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Development of a New Class of Frac Flowback Aids to Prevent Condensate Banking

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Abstract

Many gas condensate reservoirs experience significant productivity losses as the reservoir pressure drops below the dew point. This productivity loss is related to the liquid dropout in the vicinity of the wellbore and the subsequent decline in gas rate which is in turn associated with the reduction in gas relative permeability. Hydraulic fracturing is the most common stimulation method that has been employed to increase gas well deliverability after initial decline. The present work was concerned with the development of flowback aids for enhanced gas recovery after fracturing application on gas-condensate wells. The goal was to formulate microemulsion concentrates which form nanoemulsions when diluted into fracturing fluids and provide strong interfacial and surface tension reduction to prevent reservoir damage due to condensate banking.

Microemulsions have been formulated with various possible surfactants and condensate systems. The performance of the different formulations has been evaluated with different test methods, adopted from literature and industry best practice in order to screen for most promising microemulsion systems. These microemulsions were compared to their aqueous equivalents to determine the performance benefits offered by emulsified packages. High throughput experimentation and robotic formulation was utilized to screen several thousand formulations from nearly 50 different surfactant packages. Proppant regain permeability and coreflow testing were utilized on the best performing microemulsion formulations to determine the effect of field applications. The development of a new class of frac flowback aids that is made up of almost 100% renewable and environmentally friendly components has made a large step change towards chemical treatment methods utilizing flowback aids for condensate removal.

Introduction

Microemulsions are unique dispersions of oil in water or water in oil, stabilized by a surfactant and co-surfactant. The formation of such a mixture was first reported by Hoar and Schulman in the 1940s when they noticed a mixture of hydrocarbon and surfactant turned milky to clear on the addition of alcohol [1]. Schulman and his colleagues introduced the term “microemulsion” in 1959 [2]. The ability of microemulsions to simultaneously solubilize either aqueous or organic components while remaining isotropically clear and thermodynamically stable attracted much attention, particularly in the 1970s for use in enhanced oil recovery. Microemulsion can be described as system containing water, oil and amphiphile which is a single optically isotropic and thermodynamically stable liquid solution [3].

Microemulsions are dynamic systems in which the interface is continuously and spontaneously fluctuating [4]. Structurally, they are divided in to oil in water (o/w), water in oil (w/o) and bi-continuous microemulsions. In w/o microemulsions, water droplets are dispersed in the continuous oil phase while o/w microemulsions are formed when oil droplets are dispersed in the continuous aqueous phase. In systems where the amounts of water and oil are similar, the bi-continuous microemulsions may result [5]. The mixture of oil-water and surfactants is able to form a wide variety of structures and phases depending upon the proportions of components [6].

There are four types of microemulsion phases that exist in equilibria; these phases are referred as Winsor phases:

- Winsor I: With two phases, the lower (o/w) microemulsion phases in equilibrium with the upper excess oil.
- Winsor II: With two phases, the upper microemulsion phase (w/o) microemulsion phases in equilibrium with lower excess water.
- Winsor III: With three phases, middle microemulsion phase (o/w plus w/o, called bicontinous) in equilibrium with upper excess oil and lower excess water.
- Winsor IV: In single phase, with oil, water and surfactant homogenously mixed.

During the past decade microemulsions have gained more interests in hydraulic fracturing [7, 8]. It has been demonstrated that wells treated with fluids containing microemulsion flow back aid additives were more productive than well treated with traditional surfactants. Success of microemulsion flow back aids has been attributed to strong surface modification and lowering capillary pressure, changing wettability, lowering hydrocarbon/water interfacial tension and extending adsorption on reservoir rocks. Several commercial microemulsion flow back aids have been introduced to the market, which were defined as complex formulations consisting of surfactant, co-surfactant, mixture of solvents and water. Enhancing the penetration and cleanup of water based frac fluids and allowing higher fluid return and hydrocarbon production are among common attributes to such additives. This paper is an attempt to address some key aspects in evaluating microemulsion formulations to enhance condensate baking removal by hydraulic fracturing and presents a new class of microemulsion package that is made up of almost 100% renewable and environmentally friendly components. The work has made a step change towards the state of the art of this class of flowback aids.

Experimental

Condensate Samples

The condensates used for in laboratory evaluations were collected from Eagle Ford or Haynesville formations in Texas. As shown in a comparative GC analysis, the Condensate 1 used for the formation response and regain permeability testing had a relatively lower concentration of C12+ alkanes compared to the condensate 2 and 3 comprising higher hydrocarbon chains of up to C30.

