EVALUATION OF SURFACTANT WITH THIN FILM SPREADING MECHANISM FOR EOR IMPLEMENTATION

EVALUASI SURFAKTAN DENGAN MEKASISME PENYEBARAN LAPISAN TIPIS UNTUK IMPLEMENTASI EOR

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ABSTRAK

Sifat kebasahan memegang peranan penting pada aliran dua fase di dalam media berpori. Efisiensi pendesakan minyak oleh fluida juga ditentukan oleh karakteristik sifat kebasahan dari batuan reservoir. Tulisan ini berisi paparan tentang modifikasi sifat kebasahan reservoir dengan injeksi surfaktan TFSA (*Thin Film Spreading Agent*) untuk aplikasi EOR melalui kajian laboratorium. TFSA yang digunakan pada percobaan ini disebut Coconut Ethanolamide dengan tingkat HLB (*Hydrophilic-Lipophilic Balance*) sekitar 13 sampai 15 di mana sangat cocok untuk tujuan TFSA. Beberapa evaluasi laboratorium telah dilakukan untuk menseleksi surfaktan ini dengan tujuan untuk mendapatkan sifat-sifat terbaik yang memenuhi kriteria injeksi kimia EOR. Kemudian uji larutan TFSA telah dikerjakan termasuk kecocokan dengan air formasi, ketahanan suhu, kelakuan fase, dan uji penyaringan. Hasilnya menunjukkan bahwa semua parameter uji cocok untuk injeksi kimia. Parameter lainnya yang mengukur interaksi fluida dan batuan contohnya: adsorpsi, sifat kebasahan, imbibisi, permeabilitas relatif, dan percobaan pendesakan baru inti telah dikerjakan untuk mendapatkan bilangan kuantitatif untuk penyaringan surfaktan ini. Semua hasil percobaan dapat dikategorikan sebagai tingkatan moderat kecuali adsorpsi sangat bagus. Meskipun hasil uji laboratorium menunjukkan TFSA ini valid untuk injeksi kimia, perbaikan dengan menambah bahan kimia disarankan untuk mendapatkan formula TFSA yang lebih baik.

Kata Kunci: Modifikasi sifat kebasahan, agen penyebaran lapisan tipis, injeksi kimia

ABSTRACT

Wettability plays an important role of two phase fluids flow in porous media. The displacement efficiency of oil by injected fluid is also dictated by wettability characteristic of reservoir rocks. This papers contents a highlight of the reservoir wettability modification by injecting TFSA (Thin Film Spreading Agent) surfactant for EOR applications through a laboratory study . TFSA used in this study is called Coconut Ethanolamide with a HLB (Hydrophilic-Lipophilic Balance) level around 13 to 15 which is very suitable for TFSA purposes. Several laboratory evaluations have been done to screen this surfactant with the aim of getting the best properties that fulfill the criteria for EOR chemical injection. Then TFSA solution tests have been carried out including compatibility, thermal stability, phase behavior, and filtration test. The results suggest that all measured parameters are suitable for chemical injection. Others parameters measuring rock fluid interactions for instance: adsorption, wettability, imbibition, relative permeability, and core flood experiments has been done to find the quantitative numbers for screening this surfactant. All experiment results categorize as moderate levels for passing the screening criteria for chemical injection except for the adsorption which is excellent. Even though the results of laboratory tests show this TFSA is valid for chemical injection, improvement by adding some chemicals is still suggested to find a better TFSA formula.

Keywords: Wettability modification, thin film spreading agent, chemical injection

I. INTRODUCTION

Relative permeability flow has been acknowledged significantly to affect two phase flow in a reservoir. The main factor, which dictates the relative permeability characteristics of two phase flow, is the rock wettability. Wettability effect on relative permeability, and it can be the main factor controlling position, flowing, and three-dimension distribution of fluid on the rock. Therefore, the relative permeability characteristics automatically would control the fluid flow in the reservoir and consequently determine the magnitude of the recovery factor of oil.

Wettability means that rocks relatively prefer to be wetted by a certain phase compared with to another. Rocks can be oil wet, water wet, and intermediate wets. In the strong oil-wet rock, oil distributed in the small pores or spreads out through the surface of rock in the form of thin film, and water occupies the centre parts of the large pores. On the other hands in the strong water-wet rock, water occupied the small pores or spread out through the rock surface as thin film, and oil is only filling up the larger pores. The relative permeability in the case of strongly water wet or oil wet system under certain saturation, high value when the flowing liquid is in the non wetting phase.

In oil wet rock in which water occupies the central parts of the large pores, then, water flooding initiated, the water injection will form water channels through the large pores and lead to water fingering and leave the oil unremoved in the surface of rock and the small pore. These phenomena can lead to premature water break through and relatively low oil recovery factor. To avoid this problem, wettability alteration using surfactant with thin film spreading agent mechanism can be proposed (Qingjie et al. 2010).

