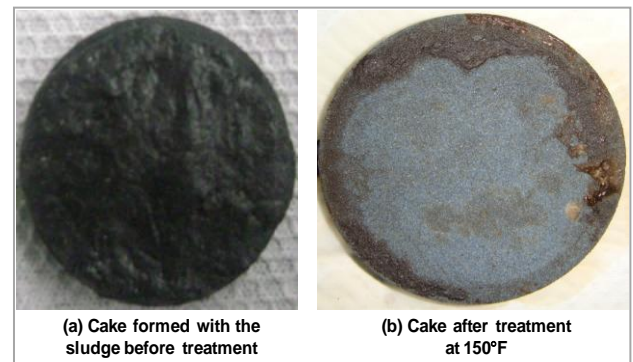


Fig. 9 Sludge evaluated in HPHT cell at 150°F: (a) before treatment and (b) after treatment

Field Applications

Case 1: Microemulsion Water Injector

An operator in Latin America wanted to perforate two heavy crude oil (12.3° API) zones with a BHT of 100-120°F and inject 14,000 barrels of production water per day without exceeding 1,450 psi of injection pressure. The maximum pressure target was established by the operator. Previously, in other areas in South America, this operator had very little or no success with their water injector programs.

To inject water into the two zones (20 ft) between 2,870 ft and 2,844 ft, it would be necessary to invade the zones with a fluid capable of removing the crude oil behind the production liner and cement. The large amount of oil and oil-saturated sand that needed to be solubilized and cleaned from the perforation required laboratory testing to prove the concept. Previous experience suggested that a good candidate fluid would be a customized microemulsion cleaning system. Results from the laboratory tests suggested that the microemulsion treatment could effectively solubilize the heavy crude oil and removing it from oil-wet sand surfaces. Additional testing also indicated that the treatment fluid was compatible with the crude oil, eliminating concerns for emulsion formation during the injection phase.

The microemulsion treatment fluid was pumped down the wellbore before perforating the production casing. By using this pre-emptive technique, the treatment fluid would enter the wellbore region beyond the cement at the moment of the perforation, removing potential hydrocarbon blockage and completely water-wetting the sand surfaces.

Figure 10 presents a summary of the target injection rate and the results obtained after the application of the microemulsion treatment. **Figure 11** shows the injection rate and pressure of the well after the perforation and during the injection phase, the pressure was gradually increased. After 7 days the expected and sustained injection rate of 15,000 BWPD was achieved. Furthermore, the increased water injectivity above the target rate occurred at a lower pressure, 1,170 psi versus 1,450 psi. According to the operator, the well can accept 20,000 BWPD but is limited by the amount of produced water generated in the field.

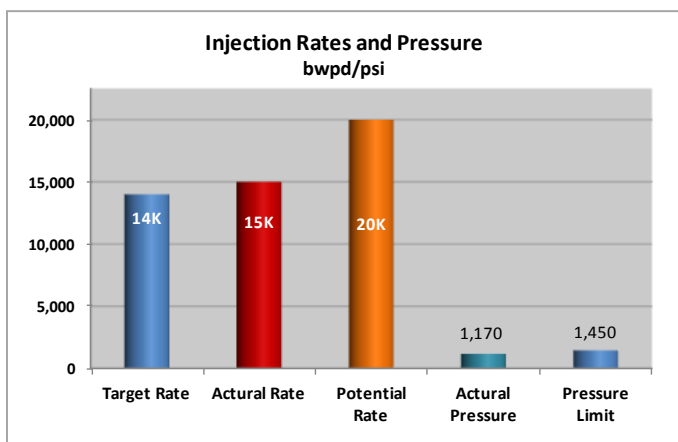


Fig. 10 Improved water injection after treatment

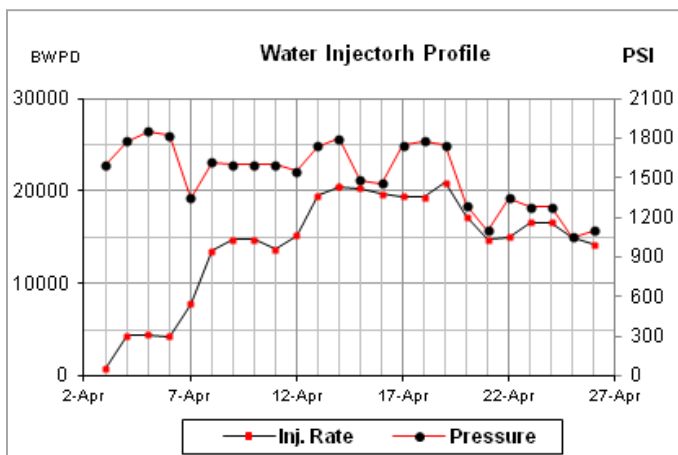


Fig. 11 Water injection performance vs. time

Case 2: Microemulsion Screen Remediation

An independent operator in the Llanos Basin of Colombia typically completes his highly permeable horizontal wells with pre-pack completion screens. Due to the nature of the heavy crude oil and the drilling fluid used to drill the reservoir,

screen damage is a common occurrence. Analysis of the produced crude oil suggested that asphaltene precipitation was one possible cause of screen plugging. In addition, compatibility studies between the heavy crude oil and the drilling fluid suggested that the mixing of these two fluids could cause further damage, not to mention additional damage caused by the drilling fluid filter cake.