Carbon Profile using High Temperature Gas Chromatography

All measurements were done on a Agilent 7890 Gas Chromatograph with an FID detector and equipped with universal Programmable Split-Splitless (PSS) and Programmable On-Column (POC) injectors design. The instrument was interfaced with a desktop computer running with ChemStation software to handle the integration and reports. Separation was achieved on an Elite Series GC capillary column (# 145-1009) of 5m x 0.53mm size and 0.10 μm film thickness. Condensate samples were dissolved in carbon disulfide (spectranalyzed grade from Fisher Scientific) and 0.5 μL of this solution was injected into the device. A temperature programing from 50 °C to 430 °C at 10 °C/min was applied. This method can measure % paraffin from C10 to C100 in hydrocarbon samples, while C<10 molecules are reported as a total sum.

Surfactant Flowback Aids

New surfactant packages optimized for condensate banking conditions and a commercial surfactant system have been evaluated in this study. The new renewable and environmentally friendly surfactant packages were formulated into an aqueous and microemulsion system with identical surfactant contents. A basic description of surfactant formulations used as flowback aids in this work is summarized in Table 1. Products were used at a concentration of 1L per 1000L of frac fluids, also cited as one gallon per thousand gallons of fluid (1gpt), or otherwise stated.

Table 1. Description of surfactant formulations used in this work.

Chemical Identifier	**Description**
SFBA-1	Commercial Surfactant Blend for Condensate/Water Removal
SFBA-2	New Surfactant Package Optimized for Gas-Condensate
SFBA-3	New Surfactant Package Optimized for Gas-Condensate
MESBA-2	Microemulsion of New Surfactant Package 2 Optimized for Gas-Condensate
MESFBA-3	Microemulsion of New Surfactant Package 3 Optimized for Gas-Condensate
MESFBA-4	Microemulsion of New Surfactant Package Optimized for Gas-Condensate

Surface and Interfacial Tension Measurements

All surface tension measurements were done on a Krüss K100C-Mk2 Tensiometer using the Wilhelmy plate method at room temperature. 0.1 gram of each surfactant product was measured and then brought up to 100 gram using DI water, or KCl brines. The solution was allowed to stir for 10 minutes in order to ensure homogeneity. Solutions were passed through a 0.45 micron filter before measurement. Interfacial tension measurements were conducted via Drop shape Method using a TECLIS Tracker H by fitting the shape of the drop (in a captured video image) to the Young-Laplace equation. Measurements were done in triplicate and an average reported for each surfactant solution.

High Throughput Experimentation

For evaluation of characteristics and phase diagrams of renewable and environmentally friendly surfactants, High Throughput Experimentation (HTE) was utilized to formulate microemulsion with different oils and surfactants. The experiments were carried out on a “Swing Emulsifier” platform provided by Chemspeed. Automated high output solutions enhance efficiency and productivity for experimental workflows and is displayed in Figure 1. As indicated, it consisted of a gravimetric dispenser unit, a four needle head liquid dispenser unit, racks for the formulation flasks (which itself was on a shaking frame used for mixing the formulations), the compound reservoirs and a capper/crimper device.

The exact data for each dispensing step is registered in a log file which can be exported into a excel spread sheet. With the gravimetric dispenser unit the composition of each sample is always known regardless the error compared to the specified amount. Depending on the sample composition, the time for preparing one sample is between 3 and 6 min. For example, for a set of experiments when composition is restricted to about 40% aqueous phase, 20% oil phase, 5% co-solvent and 35% surfactants mixture, the whole pack of 300 samples can be prepared and measured in 36 hours. In this work, high throughput experimentation and robotic formulation were utilized to screen several thousand formulations from nearly 50 different surfactant packages.

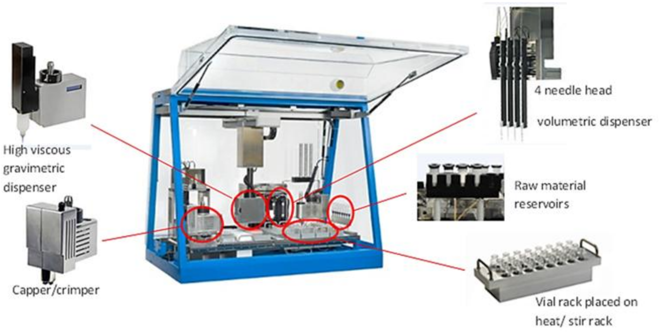


Figure 1. Image of "Swing Emulsifier" platform and robotic tools used for the microemulsion formulations

Surfactant Adsorption Test

Adsorption of surfactants on kaolinite, silica flour and calcium carbonate was studies for solid-liquid under equilibrium condition. 0.5 g of solid was mixed with 100 mL of brine containing 1gpt of surfactant systems at 50 °C for a given period of time. Measuring the change in surface tension of the effluent from solid-liquid slurry acts as an indication of the adsorption of surfactant onto the solid phase. If the surface tension quickly increased, it would indicate that the surfactant is removed from solution due to rapid adsorption onto solid phase.