The mechanism of surfactant injection to improve oil recovery can be understood through the definition of a dimensionless number called "capillary number" (Nc). The increasing capillary number of several orders of magnitude can release the residual oil behind the capillary trap and make it flow into the well bore. The important mechanism of surfactant injection is also to change contact angle through wettability alteration (Rao et al. 2006). Theoretically Nc equation can be written as follow:

$$N_c = \frac{\mu\, \upsilon}{\sigma \cos\theta} \qquad (1)$$

Where N_c : capillary number, μ : viscosity, V: velocity, σ : interfacial tension (IFT), θ: contact angle

Based on the above equation, the parameters that can be changed very drastically without any negative effects on reservoir properties are IFT and contact angle. IFT could be reduced to the order of 10^{-4} dyne/cm. Moreover contact angle could be managed approaching 90 degree at which cosines θ approaches zero it means the value N_c approaches infinity value.

Since wettability strongly influences the distribution and flow of fluid in the reservoir, an accurate estimation of in-situ reservoir wettability is important for successful implementation of improved oil recovery process using chemical injection.

Anionic surfactants normally can change wettability of carbonate rock into intermediate/water wet condition. While cationic surfactants also have been reported capable for altering carbonate rock wettability into more water wet (Seethepalli et al. 2004). Nonionic surfactants have been investigated as well for altering the carbonate rock wettability from initially strongly oil-wet to a weakly oil-wet state (Vijapurapu et al. 2003). More findings reported that nonionic surfactant altered rock wettability from initially weakly water wet to a mixed wet state, while anionic surfactant can change wettability to a strongly oil wet state (Rao et al. 2006). A cationic surfactant has been reported that it can change a water wet reservoir to become oil wet, whereas as anionic surfactant can only cause minor change of its wettability (Li et al. 2004). Alteration of wettability to either mixed or intermediate-wet can improve oil recovery from even water-wet reservoir. For given set of conditions, the higher apparent viscosity required for mobility control in oil-wet versus water-wet reservoirs mean that greater quantities of chemicals will be needed in oil-wet system (Kremesec et al. 978) It is generally accepted that adsorption of polar compounds onto rock surface has a significant effect on the wettability alteration of reservoir rocks.

Experiments conducted to account for the wettability changes have been performed to use several methods such as: oil recovery of core flood experiments, relative permeability constructions, and contact angle measurements (Sugihardjo 2009). But so far, there are no comprehensive conclusions regarding the relationship between the type of surfactant and wettability nature (oil wet or water wet). The interaction between reservoir fluid/rock and every type of surfactant is very complex and difficult to predict. Therefore, detailed laboratory tests should be done to anticipate the wettability changes at any surfactant injection proposal.

It can be summarized that actually wettability of rock can be changed to be more water or oil wetted by adding some chemicals. This paper is presenting of wettability alteration phenomenon in which wettability of rocks can be modified becoming more water wet by adding some surfactant solution that has a thin film spreading mechanism. Therefore a typical surfactant having special properties should be selected in order to match with the above mechanism.

Surfactant Selection

Before finding surfactants for EOR pilot preparation that will be used as spreading agents, basically the surfactant characteristics such as spreading coefficient will be evaluated. This coefficient is indicative of the difference in the adhesive forces between liquid phase (such as water) and solid (rock) or liquid two (oil). Therefore, normally spreading coefficient can be written down as follows:

$$S=W_a-W_c \qquad (2)$$

Where: W_a is work of adhesion while W_c is work of cohesion.

Spreading coefficient may have positive or negative values according to the nature of rock surface and liquids present in the system. A positive spreading coefficient indicated that a thin film becomes a continuous phase through the substrate (Araujo et al. 2001). In the case of a water/oil/rock system, the water phase is able to spread on the water, the value of S must be positive to get a better spreading ability.

Another surfactant characteristic is called HLB. The HLB will determine the degree to which a surfactant will be soluble in oil or in water. The lower the HLB of surfactant is more lipophilic (oil soluble) while the high the HLB of surfactant is more hydrophilic (water soluble). Arbitrary scale of the HLB is from 0 to 20 (2). Based on the HLB and agent tendency, surfactants can be classified as follows (3):

- Anti-foaming agent (HLB=0-3)
- Emulsifying agent (HLB=4-6)
- Wetting/Spreading agent (HLB=8-18)
- Detergent (HLB=13-15)
- Solubilising agent (HLB=10-18)

Following the above HLB characteristics, surfactant with HLB value 8-18 should be selected to find an appropriate surfactant having wetting/ spreading agent properties for SP (surfactant polymer mixture)-EOR projects. A general term for this kind of surfactant is TFSA, which is normally added to the injecting fluid in EOR project to create thin film in the surface of rock and promoting wettability alteration from originally oil wet rock becoming more water wet.

