PEPTIDE SURFACTANT FOR EOR APPLICATION

SURFAKTAN PEPTIDA UNTUK APLIKASI EOR

Usman

"LEMIGAS" R & D Centre for Oil and Gas Technology
Jl. Ciledug Raya, Kav. 109, Cipulir, Kebayoran Lama, P.O. Box 1089/JKT, Jakarta Selatan 12230 INDONESIA
Tromol Pos: 6022/KBYB-Jakarta 12120, Telephone: 62-21-7394422, Faxsimile: 62-21-7246150
E-mail: upasarai@lemigas.esdm.go.id

ABSTRAK

Terdorong oleh temuan terbaru mengenai surfaktan peptida yang mampu membentuk stabil emulsi melalui penurunan tegangan antar muka, maka pengujian untuk investigasi lanjut terhadap penerapan molekul peptida untuk aplikasi EOR telah dilakukan. Surfaktan peptida yang didesain menggunakan pendekatan bioteknologi protein telah diuji skala laboratorium pada tiga karakteristik minyak, air formasi, dan batuan reservoar yang berbeda. Kinerja terbaik surfaktan peptida diperoleh pada uji menggunakan sampel A. Surfaktan peptida mampu membentuk mikroemulsi Tipe III pada pH 11. Mampu menurunkan nilai tegangan antar muka hingga kisaran 10^{-2} dyne/cm pada temperatur 25°C, walaupun masih belum memenuhi target yang diharapkan yaitu dapat menurunkan tegangan antar muka hingga 10^{-3} dyne/cm atau lebih kecil. Surfaktan peptida juga mampu mengubah sifat kebasahan batuan dari water wet menjadi strong water wet. Sampel A memiliki rantai hidrokarbon relatif pendek dibandingkan sampel B dan C, tergolong minyak intermediate, salinitas air formasi dikategorikan sedang, dan mineral batuan dominan kuarsa tanpa mineral gypsum yang sangat merusak fungsi surfaktan. Surfaktan peptida yang telah dikembangkan belum stabil pada temperatur tinggi. Uji pada temperatur 70°C menunjukkan nilai tegangan antar muka naik menjadi sekitar 10^{-1} dyne/cm. Efisiensi pendesakan menggunakan sampel minyak A kurang dari 1%. Berdasarkan pada hasil ini, maka perancangan surfaktan peptida berikutnya akan fokus pada peningkatan sifat ketahanan terhadap suhu dan rekayasa posisi susunan asam amino peptida untuk menghasilkan sifat surfaktan yang lebih baik. Hasil uji kinerja surfaktan peptida yang disajikan dalam makalah ini sangat berguna dalam perancangan surfaktan peptida yang spesifik untuk suatu lapangan minyak tertentu.

Kata Kunci: *surfaktan peptida, EOR, kelakuan fase, tegangan antar muka, kebasahan batuan*

ABSTRACT

Motivated by recent advances on the peptides surfactants that capable of forming emulsion stabilization by lowering the interfacial tension, an extensive set of tests were carried out to further investigate the applicability of peptide molecules for enhanced oil recovery application. A designed peptide surfactant using protein biotechnology approach was laboratory tested at three samples representing the different oil characteristics, water formation, and reservoir rock. The best performance of peptide surfactant obtained is of sample A. Peptide surfactant is able to form microemulsion Type III at pH 11. It can lower the interfacial tension value until the range of 10^{-2} dyne/cm at 25°C, even though itsn't reached the desired target yet which is 10^{-3} dyne/cm or even less. It can also change rock wettability from water wet into strong water wet. Sample A has relatively short hydrocarbon chain compared to samples B and C, it is classified as intermediate oil, medium salinity for water formation, and rock mineral is dominated with quartz without gypsum that is very harmful to the fuction of surfactant. The developed peptide surfactant hasn't been stable at high temperature yet. When tested at 70°C, the interfacial tension value increase to around 10^{-1} dyne/cm. Displacement efficiency using oil sample A is less than 1%. Based on these results, the next peptide surfactant design will be focused on resistance capability improvement to temperature and peptide amino acid structure position to produce the better result of surfactant. The performance test results of peptide surfactant presented in this paper is valuable in designing specific peptide surfactant for certain oil field.

Keywords: peptide surfactant, EOR, phase behavior, interfacial tension, rock wettability

I. INTRODUCTION

Enhanced Oil Recovery (EOR) technology has been proven to be able to improve oil recovery substantially from produced fields by improving microscopic and macroscopic displacement efficiencies in reservoir (Moreno et al. 2014). The obtained oil recovery addition varied. Thermal injection recovery can be more than 50% (Lumbantobing et al. 2011). CO_2 injection can reach 20% (Usman *et al.*, 2014). Chemical injection varied up to 23% (Al-Saadi et al. 2014, Zhu et al. 2014).