Zeta Potential Measurement

Zeta potential values of fine silica flour, kaolinite and calcium carbonate were determined by microelectrophoresis on a Brookhaven Nanobrook 90PLUS PALS analyzer. The solids analyzed had a size between 3 and 20 microns. To measure the particle electrophoretic mobility, this instrument uses a phase analysis light scattering (PALS) based on the shifted frequency spectrum. Square cuvettes of 10 mm (Brookhaven Instruments Corporation BI-SCP) with a sample holding capacity of 4.5 ml were used to hold the samples. The colloidal suspensions were then illuminated by a cross focused laser beam. Zeta potential for each sample was determined by taking the average of 3 cycles (with 10 runs per cycle). The concentration of solids was set at 5 g/L of brine solutions with pH adjusted to 4, 7 or 10 by addition of HCl or NaOH. Brine solution contained 1 gpt of each surfactant system. Samples were allowed to reach the steady state by standing for 15 hours before measurement.

Core Flow Test

Laboratory core flow studies were performed using PMAC Systems coreflood apparatus to evaluate the interactions of several chemistries which may affect the stability/migration of clay minerals in Berea core upon flowing deionized water after saturation with synthetic laboratory seawater. As a substitute for field core, Berea sandstone core plugs sourced from Cleveland quarries, Ohio, were used for each core flow test. Each plug was cut to approximately 1½" diameter and 3" length with a permeability range between 100 and 200 mD. Mineralogy of core sample is given in Table 2.

Table 2. Mineralogy of core sample

Mineral Phase	**Content**
Quartz	86%
Kaolinite	5%
Feldspar	3%
Chlorite	2%
Calcite	2%
Dolomite	1%
Illite	1%

Berea sandstone was conditioned by vacuum saturating with a 0.51 M NaCl solution followed by a 1 M NaCl of pH 2 to 3 to remove most of the carbonates, then flowing 0.51 M NaCl at pH ≈ 7.2 The core permeability was calculated by measuring the pressure drop across the core at varying flow rates with the injected fluids passed through a 0.22 µm filter before injection to remove suspended solids. The sodium ions neutralize the negatively charged clay particles in the matrix minimizing the detachment of clay particles from the rock, thus reducing clay dispersion, and preserving permeability. This brine conditioned core was then exposed to fresh water at pH = 2 and showed no decline in permeability. Increasing the pH to 9 showed a reduction in permeability, and at pH above > 11 a rapid and drastic decrease in the permeability was shown which equated to water shock.

Proppant Regain Test

A threaded standard ChromaFlex glass column 30 cm long with an internal diameter of 2.5 cm was used. Each end is supplied with two PTFE end fittings with 20 µm porosity polyethylene bed supports to prevent fines form the sand pack from plugging the line. Samples of 16/30 CarboProp ceramic proppant were used to pack the column. A 71.3 g fluid mixture of 10% KCl and 10% condensate comprising 1gpt of flow back aid were prepared and mixed on a stirring plate. This solution was then added to the glass column and the remaining space filled with the proppant. The exact amount of fluid recovered is determined by measuring the amount of liquid regained back on a tarred beaker. The air flow rate was set at 100 mL/min and the amount of regained fluid was measured at 2, 5, and 10 min intervals. A test was deemed complete when no change in fluid recovery was observed (less than 0.1 g within 5 min).

Results & Discussions

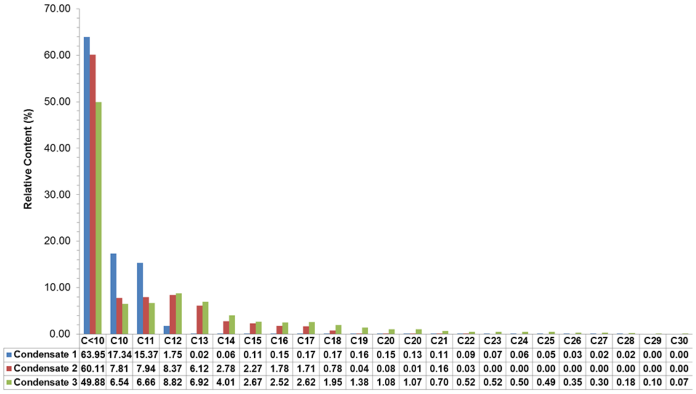
Many gas condensate reservoirs experience significant productivity losses as the reservoir pressure drops below the dew point. This productivity loss is related to the liquid dropout in the vicinity of the wellbore and the subsequent decline in gas rate which is in turn results in a reduction in gas relative permeability. The decrease in well production is often attributed to condensate accumulation (banking) and water blocking. The liquid condensate continues to accumulate, occupying portions of the rock that would otherwise be available for gas flow and thus impedes the flow of gas until a critical liquid saturation is reached. Once the critical liquid saturation is exceeded, both the condensate and gas flow towards the wellbore, but condensate continues to accumulate until a steady state saturation is reached that is somewhat higher than the critical condensate saturation. Similar effects are experienced with water blocking.