In this experiment this kind of surfactant namely Coconut Ethanolamide has been selected with a HLB value around 13 to 15 which is very suitable for TFSA purposes. The chemical formula is RCON(AH2CH2OH)2 which is nonionic surfactant with excellent wetting characteristic. This surfactant contains 60% active surfactant. However, using this surfactant for EOR proposal further laboratory evaluation should be done to determine more detail the surfactant properties following the laboratory screening criteria that had been formulated in many references (Sugihardjo 2008).

II. METHODOLOGY

Methodology used in this laboratory examination will be divided into three steps to screen this surfactant to fulfill the EOR chemical screening criteria. These processes are to reduce the risks of mistaken and to assure of a successful pilot project of chemical-EOR. Those three steps are as follows:

- Sample characterization
- Solution Evaluation
- Rock-fluid interaction

A. Sample Characterization

For the purpose of EOR screening, some field samples should be taken those are rock sample from the target layer, formation water, and oil.

- The best sample for rock is preserved core to keep the wettability at the original condition and it has not to be exposed to the atmosphere. The rock will be analyzed for their composition using X-Ray diffraction analysis. Then, it will be plugged with the dimension of 3 inches long and 1.5 inches diameter. The basic data including porosity and permeability of each plug is measured to select the best core plug properties for further experiments.

- Formation water should be taken at the separator test with no contamination from other sources of water. It is brought to laboratory soon after taken and directly determine cations and anions constituent. Therefore it is important to understand the level of hardness and multivalent ions content in order to anticipate precipitations formation during solution mixing.
- The oil sample viscosity is measured to account the value of viscosity of polymer that can improve the fractional flow displacement at the core flooding experiment.

B. TFSA Solution Evaluation

The characteristic of surfactant solution is evaluated regarding the quality of the solution and also the important properties to assurance successful EOR project (Sugihardjo 2008). Those evaluations will include the following:

- Compatibility of injection water with surfactant, which is basically formation water may contain a high salinity and high hardness. This kind of water could weaken the surfactant properties and create precipitation. The compatibility test should produce a solution without any precipitation and coagulation.
- IFT measurement; this parameter is not actually very important and does not need to be 10^{-3} dyne/cm but it also should not be very high.
- Phase behavior of surfactant solution mixed with the reservoir oil; again this parameter also should not create Winsor type 3 or middle micro-emulsion but at least Winsor type 1 or water phase micro-emulsion is sufficient
- Thermal stability; the surfactant solution should have a capability to withstand staying in the reservoir at high pressure and temperature at stable condition for a period of time at least 1 month or more depending required to ensure the residence time from injection to production wells.
- Filtration test is to guarantee that surfactant solution could pass through the sand face easily without any restriction. The test is done by filtration method using 0.22 micron filter paper. The flow of solution should be gently without any plugging.

C. Rock-Fluid Interaction

There are several parameters used to indicate the interaction between TFSA solution with the reservoir rock including dynamic and static parameters for instance: Adsorption, wettability change, imbibition, relative permeability, and core flooding experiments. Surfactant solution has only a capability to develop microscopic displacement during flooding. After that, the accumulation of displaced oil will form an oil bank at which a polymer solution must be added to improve macroscopic displacement efficiency. Therefore, a polymer solution is also prepared in this experiment to support the TFSA surfactant in the core flooding.

- Adsorption test, this test is to know the adsorption level of surfactant onto the surface of the rock, normally can be done using 2 methodologies, such as: static and dynamic adsorptions, and the level of adsorption is normally in between of the two methods. Static adsorption carried out at static condition or without any fluid flow through the rock. On the other hand, dynamic adsorption is performed by injecting surfactant solution in to the rock. This tests is aimed to know the adsorption level of surfactant onto the surface of the rock. The lower the adsorption is the better solution for EOR that will be more economical.
- Wettability measurement is important factor to verify the surfactant which is classified as TFSA type of surfactant. This surfactant should create wettability change from initially more oil wet to become more water referent (Sugihardjo, 2013). A preserved core was firstly measured its wettability using AMOTT method, and then aged core by this surfactant solution was also measured its wettability using contact angle method. Then, compare both of those two wettability characteristics, if there was any change to be more water wet.
- Imbibition tests are carried out using 2 methods, those are spontaneous imbibition (Sugihardjo, 2013) and forced imbibition. The first method

is basically to measure the capability of wetting characteristic to imbibe the wetting phase into the core that was previously filled with non wetting phase without any additional forces. Then the oil volume displaced by water is recorded.

The second method is performed by additional force into the core and then the accumulation oil coming out from the core is recorded. At first, the samples were saturated with 100% formation brine, then oil was injected into the sample until no more displaced brine was recorded. After that Surfactant TFSA 0.1% was used to displace oil, the selected saturating pressure levels were applied in steps up to the maximum level of 2000 psi. The pressure is maintained until equilibrium is reached and the flow of the oil has ceased. The pressure and the change in saturation is recorded and then the pressure is changed in order to determine the next equilibrium point. Results of the complete capillary pressure curve test are tabulated and also shown graphically.