Based on report of 2014 Indonesia's oil and gas reserves (Jayeng, 2014), around 61% from original oil in place (OOIP) is still remaining in reservoir after primary and secondary recoveries. This percentage is equal to 45 billion barrel of oil. If some of this amount can be produced, the national oil production will increase significantly. The early research shown that chemical injection is very potential to be implemented at tertiary recovery phase to unlock that remaining oil reserves (Usman et al. 2011).

One of the most used chemical material in EOR application is surfactant. Surfactant has been proven potential to mobilize residual oil that remaining in reservoir to be flowed to production wells. Surfactant is used to lower interfacial tension (IFT) water-oil through adsorption by breaking the hydrogen chains at molecule surface. The greater surfactant adsorption causes less IFT. For surfactant injection success, IFT must be lowered from 10 to 30 dyne/cm at typical of water injection become less than 10^{-3} dyne/cm (Hirasaki et al. 2011). The very low IFT number will lower capillary pressure in rock pore that causes the improvement of displacement efficiency oil to production well. Surfactant can also be adsorbed at solid-liquid phase border that causes its contact angle. This condition will change rock wettability from oil-wet to water-wet so the oil in reservoir will be easier to flow to production wells (Wang and Mohanty, 2014).

The conventional surfactant which is mostly produced from petroleum sulfonates as result of petrochemical synthesis (Gao and Mani, 2012, Zhang et al. 2013, Zhang et al. 2015), is an organic compound that has structure composition of one or more nonpolar tail as hydrophobic which is connected to head part of polar as hydrophilic. The tail usually consists of straight or branched chain, hydrocarbon or flourocarbon with 8-18 carbon atom. The head section can be formed as nonionic, ionic, or zwitterionic. The interaction between head and water molecule through dipole or ion-dipole interaction. Basicly, the characteristics of surfactant are the manifestation of ratio between hydrophobic and hydrophilic which is known as HLB (Gadhave, 2014). The lower HLB number tends to be more soluble in oil and forms water in oil emulsion.

Unlike conventional surfactant, peptide surfactant has polyamide backbone structure with hydrophobic and hydrophilic chains decoration along its side (Dexter and Middleberg, 2008). Characteristic and ionic strength can be controlled by choosing the proper amino acids as head (Wang et al. 2011). Peptide structure can expand in a such way through regular hydrogen tie reformation of polymide backbone. Peptide that is formed by 20 kind of amino acids has surfactant characteristic separating hydrophobic amino acid in section (valine, leucine, etc.) and hydrophilic amino acid (histidine, threonine, etc.). In other word, peptide can be engineered of having amphiphilic characteristic – the separation of hydrophobic and hydrophilic – by setting amino acid composition, which is the main surfactant specification. The most two popular types of secondary peptide sturctures are α-helix and β-sheet. The α -helix structure is formed if hydrogen backbone of amide group is bonding each other and arranged spirally, whereas β-sheet structure is formed almost fully lied where adjacent backbone spread the hydrogen tie inside or between molecule. Structure type of peptide molecules will effect the IFT number (Jaya et al. 2011).

Peptide surfactant design using protein biotechnology approach was done through the following process (Jaya et al. 2012): 1) designing of amino acid sequence helix structure, 2) designing of amino acid sequence hydrophobic structure, 3) designing of amino acid sequence hydrophilic structure with negative ion content, 4) sequence simulation of design result with several parameters of reservoir condition simulation, and 5) chemical synthesis of design result and validation of helicity characteristic with circular dichroism spectroscopy. Chemical synthesis is carried out using solid phase peptide synthesis while high pressure liquid chromatography is used for purifying. The results of their work are two sequences of designed peptide surfactant amino acid, which called SUPEL with helicity characteristic and temperature stability are better than AM1 and AFD4, the first published peptide surfactant products (Dexter et al. 2006).

Motivated by recent advances on the peptides surfactants that capable of forming emulsion

stabilization by lowering the IFT (Jaya et al. 2011 and Dexter et al. 2006), an extensive set of tests were carried out to further investigate the applicability of peptide molecules for EOR applications. A number of studies show that the conventional surfactant performance is very influenced by hydrocarbon structure (Barnes et al. 2012). So, each oil field needs a specific surfactant. The purpose of this study is to evaluate the SUPEL performance at laboratory scale for various oil characteristics, water formations, and reservoir rocks for EOR application. The performance tests consist of forming microemulsion ability, lowering IFT, changing rock wettability, and improving displacement efficiency at core scale. Evaluation results describe the effect of hydrocarbon structure, water formation composition, and rock mineral content to SUPEL performance. This information is very useful in designing the specific peptide surfactant for a certain oil field.