Chemical treatments using either solvents or wettability alteration agents have been studies and have given very promising results. In an approach, Li and Firoozabadi [9] examined the alteration of wettability of intermediate gas-wetting by chemical treatment of the rock. A major factor in liquid accumulation is the liquids low permeability because of strong liquid wetting. By altering wettability of the rock from liquid wetting to intermediate gas wetting, an increase in liquid mobility is achieved preventing accumulation of liquid in high saturations and results in high rate of gas production. Kumar et al. evaluated fluorinated surfactant made by 3M using a methanol-water mixture as the solvent to treat cores under reservoir conditions [10]. Authors reported significant increase in the steady state gas and condensate relative permeability. In this study, we evaluated use of microemulsion flowback aids with hydraulic fracturing as an alternative and more cost-effective method to remediate condensate banking.
Three condensates were examined from Eagle Ford and Haynesville fields in Texas. Some physical properties of condensate samples are given in Table 3.

Table 3. Characteristics of condensate samples used in this study.

Sample ID	**Density (g/cm^3)**	**Surface Tension (mN/m)**	**WAT (°C)**
Condensate 1	0.7463	23.6	25.4
Condensate 2	0.7978	25.0	25.3
Condensate 3	0.8185	26.2	25.6

High temperature gas chromatography (HTGC) was used to quantitatively and qualitatively resolve n-paraffin distribution in condensate samples and results are shown in Figure 2. Variation in surface tension of condensate maybe attributed to the differences in alkanes distribution, however Wax Appearance Temperature (WAT) does not follow paraffin profiles. Condensate 3 contains 9.2% C18+ hydrocarbons but due to high solubility of higher paraffin molecules in C<18 fraction, it exhibits the same WAT as for condensates 1 & 2. Condensate 1 is the lighter sample with lowest surface tension. Interfacial tension of the samples was determined using drop shape analysis method on a TECLIS Tracker H tensiometer. As given in Table 4, Condensate 1 has highest IFT compared to other samples. This is further demonstrated by photographs from interface of water-condensate of the samples (see Figure 3), in which Condensate 1 showing convex curvature at the interface.



	C<10	C10	C11	C12	C13	C14	C15	C16	C17	C18	C19	C20	C20	C21	C22	C23	C24	C25	C26	C27	C28	C29	C30
Condensate 1	63.95	17.34	15.37	1.75	0.02	0.06	0.11	0.15	0.17	0.17	0.16	0.15	0.13	0.11	0.09	0.07	0.06	0.05	0.03	0.02	0.02	0.00	0.00
Condensate 2	60.11	7.81	7.94	8.37	6.12	2.78	2.27	1.78	1.71	0.78	0.04	0.08	0.01	0.16	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Condensate 3	49.88	6.54	6.66	8.82	6.92	4.01	2.67	2.52	2.62	1.95	1.38	1.08	1.07	0.70	0.52	0.52	0.50	0.49	0.35	0.30	0.18	0.10	0.07

Figure 2. Carbon distribution of condensate samples as determined by HTGC.

Table 4. Interfacial tension of condensates in KCl solutions at temperature of 50 °C.

Sample ID	99% Carbon Chains	IFT (mN/m)		
		0% KCl	5% KCl	10% KCl
Condensate 1	≤ C 12	39.7	38.9	36.5
Condensate 2	≤ C 20	10.5	10.5	10.5
Condensate 3	≤ C 30	24.9	20.0	17.3

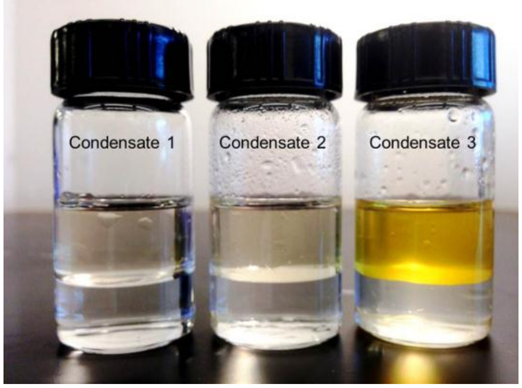


Figure 3. Condensate and their interface with 10% KCl brine.