- Relative permeability is compared between relative permeability of oil-water and oil-surfactant. The measurement of relative permeability is very standard using imbibition displacement processes.
- Core flooding is the key parameter to quantify the recovery of oil, and also to verify the suitability of the chemicals for EOR application. In this experiment, some polymer is added to TFSA solution to increase the viscosity of the displacement fluid. Then it is followed by polymer solution only. Aspects related to polymer are not explained in detail in this paper. The procedure of core flooding is as follows:
  - Firstly, the core is set up at the initial reservoir condition with Soi and Swi containing the pore volume.
  - Then water flood is initiated to create Sor condition.
  - After that chemical is injected to improve oil recovery.

III. RESULTS AND DISCUSSIONS

A. Sample Preparation

TFSA-Surfactant sample

The TFSA surfactant have been selected among several candidate surfactants which has HLB value in the range of 13 to 15 which is very suitable for TFSA purposes. This surfactant contents 60% active surfactant. Chemical formula is RCON(AH2CH2OH)2 which is nonionic surfactant with excellent wetting characteristic. This surfactant then was diluted in formation water with several different concentrations based on EOR injection scenarios. The compatibility of TFSA-Surfactant with formation water will be described in very detail in the following paragraphs.

Rock Sample

Sample of rock has been cut from the down hole well and directly preserved to keep the original wettability condition. XRD analysis has been done to determine the composition of the rocks; the detailed results are presented at Table 1. The first rock is carbonate rock (LS) which consists of totally calcite and only trace of quartz minerals.

The injection of chemical into this kind of rock should be done carefully. Normally reaction between chemicals and the rock are very complex and caused very high adsorption. Therefore laboratory examination should be used as the strict guidance during field implementation, and monitoring schedules should be made more frequently.

The core, then, was plugged for several plugs for the laboratory tests. Firstly the basic data such as porosity and permeability were measured. Furthermore, the core plugs were used for the others tests i.e. wettability, relative permeability, forced capillary imbibition, spontaneous imbibition, and core flooding experiment. Table 2 shows the core plugs preparation and the basic data.

Table 1
X-Ray diffraction analysis results

No.	Rock Type	Illite	Chlorite	Calcite	Quartz	K-dsFel	Plagioclase
1	Limestone	-	-	100	trace	-	-

Table 2
Core-plug basic data

Core Plug No.	Depth (Feet)	Permeability (mD)	Porosity (%)	Grain Density (gr/cc)	Remarks
1	2868	44.02	33.20	2.70	Wettability measurement
2	2918	3.79	16.90	2.70	Wettability measurement
3	2868	97.56	28.32	2.70	Capillary imbibitions (surf TFSA 0.1%-oil)
4	2918	228.80	26.84	2.70	Capillary imbibitions (surf TFSA 0.1%-oil)
5	2868	44.02	33.20	2.70	Spontaneous Imbibition (Surf TFSA 0.3%-Oil)
6	2918	3.79	16.90	2.70	Spontaneous Imbibition (Surf TFSA 0.1%-Oil)
7	2851.2	50.77	28.94	2.71	Kro-Krw (oil-water)
8	2920.2	207.00	28.36	2.70	Kro-Krw (oil-TSFA 0.1%)
9	2899	115.50	28.31	2.70	Stacked core flooding
10	2925.5	248.50	28.64	2.71	Stacked core flooding
11	2945	249.10	26.58	2.70	Stacked core flooding
12	2887	277.30	33.93	2.71	Stacked core flooding
13	2885	58.80	28.15	2.70	Dynamic adsorption
14		Core Chips			Static adsorption
15		Core Slices			Wettability measurement by contact angle

Formation Water Sample

Samples of water have been taken carefully from the field and analyzed for its anion and cation content. The formation water contents approximately 17,000.00 mg/L equivalent NaCl. The detailed result of water analysis is shown at Table 3 which is classified as high salinity and high hardness.

It is important to understand the level of hardness and multivalent ions content in order to anticipate precipitations formation during solution mixing. Some chemical cannot withstand in this kind of formation water. Therefore, it is normal to use softened water where multivalent ions are taken out from the water. But for TFSA-Surfactant case, it can produce surfactant solution without any additional water treatment. This will be discussed more detail in the following paragraphs.