II. METHODOLOGY

The study consists of two phases. First, the characterization of oil, water formation, and reservoir rock from three different oil fields. Second, SUPEL performance tests for EOR application at laboratory scale using those field samples.

Crude oil analysis is conducted to find out the oil characteristics which consists of API density, viscosity, asphaltene and wax contents, total acid number, and oil classification. Composition test is purposed to know the structure and distribution of light and heavy hydrocarbon component that will influence the peptide surfactant performance. The API, density, viscosity, and total acid number (TAN) are obtained using ASTM's petroleum standard test methods. The asphaltene and wax contents which representing the weight fraction of crude oil are determined using IP 243 and IFP alcohol-ether methods, respectively. Oil composition is analyzed by gas chromatography (GC) according to ASTM method.

Water formation is analyzed to determine ion composition and salinity or total dissolved solids (TDS) in water formation. Cation and anion are measured with titration which refer to API RP 45 (American Petroleum Institute Recommended Practice) method and procedure. Bicarbonate (HCO_3) and carbonate (CO_3) are calculated based on the needed acid volume to reduce pH into 8.3 for CO_3 and 4.5 for HCO_3. Sulfate (SO_4) is calculated by adding barium chloride volume and then calculating

solution turbidity. Salinity is addition of all positive and negative ion in milligram per liter (mg/L). The lowering of oil-water interfacial tension is strongly affected by salinity. At optimum salinity, surfactant can lower the IFT at the lowest point.

Reservoir rock characterization aimed to find out the rock mineral content. This is carried out using X-ray diffraction. Mineral type will affect rock wettability, that is the tendency of rock saturated by oil or water (Abassi et al. 2011). The reservoir rock with water-wet condition will flow the oil easier compared to the oil-wet one. At water-wet, oil form layer at rock surface. When contacted with water, rock will adsorb water as substituting oil to the smallest pore, so the oil is easier to flow. In contrast with oil-wet condition, oil act as water at water-wet system.

The SUPEL ability to form microemulsion is tested with phase behavior using glass tube pipette. Phase behavior describes oil solubility in surfactant. The ilustration of oil-water microemulsion phase behavior is shown at Figure 1. The expected condition to be reached is the formation of three phase, oil, water, and microemulsion or middle phase. Two mililiter of dead oil that has been filtered with 10μm filter paper is put into glass tube pipette which contains surfactant in certain concentration. The glass tube pipettes where the upper part has been closed are then put in rack at ambient temperature and 70°C. The phase behavior observation is done after fluid interface level reach the equilibrium. 100 μM SUPEL concentration is soluted into water formation with real pH and pH 11.

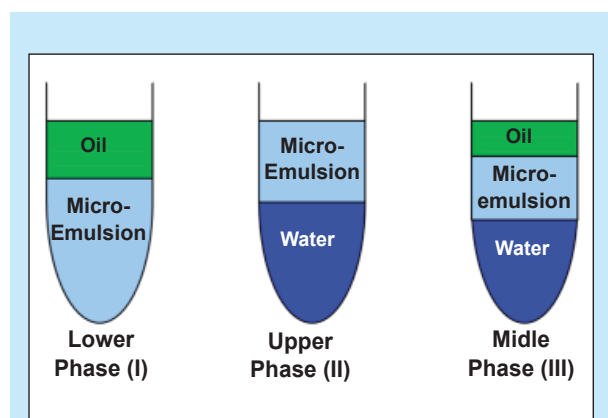The SUPEL ability of lowering oil-water IFT is measured with spinning drop tensiometer TX500C-