Foamability of condensates was also studied as an indication for gas-condensate emulsion phase stability. Pure condensate liquid was purged with nitrogen gas (at 0.5 L/min) until a stable foam height was achieved. Once gas flow was stopped, foam life (in seconds) was measured as the time to reach initial condensate volume. Presence of natural surfactants (in this case, hydrophobic/oil soluble surfactants) and asphalthenes are known to contribute to foaming tendency of hydrocarbon fluids. Condensate 1 was found to be very different than other samples by lack of tendency to foam. By analogy, the high IFT of Condensate 1 can be attributed to the absence of water soluble natural surfactants.

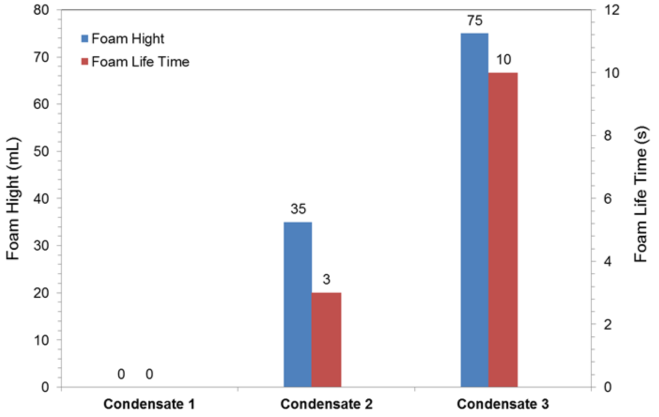


Figure 4. Foaming tendency of native condensate samples. Condensate 3 shows highest foaming characteristic.

Various surfactant chemistries were evaluated to lower interfacial tension of condensate-brine system. Table 5 gives the results for a few aqueous and microemulsion surfactant flowback aid formulations. In general new surfactant formulations developed for condensate banking provide higher IFT reduction when compared to the commercial product SFBA-1.

Table 5. Interfacial tension (mN/m) of condensate in 10% KCl brine containing 1gpt of surfactants measured at 50 °C.

Surfactant	**Condensate 1**	**Condensate 2**	**Condensate 3**
Blank	36.5	10.5	17.3
SFBA-1	6.2	1.9	2.1
SFBA-2	2.4	1.6	1.4
SFBA-3	1.3	<1	1.6
MESFBA-2	2.0	1.5	2.1
MESFBA-3	2.5	<1	1.2
MESFBA-4	2.8	<1	2.4

To better assess the effectiveness of surfactant formulations, proppant regain permeability testing was conducted. Condensate 1 was used in this evaluation since it exhibited least foaming and highest IFT compared to other samples. A mixture of 10% Condensate – 90% Brine (10% KCl solution) was allowed to flow over a column packed with 16/30 CarboProp ceramic proppant under a stream of nitrogen gas (0.1 L/m).

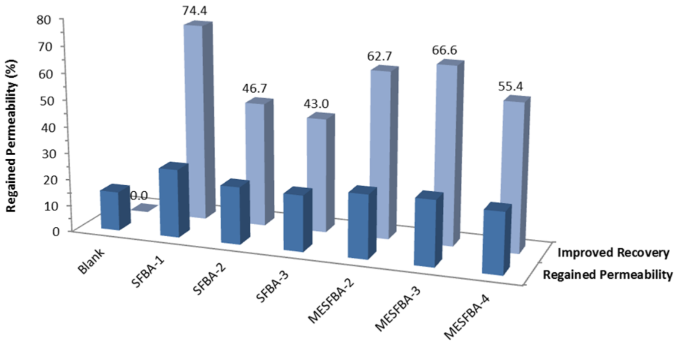


Figure 5. Regained permeability and improved recovery of Condensate 1 with surfactant systems.

Results are graphically presented in Figure 5. Reported improved recoveries were calculated based on the following formula:

$$Improved\ Recovery\ = 100\ x\ \frac{[(Regained\ volume\ (sample) - (Regained\ volume\ (blank)}{Regained\ volume\ (blank)}$$

Commercial product SFBA-1 shows a high recovery rate which can be attributed to high foaming nature of the surfactant chemistry used in the formulation. It was also found that microemulsion formulations provide better performance compared to equivalent aqueous surfactant systems (notice to improved recoveries for SFBA 2 & 3 versus MESFBA 2 & 3). Among the new environmentally friendly products, MESFBA-2 and MESFBA-3 exhibited higher promise to be used as flowback aids for condensate banking removal.