Past remediation efforts with conventional mutual solvent-based treatments gave disappointing results, leaving the wells in an under-producing state. To improve post-remediation well performance, this operator commissioned a series of laboratory tests using crude oil and formation samples from the field to test a microemulsion as an alternative treatment. The primary objective of the testing was to determine if the microemulsion treatment fluid could (a) diffuse through pre-packed screen samples coated with the sludge material, (b) disperse the blocking material and (c) restore production to expected field levels (~350 BOPD).

After achieving promising results in the laboratory, the operator agreed to a field test to restore production in one of the failed wells. After developing a treatment procedure, the microemulsion treatment fluid was spotted inside the pre-packed screens and allowed to soak. After a short delay, to allow for diffusion, the well was put on line. The well began producing oil and gradually increased to 550 BOPD, a 63% increase over field expectations. In addition, the draw-down on the submersible pump was reduced by 25% and the water production was reduced from 65% to 35% (**Figure 12** and **Figure 13**).

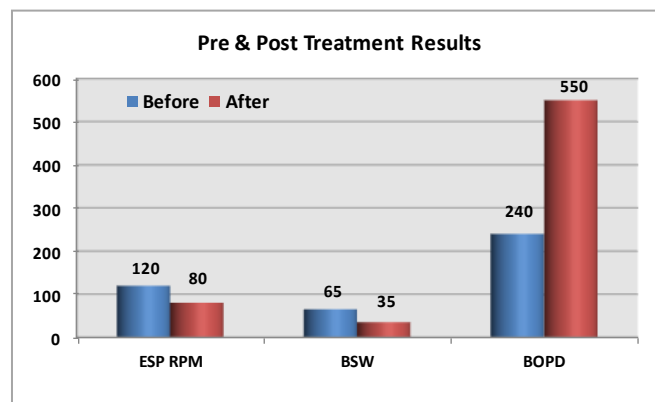


Fig. 12 Improved well performance after treatment

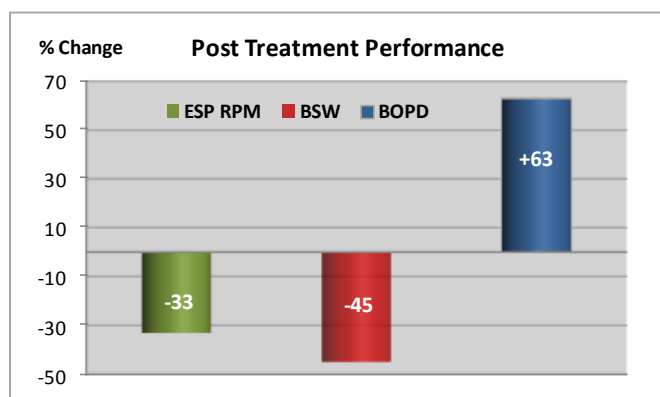


Fig. 13 Percentage change after treatment

Case 3: Microemulsion to Free Stuck Pipe

Another operator in Colombia, while drilling in a 87° pressure depleted, 12° API Gravity crude oil bearing, unconsolidated sandstone with a water-based drill-in fluid, experienced a series of stuck pipe incidences. In one case, stuck pipe occurred while navigating in the 6-1/8" interval 40 ft below the casing shoe. After making a connection, the pipe became stuck. Thinking the pipe was differentially stuck, diesel was bullhead down the workstring and into the annulus to reduce the hydrostatic pressure of the mud column and provide fluid lubricity to free the pipe. This technique was not successful. Next, while trying to work the drill pipe free and while circulating the drill-in fluid, a high volume of viscous sandy crude oil accumulations has been observed at the flowline and shakers. The decision was then mix and to circulate high viscosity water-based sweep to remove an accumulation of this material from the annulus. After deciding that this technique would not remedy the situation, a conventional stuck pipe remediation pill was spotted across the zone of interest and the pipe was worked for next 48 hours with without success.

After observing the continuous accumulations of thick, heavy crude oil and sand sludge at the surface and developing a better understanding what was happening when the drill-in fluid penetrated the suspect interval, the decision was made to pump a 20% v/v microemulsion-based pill in the annulus to the top of the BHA to thin and disperse trapped sludge responsible for the stuck pipe. The following steps were used:

1. All surface lines and pill tanks were cleaned.
2. 10 bbl of a 20% microemulsion-based pill as mixed in a pill tank.
3. The 10 bbl pill was pumped downhole, leaving 5 bbl inside the annulus and 5 bbl inside the pipe.
4. Once in place, 0.5 bbl of the pill in the pipe was pumped into the annulus every half hour.

In the first application, when the pumping process began, the drag on the pipe was 180K lbf and the torque was 15K lbf-ft. As each 0.5 bbl was pumped and entered the annulus, the torque and drag gradually decreased and after the last 0.5 bbl was pumped into the annulus, the pipe tension was reduced to 70K lb and the pipe became completely free.