Figure 1
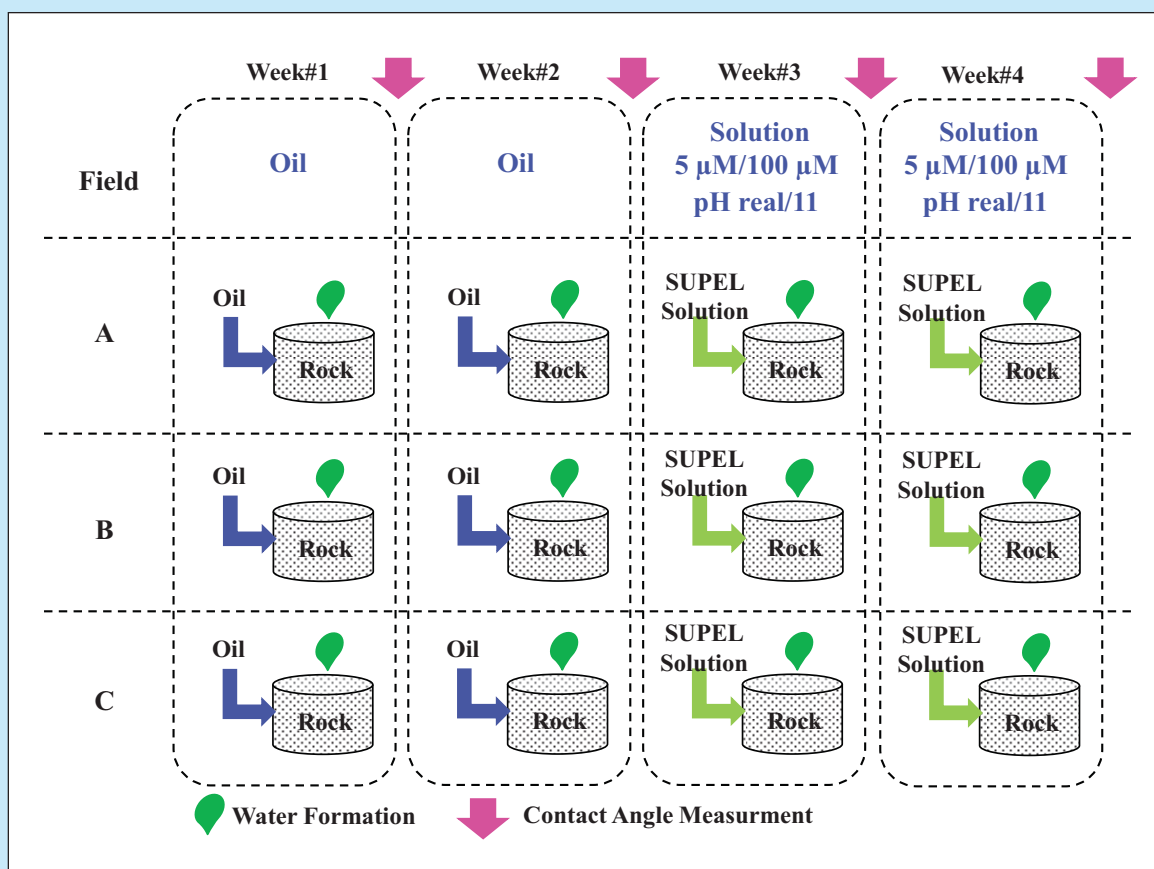**Generalized phase behavior**
for oil-watermicro emulsion.

Figure 2
Illustration of conditions for contact angle measurement.

D. The test is done for three oil and water formation samples without addition of SUPEL and with addition 25 µM of SUPEL concentration varied with real pH and pH 11 at 25°C. Real pH of water formation in oil fields A, B and C are 8.52, 8.78 and 7.98, respectively.

Rock wettability is determined through measurement of fluid contact angle with rock surface. The test is done at 70°C for those three samples representing oil, water formation, and rock. Contact angle of two types of liquid is measured with referring to phase that has greater density. The contact angle of 0 - 90° tends to water-wet. A contact angel approaching 0° indicates a strong water-wet system. While the contact angle of 90 – 180° tends to oil-wet and an angle approaching 180° indicates a strongly oil-wet rock. The test is done in two submersion conditions. First condition is where rock sample is submerged with oil and then dropped with water formation. Second condition is where rock sample is submerged with SUPEL solution with pH of water formation and pH 11 which then dropped

with water formation. The submersion is done in 4 weeks in order to cover the rock with the fluid. Condition of contact angle measurement is ilustrated at Figure 2.

Core flooding test is done to know the SUPEL solution effectivity in oil displacement process. Because there's no core in suitable size from those three rock samples, a core standard Bentheimer sandstone is used. Detail data core is provided at Table 1. First, core is saturated with oil, where the water saturation equal with water connate saturation (S_{wc}). The oil is then displaced with water until residual oil saturation (S_{or}), and then continued with displacement of SUPEL solution. Instrument and displacement test scheme is displayed at Figure 3.