One of the key properties of flowback aids is to alter surface properties of reservoir minerals. To do so, surfactants must be adsorbed onto the surface of reservoir minerals. Adsorption of MESFBA-2 and MESFBA-3 onto kaolinite, silica flour (fine quartz) and calcium carbonate was determined.

Results are graphically presented in Figures 6 & 7. Both MESFBA-2 and -3 exhibited high adsorption on kaolinite. Adsorption on silica and calcium carbonate was found to be higher for MESFBA-3 formulation. All solid fines used had a D(50) of less than 5 microns (see Figure 8), however, clay minerals are known to have high surface area and high tendency to adsorb organics which can results in higher surfactant adsorption rates.

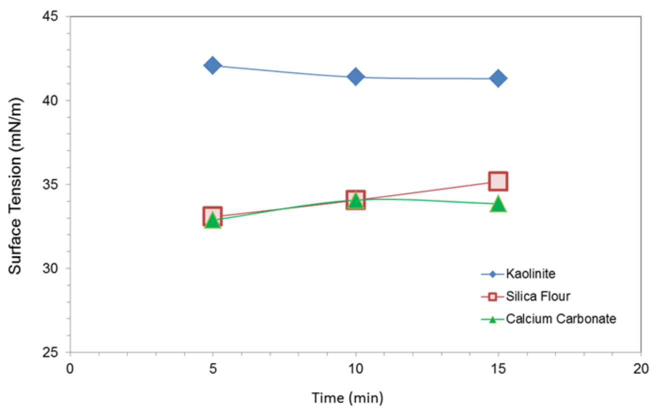


Figure 6. Adsorption of MESFBA-2 on solid minerals in a solution containing 30 ppm of flowback aid (Surface Tension of 33.5 mN/m) at 50 °C.

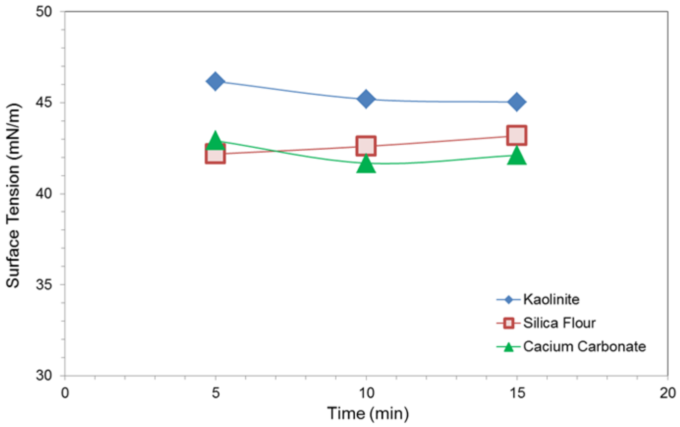


Figure 7. Adsorption of MESFBA-3 on solid minerals in a solution containing 50 ppm of flowback aid (Surface Tension of 35.1 mN/m) at 50 °C.

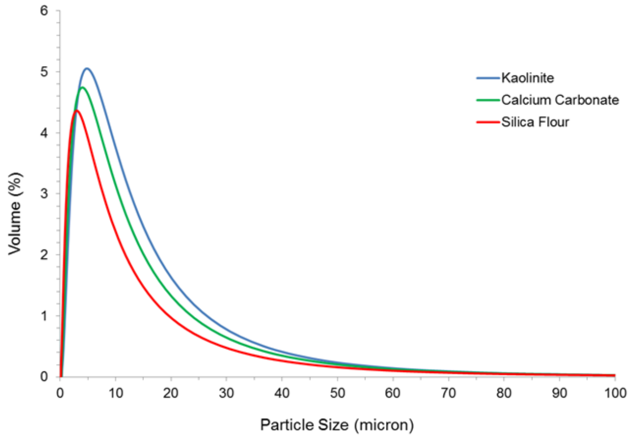


Figure 8. Particle size distribution of solids used for surfactant adsorption test.

Fines migration is a process which results in a reduction of the flow capacity of an oil, water or gas bearing formation by the internal movement of fines particles within a rock’s pore structure with the problem exacerbated at the near wellbore region [11]. It is a global challenge that is endemic to hydrocarbon production, with numerous fields suffering from this problem. Fines can cause a severe reduction in reservoir permeability due to their tendency to arrive at and plug interconnecting pore throats. If pore throats become blocked then the permeability of the reservoir will be reduced, causing operational and economic problems due to the reduction of the oil and gas productivity of reservoirs. For instance fines migration can drop very permeable sandstones to less than 1% of their original permeability in a few hours of flow or less. Symptoms of fines production in the reservoir are a rapid production decline and occasional fines production to the surface. This damage is irreversible and needs to be removed by acid stimulation.