Oil Sample

The crude oil sample used was first analyzed for its physical and chemical characteristics. Viscosity is the important parameter to be measured allowing a proper polymer solution viscosity to be prepared to create piston like displacement. Some additional chemicals properties also have been measured. Table 4 shows the chemical properties. Wax content is very high at the level of 25.46%. In the contrary, the acid number is very low at the level of 0.085 mgKOH/g

Table 3
Result of water analysis

Constituents	meq/L	mg/L
Sodium	267.49	6,151.50
Calcium	25.45	510.1
Magnesium	5.13	62.4
Iron	0.08	2.3
Barium	0	0
Total Cations (excl. Fe)		**6,724.00**
Chloride	281.4	9,977.60
Bicarbonate	9.52	580.8
Sulphate	7.15	343.6
Carbonate	0	0
Hydroxide	0	0
Total Anions		**10,902.00**
Total Equiv. NaCl Conc.		**17,067.10**
pH		7.45

Table 4
Oil characteristics

Analysis	Result/Units	
Acid Number	0.085	mgKOH/g
Pour Point	78	^oF
Asphaltene Content	0.82	%
Resin Content	3.04	%
Wax Content	25.46	%
Viscosity	2.04	Cp at 83^oC

Table 5
Compatibility analysis of TFSA solution in injection water

Concentration	Observation Result					
	1st day	5th day	12th day	19th day	27th day	60th day
0.10% 0.20% 0.30%	Clear	Clear	Clear	Clear	Clear	Clear

as understood that this number is generally related to surfactant in situ generation during alkaline injection. Therefore, acid number level may have much more impact to the wettability alteration processes in such kind of experiment.

B. TFSA Solution Evaluation

Compatibility of Injection Water with TFSA Surfactant

TFSA solution was made for concentration variation with injection water of 0.10%, 0.20% and 0.30%. The solutions were evaluated their compatibility with the water for 60 days in room condition. Table 5 shows the compatibility analysis. They look clear for all concentrations in injection waters, and no precipitation and coagulation.

It means that TFSA surfactant is compatible with the formation water. Therefore further study could be accomplished to determine the suitability of TFSA surfactant for EOR projects.

IFT Measurement

Interfacial tensions have been measured between the oil and solution of several variation of TFSA concentration. The IFT is in the range 0.05 and 0.27 dyne/cm (see Table 6). Those numbers are the criteria for EOR with TFSA mechanisms. IF the target is to reduce IFT, the level of IFT need to be reduced to 10^{-3} dyne/cm. The range between 10^{-2} dyne/cm to 10^{-1} dyne/cm is appropriate number for EOR with TFSA mechanisms.

Phase behavior Study

In EOR processes, the middle phase emulsion normally gives the best phase behavior to create the lowest interfacial tension and it may contribute to the maximum recovery factor. But Lower phase also can be used in EOR processes as far as low interfacial tension occurs between surfactant solution and oil.

Table 6
IFT measurement of TFSA-OIL

TFSA Concentration (%)	IFT (dyne/cm)
0.10	5.43E-02
0.20	2.74E-01
0.30	1.23E-01

Table 7
Phase Behavior Results

TFSA Concentration (%)	Winsor Type Micro-emulsion
0.10	1
0.20	1
0.30	1
0.40	1
0.50	1

For TFSA we will not need a middle microemulsion, but lower phase microemultion will be enough.

Series of experiments have been done for phase behavior study. Variety concentration of TFSA between 0.10% and 0.5% were diluted in the injection water. These solutions were studied for their phase behavior mixing with the oil at the similar volume i.e., 2cc seal both ends, and then put them in the oven at reservoir temperature of 83^{o}C. All the mixtures indicate Winsor type I or water phase microemulsion. The detailed results are presented in Table 7.

Phase behavior study also have been performed to make sure that the solution did not produce precipitation or Winsor phase-2 microemulsion, both of which should be avoided in the surfactant preparation for EOR.

Table 8
Thermal Stability Test

TFSA Concentration (%)	IFT (Dyne / cm) and Observation			
	1st day	14th day	30th day	60th day
0.10%	5.431E-02	4.247E-01	4.206E-01	8.271E-02
	Transparent Brownish	Transparent Brownish	Transparent Brownish	Transparent Brownish
0.20%	2.739E-01	2.767E-01	3.532E-01	1.418E-01
	Transparent Brownish	Transparent Brownish	Transparent Brownish	Transparent Brownish
0.30%	1.453E-01	2.783E-01	2.784E-01	9.524E-02
	Transparent Brownish	Transparent Brownish	Transparent Brownish	Transparent Brownish

Thermal stability test

This test is almost similar to compatibility test, the only different is that the evaluation was done at elevated temperature such as reservoir temperature of 83^{o}C. TFSA solution with various concentration are put in the oven and the solution was investigated at interval of time until 60 days. The investigation results are presented at Table 8 shows that the solution still clear and no precipitation after 60 days at elevated temperature.

Again after putting in the oven at elevated temperature for long time, 60 days, the solution is still one phase with no precipitation and IFT still at the level 10^{-1} to 10^{-2} dyne/cm indicated that the surfactant solution can withstand without any damage at elevated temperatures for at least 60 day. This number has been considered as the resident time of the solution flowing in the reservoir between injection and production wells.