III. RESULTS AND DISCUSSION

A. Oil Characteristics

Crude oil analysis and hydrocarbon composition results from three oil fields are presented at Table 2 and Figure 4. Vertical axis at Figure 4 is hydrocarbon

Table 1
Core data for oil displecemnet test

ID Core	Length (cm)	Diameter (cm)	Surface Area (cm^2)	*Bulk* Volume (cm^3)	Pore Volume (cm^3)	Porosity (%)	Permeability (mD)
Bentheimer Sandstone	30.300	3.765	11.138	337.472	77.928	23.092	3018.256

Table 2
Results of crude oil analysis for samples A, B, and C

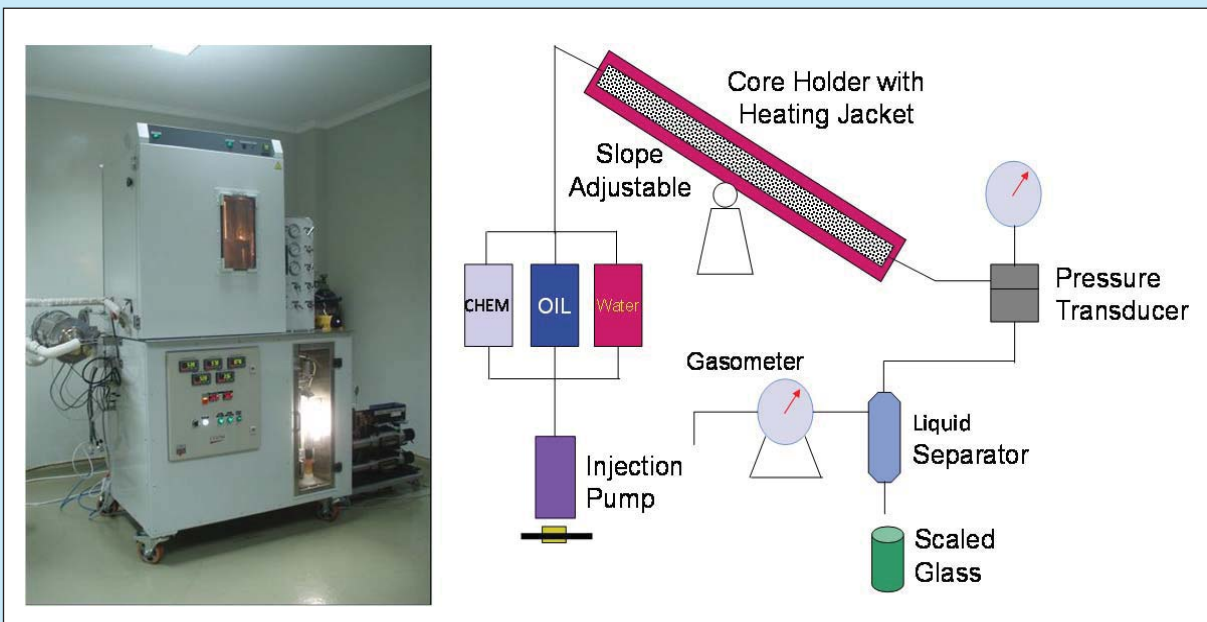| Parameter		Field		
		A	B	C
Density	g/cm^3	0.7676	0.8493	0.8692
API *Gravity* 15°C	^{o}API	44.7	29.9	29.2
Viskosity @T$_{res}$	cp	0.70	10.43	2.99
Reservoir Temperature	^{o}C	60	60	83
Pour Point	^{o}C	-24	21	27
Asphaltene Content	%wt	0.003	0.014	0.075
Wax Content	%wt	0.317	15.118	11.934
Total Acid Number	mg KOH/g	0.152	0.137	0.270
Classification		Intermediate	Parafinic	Parafinic

Figure 3
Equipment and flooding test scheme.

weight percent. Based on crude oil analysis test results, the crude oil from Field A classified as intermediate and included light oil category with API 44.7. While crude oil of Fields B and C are classified as paraffinic and included moderate oil category with API 29.9 and 29.2. These results are supported with asphaltene and wax contents of oil A that relatively low, that are 0.003 %wt and 0.317 %wt, if compared with oil B (0.014 and 15.118 %wt) and C (00.75 and 11.934 %wt).

Figure 4 shows that the greatest hydrocarbon structure at oil A is octane component (C8) which classified as light component. Whereas oil B even though octane is dominant, the other heavy components are significant. On the other hand, oil C is dominated with heavy component, that is greater than dekane $(C10^+)$ with C15 as the major component.