A water wet surface prefers to be in contact with a water phase rather than an oil or gas phase, therefore water wet rocks preferably imbibe water compared to oil. Typically fines are water-wet and with the onset of water production they become very mobile, therefore the introduction of water can trigger fines migration. If the clay particles become oil-wet, or partially oil-wet due to some external influence, the fines and clay particles then become attracted to and immersed in the oil phase and the particles tend to move with the oil with the resultant plugging of pore throats being quite severe. During two-phase flow of oil and water, fines tend to migrate because the water is mobile enough to carry the fines. Turbulence caused by this multi-phase flow keeps fines mobilized until they plug at restrictions. This turbulence tends to increase near the wellbore due to radial flow effects and it is this area of the reservoir where damage is greatly magnified.

Today, a hydraulic fracturing job often comprises a few stages including injecting a pre-pad, a pad, a proppant containing frac fluid and finally a treatment with flush fluids. In a typical frac jobs, 2 to 10 million gallons of water is injected downhole in the form of frac fluids comprising various chemicals. A fractured well does not reach its maximum production potential until the frac fluids are completely removed and displaced by formation fluids. Some of this water is lost in the formation, but 25 to 70% of it returns to surface within 1 to 3 months. A challenge in hydraulic fracturing, especially for tight and shale formations, is associated with remediation of formation damage caused by frac fluid invasion into the porous media of the reservoir, formation of oil/water emulsions and clays and fines migration.

To demonstrate impact of fine migration on reservoir permeability, we conducted coreflood testing using Berea sand stone containing 5% kaolinite. The injection of 5% NaCl at a flow rate from 0.2 to 3.0 mL/min at ambient temperature showed no negative impact on the permeability of the core.

This was illustrated by the differential pressure remaining stable for the duration of this flow. Changing to deionized water at 69300 sec at a flow rate of 3.0 mL/min resulted in the differential pressure increasing rapidly after 15 minutes (at 70200 sec). When the direction of flow was changed from forward to reverse at 70500 sec, the differential pressure quickly increased again to over 600 psi demonstrating that the flow was being blocked by clay particles moving between pore constrictions in either direction (see Figure 9).

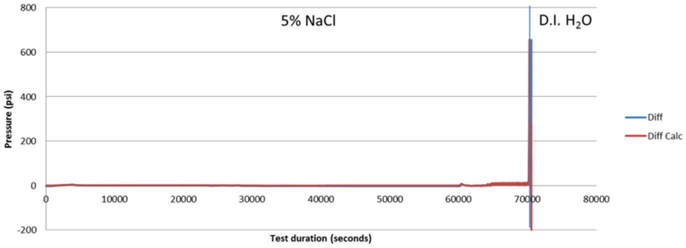


Figure 9. Coreflood analysis of Berea sand stone showing clays deflocculation/migration upon change in fluid salinity.

In this work, we utilized zeta potential measurements to study interaction of surfactant formulation with clay minerals. The Zeta potential is defined by the charge that develops at the interface in the boundary of hydrodynamic shear between solid surfaces as product of the electrostatic repulsion and the attractive forces related to the Van Der Waals Forces. Zeta potential can be affected by changes in pH, conductivity of the medium (salinity and kind of salt) concentration of particular additives (polymer, surfactants, etc.). Zeta Potential values comprehended (-20 and 20 mV) reflects the effective charge is low enough in the particles that the repulsion between them are lowered to one point where flocculation, coagulation and aggregation could occur [12] resulting in low risk in clays and fines migration.

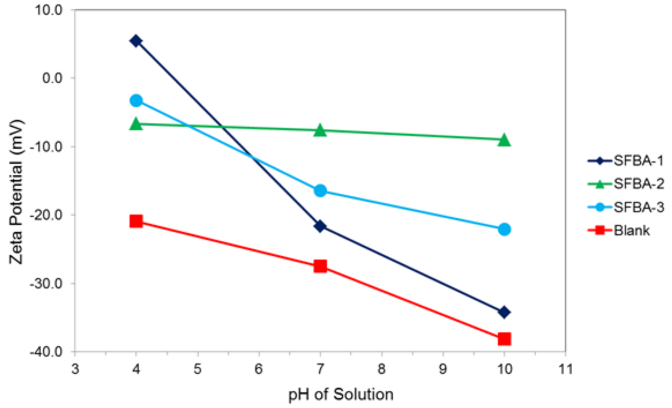


Figure 10. Zeta potential of Kaolinite in 0.5% KCl brine with 1gpt of SFBA products.