On a similar well in the same field, a competitor mud company also experienced a stuck pipe incident. This well was an 87° inclination and the pipe was stuck approximately 80 ft below the casing shoe. Knowing the well was not differentially stuck, the operator decided to free the pipe using the microemulsion treatment fluid. The initial drag on the pipe was 260K lbf and the torque was recorded as 15K lbf-ft. In this well, 12 bbl of spotting fluid was pumped downhole, leaving 8 bbl in the annulus and 5 bbl in the drill pipe. A viscosity spacer was pumped to chase the treatment fluid downhole and was designed to carry the cuttings from the wellbore to surface when the pipe became free. After only one hour and pumping 0.5 bbl each half hour, the pipe became unstuck and drilling resumed.

In previous wells with stuck pipe, the operator was forced to kick off and perform a sidetrack operation. With the availability of a spotting fluid that is capable of reducing the viscosity of the heavy crude oil and sand sludge, the operator has a viable option to save non-productive time and the expense of sidetracking his wells.

Conclusions

Laboratory evaluations of the selected fluid treatment, using interfacial tension and fluids compatibility, confirmed that the fluid formulation used has the ability to remove damaging in-situ crude oil emulsions and to change the wettability of solids.

Phase behavior studies allow selection of the best surfactant blend system for formulations used to remove formation damage in injector and production wells

Field case applications proved that the surfactant blends, selected based on phase behavior and interfacial property measurements, are reliable fluids for (1) cleaning wellbore damage, (2) enhance injection to reach the maximum water injection potential of wells, and (3) free stuck pipe.

Acknowledgments

We thank the management of Baker Hughes for allowing us to publish this paper. Special thanks to W. Rojas, A. Vergel, A. Pardo, G. Bernal, Gianna Pietrangeli and the laboratory personnel in Bogota for their support in the field trial and the generation of laboratory data.

Nomenclature

<i>OBM</i>	=oil based mud
<i>SBM</i>	= synthetic based mud
°F	= temperature in Fahrenheit
<i>BOPD</i>	=barrels of oil per day
<i>BWPD</i>	= barrels of water per day
<i>Bbl/hr</i>	=barrels per hours
<i>Bbl</i>	= oilfield barrel, 42 gallons
<i>IFT</i>	= interfacial tension
<i>mN/m</i>	= milli Newton per meter
°F	= temperature in Fahrenheit
<i>Lb/gal</i>	= pounds per gallon
<i>ft</i>	= feet
<i>in</i>	=inches

%	=percentage
NTU	=Nephelometric units
Ppm	= part per million
lbf-ft	=pound-feet of torque
HPHT	=pressure high, high temperature
R&D	=research and development
° API	=API Gravity crude oil
BHT	= bottom hole temperature

References

1. Emiliani, C.N., Ripa, G., Sportelli, M., Cobianco, S., Del Gaudio, L., “SPE 94712, SPE European Formation Damage Conference, Scheveningen, The Netherlands, May 25-27, 2005.
2. Van der Zwagg C.H., “Benchmarking the Formation Damage of Drilling Fluids” SPE 86544, *SPE Production and Operations*, Volume 21, Number 1, pp 40-50, 2004.
3. Quintero, L., Jones, T. A., Clark, D. E., and Twynam, A., “NAF Filter Cake Removal Using Microemulsion Technology”.SPE-107499 presented at the European Formation Damage Conference held in Scheveningen, The Netherlands, 30 May–1 June 2007.
4. Quintero, L., Jones, T., Pietrangeli, G., “Phase Boundaries of Microemulsion Systems Help to Increase Productivity”, SPE 144209, SPE European Formation Damage Conference held in Noordwijk, The Netherlands, June 7–10, 2011.
5. Salager, J.L., Anton, R.E., Sabatini, D.A. et al. “Enhancing Solubilization in Microemulsions – State of the Art and Current Trends”. *Journal of Surfactants and Detergents* **8** (1): 3-21. 2005.
6. Ezrahi, S., Aserin A., and Garti N. “Aggregation Behaviour in One-Phase (Winsor IV) Microemulsion Systems”. In *Handbook of Microemulsion Science and Technology*, ed. P. Kumar and K. L. Mittal, 185-244. New York: Marcel Dekker, Inc. 1999
7. Bohlen, D.S., Vinson, P. K., Davis H.T. et al. “Generic patterns in the Microstructure of Midrange Microemulsions”. In *Organized Solutions, Surfactant Science Series*, ed. S. E. Friberg and B. Lindman, 145-158. New York: Marcel Dekker, Inc. 1992
8. Salager, J.L., Morgan, J., Schechter R.S. et al. “Optimum formulation of surfactant-oil-water systems for minimum tension and phase behavior”. *Soc. Petrol. Eng. J.* 19, 107-115. 1979.
9. Olsson, U. and Lindman B.; “Uni- and Bicontinuos Microemulsions”, in *The Structure, Dynamics and Equilibrium Properties of Colloidal Systems*, ed by D. M. Bloor and E. Wyn-Jones, Kluwer Academic Publishers, Netherlands (1990) 233.