B. Water Formation Characteristics

The third water formation analysis results are presented at Table 3. Water formation of Field B has salinity (TDS) relatively low, that is 2205.8 mg/L compared to sample of Field A (11436.4 mg/L) and C (15963.0) which are categorized as medium salinity. The divalent ions content Ca^{2+} and Mg^{2+} that can affect clay sensitivity to deflocculating and development at water formation of Field C are quite high, that are 332.6 mg/L and 52.7 mg/L. While Ca^{2+} and Mg^{2+} of the other water formation are relatively low, that are 60.2 and 12.2 mg/L for field A and 15 and 15.2 mg/L for field B.

C. Rock Mineral Composition

The X-ray diffraction test results to the three rock samples are shown at Table 4. The table desribes that quartz content at rock of field A and B is quite high, that is 40% and 47%. Field C is dominated by carbonate, 88%. So, based on the data above, reservoir rock of Field A and B is classified into sandstone and the other one is carbonate.

Table 3
Results of formation water analysis from A, B, and C fields

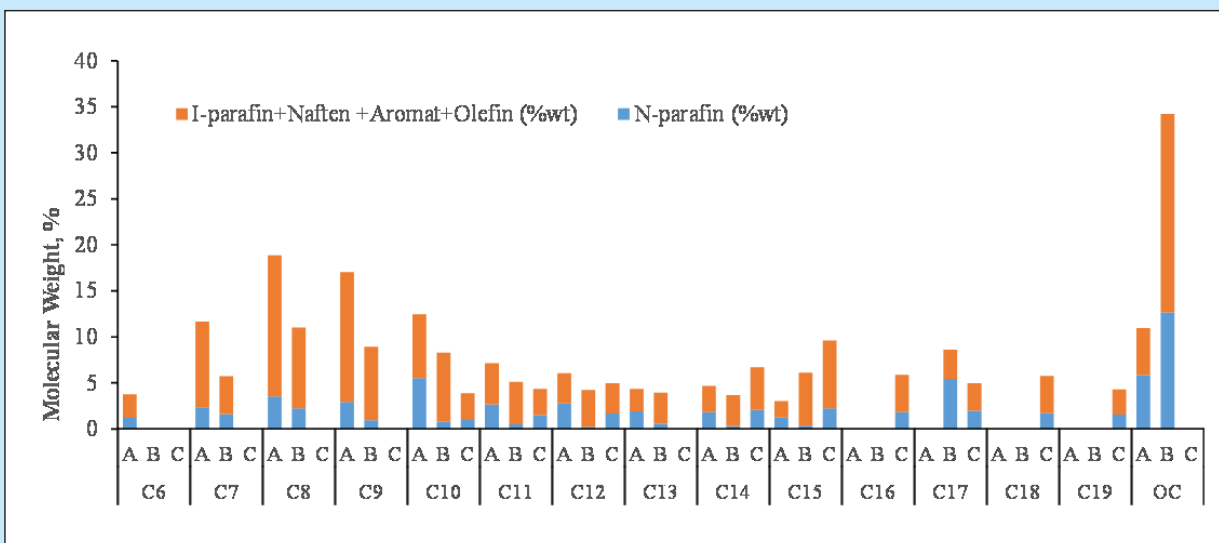| Ion	Concentration (mg/L)		
	Field A	**Field B**	**Field C**
Na^+	3990.8	699.4	4954.0
Ca^{2+}	60.2	15.0	332.6
Mg^{2+}	12.2	15.2	52.7
Fe^{3+}	0.0	0.0	0.8
HCO_3^-	418.5	829.6	410.3
SO_4^{2-}	3456.6	0.0	939.87
Cl^-	3457.1	532.5	7013.7
CO_3^{2-}	39.0	114.0	151.3
TDS	11436.4	2205.8	15963

Figure 4
Hydrocarbon composition for oil samples of A, B, and C fields.