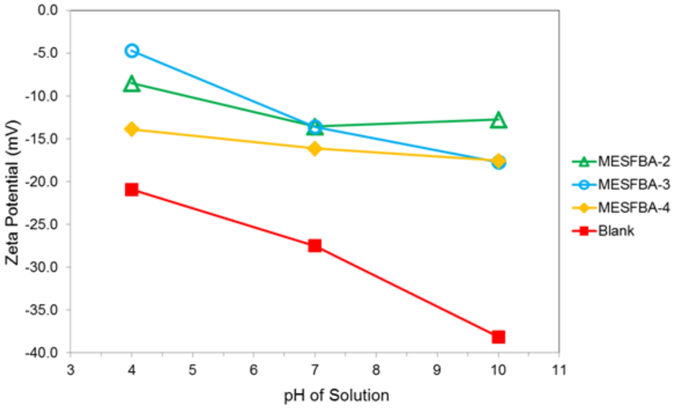


Figure 11. Zeta potential of kaolinite in 0.5% KCl brine with 1gpt of MESFBA products.

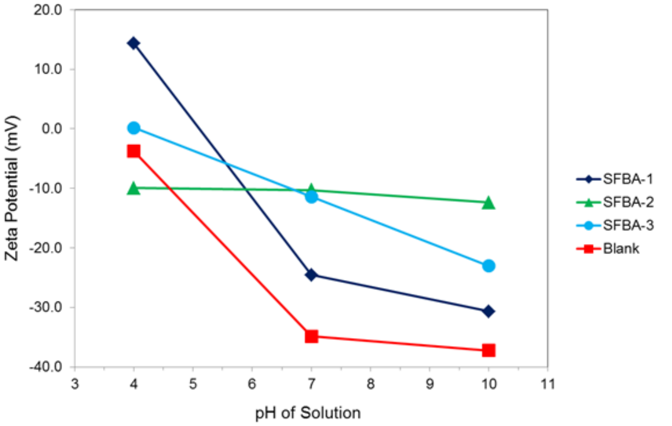


Figure 12. Zeta potential of fine silica in 0.5% KCl brine with 1gpt of SFBA products.

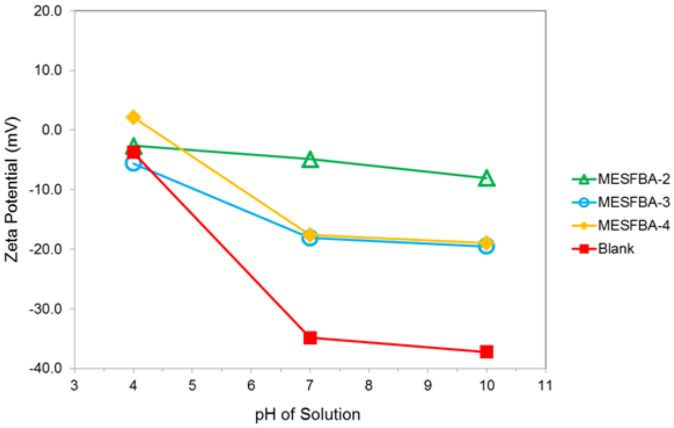


Figure 13. Zeta potential of fine silica in 0.5% KCl brine with 1gpt of MESFBA products.

Zeta potential measurements (see Figures 10 to 13) at pH 4, 7 and 10 clearly demonstrates that use of commercial surfactant SFBA-1 in frac fluid could potentially increase clay and fine migration due to destabilization of particles by increasing negative charge on their surface. Among new surfactants systems developed in this work, microemulsions show lower risk for clay migration compared to their equivalent aqueous surfactant formulations.

Conclusions

The following conclusions may be drawn according to the results obtained in the present study:

1) The development of a new class of frac flowback aids that is made up of almost 100% renewable and environmentally friendly components has made a step change towards chemical treatment method for condensate banking. High throughput experimentation allows screening of a few hundreds formulations in a relatively short period of time.
2) Microemulsion surfactant formulations offer more benefits and higher performance compared to their equivalent aqueous formulations, indicating better interfacial activity to be achieved during hydraulic fracturing.
3) Flowback aids may be further improved based on characteristics of reservoir fluids (condensate and formation brine). More studies are required to better correlate treatment efficacy versus condensate chemistry and reservoir conditions.
4) Multiphase flow in porous media is complex and governed by several factors including the formation geochemistry, complex pore structure of the medium and how it affects the distribution, flow, displacement of one or more fluids, or dispersion of one fluid in another.
5) Surfactants, regardless of their mode of state: aqueous or microemulsion, can interact with such phases and disturb the equilibrium under which they exist, thus affecting the dynamics of multiphase flow during well production. In order to achieve higher production rate and reduce fluid blocking, such interactions must be engineered to cohesively work together.

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