Filtration Flow test

TFSA with 0.1%, 0.2% and 0.3% concentration have been tested for filtration at 2 bars pressure and using 0.22 µm filter paper. Volume versus time was read regularly during fluid flow through the filter paper. While, chart of volume versus time was developed. Figure 1 is the filtration result showing straight line indicated no precipitation. The value of filtration ratio is around 1.01 to 1.03. These numbers passes the limit of screening criteria of Filtration Ratio (FR) of 1.2.

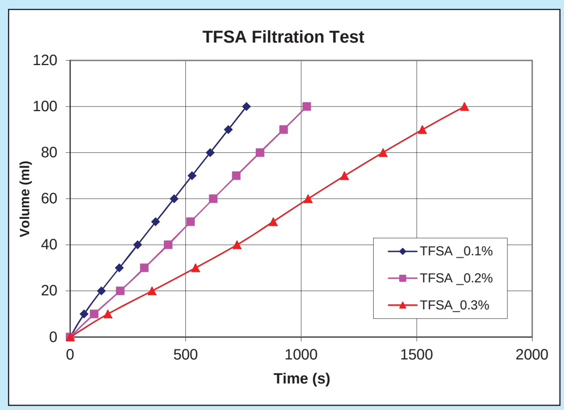

Figure 1
Filtration test results

Filtration ratio should be below 1.2 to guarantee that the solution can flow through the porous media easily without any restriction and it will not be screened in the sand face and then will reduce the quality of the surfactant solution. In turn the surfactant has no surfactant properties needed for improving displacement efficiency.

Based on the results of the surfactant solution evaluations, it is suggested that this surfactant has fulfilled the criteria for surfactant solution for EOR. Therefore further study can be accomplished for the next laboratory tests.

C. Rock-fluid interaction

Adsorption Tests

Adsorption test is also an important test to calculate how much surfactant solution will be lost in the reservoir due to adsorption onto rock surface. There are two types of adsorption test, static and dynamic adsorption. The adsorption number actually is categorized as normal. Carbonate rock basically has adsorption level higher compared to sandstone.

This adsorption level which is very important from economic point of view. Those numbers correlate to the surfactant volume will be lost into the reservoirs. The average number of the adsorption is approximately 400mgr/gr of rock. So the values in Table 9 are good numbers for EOR.

Table 9
Adsorption test

TFSA Concentration %	Adsorption Method	Adsorption μgr/gr
0.1	Static	400.07
0.3	dynamic	364.74

Wettability measurement

The original wettability of rock has been measured using preserved cores and applying AMOTT method. The results are presented in Table 10.

An Index of 0 indicates a strongly non-wetting fluid, and an index of 1.0 indicates a strongly wetting fluid. Those numbers of wettability index indicate that some part of the reservoir are more oil wet and the other part may be more water preference. This condition sometime is called mixed wet. Based on these results, injection of TFSA surfactant is recommended to change the originally mixed wet reservoir to become more water wet.

Furthermore, several core slices were also measured their wettability after aged in the TFSA surfactant solution for several days. The measurement was performed using contact angle method. The result is shown in Table 11. TFSA solution was examined for 2, 4, 8 weeks to immerse the core slices.

The wettability of the rocks was measured by dropping an oil or water bubble. The results reveal that wettability of rocks experienced a little change in wettability, the rocks tend to decrease the oil preferences with time from around 15 degrees after 2 week to around 17 degrees after 8 weeks. It is clear

Table 10
Wettabilityindex by AMOTT method

Sample No.	Depth, meter	Air Permeability mD	Porosity %	Wettability Index: Water wet index	Wettability Index: Oil wet index
1	2868.00	44.020	33.201	0.0108	0.6762
2	2918.00	3.794	16.896	0.0636	0.0000

Table 11
Wettability by Contact Angle method

No. Sample	Immersion Fluid	Immersion Time	Droplet	Contact Angle Degrees	Wettability
1	Formation Water	8 Weeks	Oil	13.20	Oil Wet
2	TFSA - 0.01%	2 Weeks	Oil	28.56	Oil Wet
3	TFSA - 0.01%	4 Weeks	Oil	37.87	Oil Wet
4	TFSA - 0.01%	8 Weeks	Oil	30.19	Oil Wet

that it need more time to change the wettability from originally oil wet to become more water wet.

Imbibition Tests

Two types of imbibition test have been conducted in this study included spontaneous imbibition and forced imbibition. The result of the first imbibitions is exhibited in Table 12 while the second imbibition is in Table 13.

Spontaneous imbibition indicates that TFSA solutions could produce oil spontaneously from the core. the recovery factor of oil by spontaneous imbibition is approximately 21.15% in high permeability reservoir while only 5.34% in low permeability. Spontaneous imbibitions is absolutely time dependent. So to produce oil quicker, forced imbibition should be introduced into the reservoir.

Forced imbibition results reveal that are very high recovery factors of oil for both in low and high permeability cores. They are more than 60%. These results is very promising to use this TFSA for EOR pilot projects.