Table 4
Results of X-Ray difraction analysis for rock samples A, B, and C

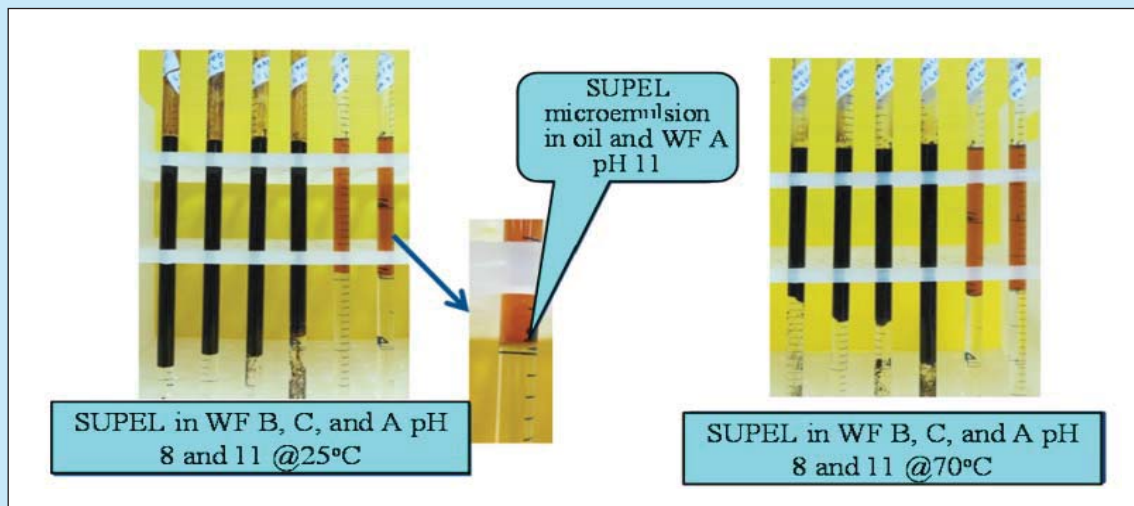| ID Sample	Clay Minerals (%)				Carbonate Minerals (%)				Other Mineral (%)					Total (%)		
	Smectite	Illite	Kaolinite	Chlorite	Calcite	Argonite	Dolomite	Siderite	Quartz	K-Feldsfar	Plagioclase	Gypsum	Pyrite	Lempung	Karbonat	Lainnya
A-PA7	22	12	18	-	-	-	-	7	40	1	-	-	-	52	7	41
B-33	-	10	10	12	10	3	3	-	47	-	3	2	-	32	16	52
C-319	-	3	3	-	88	-	-	-	4	-	-	2	-	6	88	6

Figure 5
Phase behavior of SUPEL 100 µM in oil and water formation (WF) A, B, and C fields.

Reservoir rock of Field A has a quite high clay content of 52%. Clay mineral is classified into two types, swelling and non-swelling clays. Both can affect rock formation damage. Illite and kaolonite are included as non-swelling clay, while smectite is swelling clay. At swelling clay, ionic condition change can cause swelling which at last dissolved with moving fluid. This condition results the reduction of flowing area effectively, so the permeability is reduced. Whereas, the non-swelling clay tends to release from rock surface and migrated when conductive coloid released. This particle migration can close smallest pore and cause the permeability reduction.

Gypsum is found at rock sample of Fields B and C. This mineral has relatively high solubility. The presence of gypsum above 1% can result surfactant precipitation which will relieve the fuction of surfactant itself.

D. Phase Behavior

Phase behavior test results are given in Table 5 and Figure 5. It can be seen that at 25°C and 70°C, the same tendency of phase behavior is obtained. SUPEL with 100 µM concentration at samples B and C, form upper phase (Type II) or surfactant dissolve into oil, that is surfactant salinity is greater than optimum salinity. Microemulsion (Type III) is formed at sample A pH 11.01 at 25°C. While, SUPEL at sample A pH 8.52 form bottom phase (Type I), and SUPEL at 70°C form upper phase (Type II) at pH 8.52 and pH 11.01.

Table 5
Results of phase behaviour test of SUPEL 100 μM using oils
and water formations samples from A, B, and C fields

No	Field	pH	Temp. (°C)	Water Level	Oil Level	Top Interface	Bottom Interface	Type
1	B	8.78	25	2.95	1.00	-	4.24	II
2	B	11.01	25	2.96	1.02	-	4.09	II
3	C	7.98	25	2.92	1.00	-	4.08	II
4	C	11.01	25	3.00	1.05	-	3.80	II
5	A	8.52	25	2.98	1.00	2.90	-	I
6	A	11.01	25	2.95	1.00	2.95	2.96	III
7	B	8.78	70	2.94	0.88	-	2.99	II
8	B	11.01	70	2.92	0.88	-	3.30	II
9	C	7.98	70	2.97	0.91	-	3.35	II
10	C	11.01	70	2.93	0.88	-	3.92	II
11	A	8.52	70	2.99	0.95	-	3.00	II
12	A	11.01	70	1.98	0.94	-	3.00	II

Table 6
Results of IFT test SUPEL using oil and water formation
samples from A, B, and C fields