Relative Permeability Measurement

The relative permeability was measured both for water-oil and TFSA-oil. The result can be seen in Figure 3. Both relative permeability graphs look similar and also irresidual water saturations have the same values. These phenomena can be explained that the resident time of TFSA solution was not long enough to change the wettability of the core during displacement experiment. The measurement only takes time a day or less. Therefore TFSA solution will not work properly at short resident time.

Core Flooding Experiment

Core flood was performed using 4 stacked core plugs that has been mentioned in Table 2. In this experiment need polymer solution to improve mobility ratio. Polymer products are easier to find in the market and the properties are easier to measure compared to surfactant. Therefore the properties of polymer is not explained in detail in this paper. The important parameter for polymer is viscosity that should be higher than oil viscosity. The fluid injection design is presented in Table 14. At residual oil condition after water flooding, chemical injection was initiated and the recovery factor is displayed graphically in Figure 4.

The recovery factor of oil after water flood is about 42.87% OOIP and when chemical injection begin additional oil recovery factor is around 13.50%. This result indicates that chemical injection works properly. However the level of improvement oil recovery is categorized as moderate improvement.

Table 12
Spontaneous imbibitions

Core Number	TFSA (%)	K (mD)	POR (%)	Pore Volume (cc)	Imbibition (cc)	RF (%)
5	0.1	601.40	30.92	18.44	3.90	21.15
6	0.1	62.62	20.43	11.23	0.60	5.34

Table 13
Forced imbibition

IMBIBITION OF 0.1 % TFSA SATURATION AT VARIOUS PRESSURE										
Pressure, PSI	1	5	10	42	35	50	100	500	1000	2000
Core Number	Oil Production (% OOIP)									
3	0.19	0.29	0.43	0.48	0.76	1.14	45.27	59.82	61.06	61.06
4	0.49	0.78	23.30	35.80	31.60	38.10	47.40	61.00	62.10	62.20

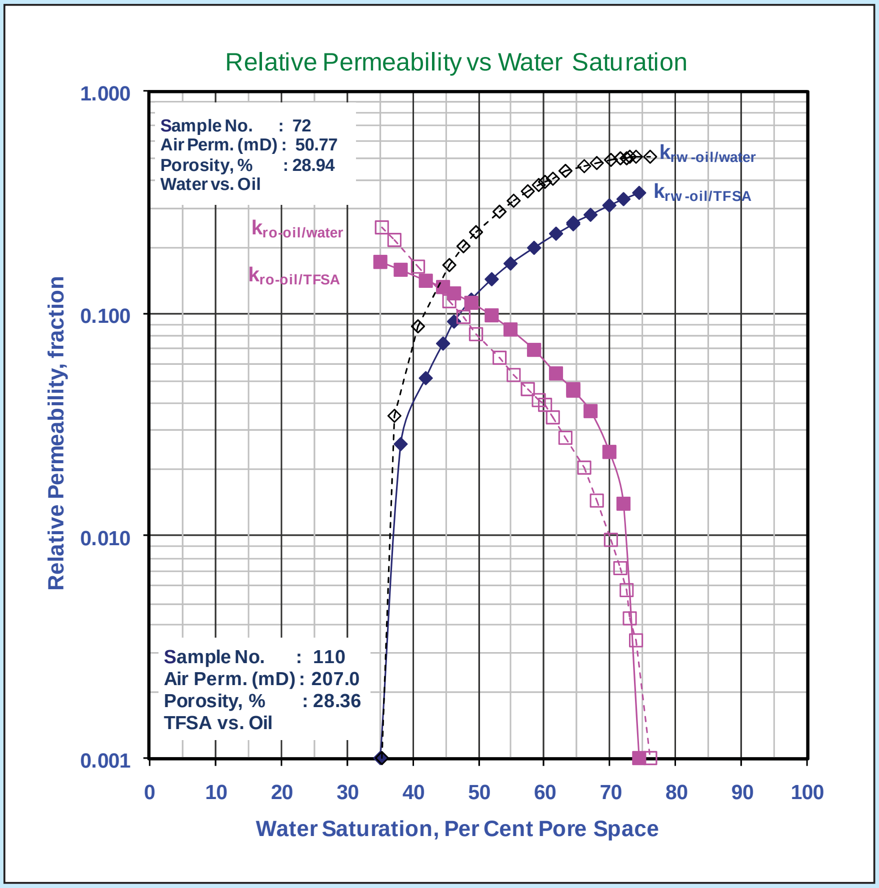

Figure 3
Relative permeability

Table14
Injection Fluid Design

Composition	Concentration	Viscosity @ 83°C	Injection Volume (PV)	pH
Main Slug				
TFSA	0.10%	6.05	0.3	8.06
Polvmer-X	0.18%			
Polymer Protective Slug				
Polymer -X	0.08%	4.46	0.2	8.42

Chance for improvement is very challenging to modify or to add some solvent or chemical in order to get a better TFSA formulation that can change the wettability effectively with shorter resident time. The recovery of oil can be expected more that 25% and that is categorized as very good.

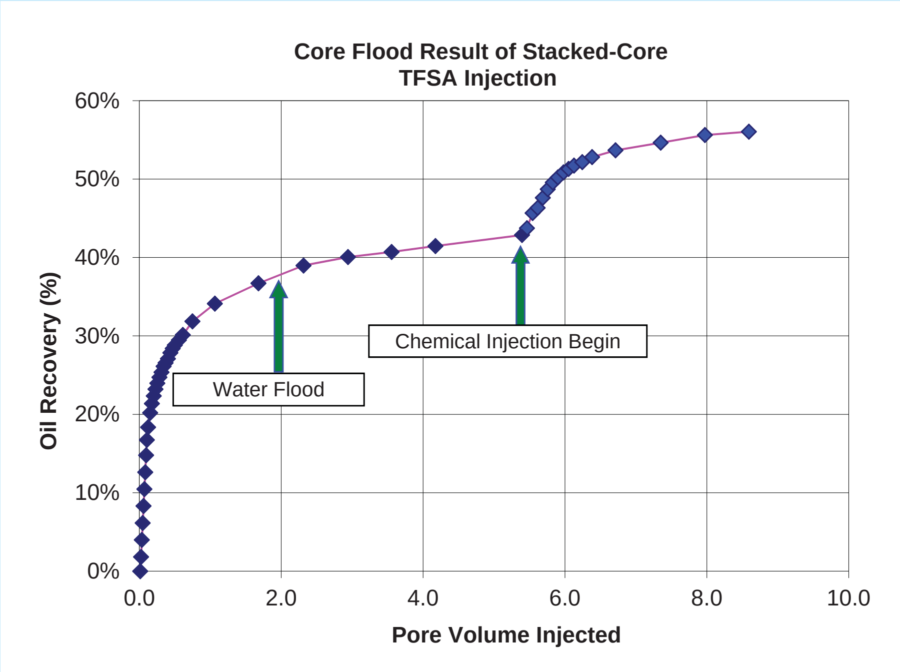

Figure 4
Recovery factor of TFSA injection

Table 15
Summary of test results

Test Parameters	Results	Category
Compatibility	Clear	excellent
IFT	10^{-1} to 10^{-2} dyne/cm	excellent
Pahse Behaviour	Winsor Type-1	Good
Thernal stability	60 days	Good
Filtration Test	1.2	excellent
Adsorption	364.74 to 400.07 µgr/gr	excellent
Wettability	Do not change	not good (need a longer resident time)
Spontaneous Imbibition	5.34 to 21.15 %OOIP	Good
Forced Imbibition	61.06 to 62.20 %OOIP	Good
Relative Permeability	Do not change	not good (need a longer resident time)
Core Flooding	13.50% OOIP	Good

The results of all laboratory tests can be summarized in Table 15 determine the test parameters, results, and the category of the results. Some test parameters indicate that they do not category as good or excellent such as wettability and relative permeability tests. They look that those tests need a longer resident time. But at the end, all tested parameters have been combined their contribution for improving oil recovery in the core flooding test. The result of core flooding is considered as good.

Coconut Ethanolamide with a HLB value around 13 to 15 normally has significant wetting/spreading properties that is very suitable for TFSA and change the wettability characteristic of rocks. Based on the equation of capillary number: $Nc = \frac{\mu V}{\sigma \cos \theta}$, the value of should approach 90 degree to get the value of cos approaches zero and the value of Nc approaches infinity, so that Sor will approach zero too.

It means that the wettability should be in between water and oil. So the design of the wettability change must be developed carefully in order to arrange the wettability to be close to 90 degree. Wettability change to totally water preference is beyond the appropriate target. Added some chemicals with proper volume is very important to create wettability close to 90 degree. Interaction of fluid and rock by considering positive and negative ion charges is also important to be considered.

Chance for improvement is still widely open and very challenging to modify or to add some solvent or chemicals in order to get a better TFSA formulation that can change the wettability effectively with shorter resident time. At the end this new formulation can improve significantly the oil recovery of old oil fields.

IV. CONCLUSION

Preparation of core, oil, formation water, and chemical has been done properly with the basic parameters which have been measured according the requirement for EOR implementation. TFSA solution evaluation includes: compatibility, thermal stability, phase behavior, and filtration test fulfills the objective of the study to prepare chemical for EOR. Rock fluid interaction evaluation such as: adsorption, wettability, imbibitions, relative permeability, and core flood experiments has been done to find quantitative numbers that can be used as the basic considerations for decision makers to implement EOR as a pilot project. All parameters could be classified as good and excellent except the wettability and relative permeability tests classified as not good. But, all tested parameters have been combined their contribution for improving oil recovery in the core flooding test. The result of core flooding is considered as good.

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