Field	Concentratio (μM)	IFT@25°C (dyne/cm)		IFT@70°C (dyne/cm)	
		pH Real	pH 11	pH Real	pH 11
A	0	6.41×10^{-1}	$9.48 \times 10^{+0}$	$1.82 \times 10^{+0}$	5.80×10^{-1}
	25	5.30×10^{-2}	8.61×10^{-2}	3.34×10^{-1}	2.61×10^{-1}
B	0	$1.32 \times 10^{+1}$	$9.48 \times 10^{+0}$		
	25	2.98×10^{-1}	4.98×10^{-1}		
C	0	$1.06 \times 10^{+1}$	$8.35 \times 10^{+0}$		
	25	3.48×10^{-1}	1.88×10^{-1}		

Oil A characteristic and high pH environment are believed to be the factor of stimulating the forming of microemulsion type III. Oil A which has relative short carbon chain is dominated light component hydrocarbon structure, relative low asphaltene and wax contents and tends to have relative high solubility in surfactant compared to oils B and C. The presence of acid compounds in oil A as indicated by total acid number, if mixed with high pH chemical solutionn can stimulate the form of surfactant (Sheng, 2013).

F. Interfacial Tension

IFT test results are displayed at Table 6 and Figure 6. From the test results, the addition of SUPEL can decrease IFT of water-oil from range of 10 dyne/cm at condition without SUPEL addition to become 10^{-1} dyne/cm after SUPEL added at 25 μM of concentration. The best IFT decreasing happen at fluid sample Field A with pH 8.52 and pH 11.01 and at temperature 25°C that reaches 10^{-2} dyne/cm. But the surfactant function is reduced which marked by IFT increasing into 10^{-1} dyne/cm at 70°C. Whereas,

IFT number at other fluid samples only reach 10^{-1} dyne/cm. This result determines the ability of SUPEL in lowering IFT water-oil even though hasn't fulfilled the expected target, that is 10^{-3} dyne/cm or lower. As a consequence, re-optimization need to be done to the surfactant peptide.

IFT measurment results support phase behavior test results. The solution that form microemulsion type III tends to have low IFT number. The IFT decreasing is influenced by hydrocarbon structure of oil, consist of long chain hydrocarbon and branched structure hydrocarbon (Barnes et al. 2012).
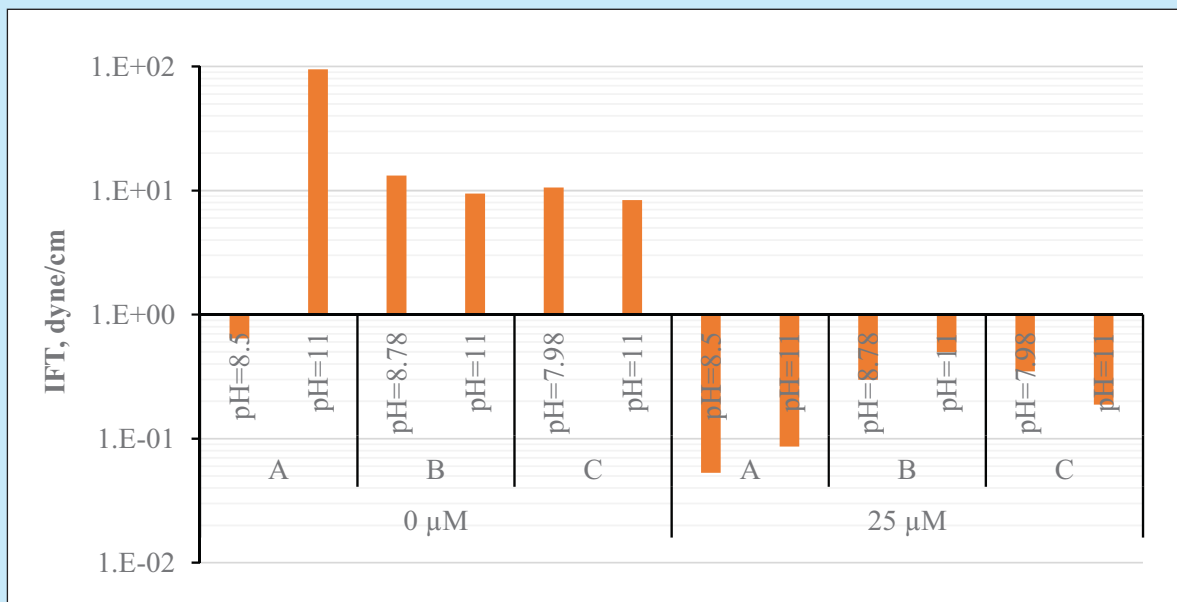

Figure 6
**Results of IFT test for SUPEL at 25oC temperature using oil
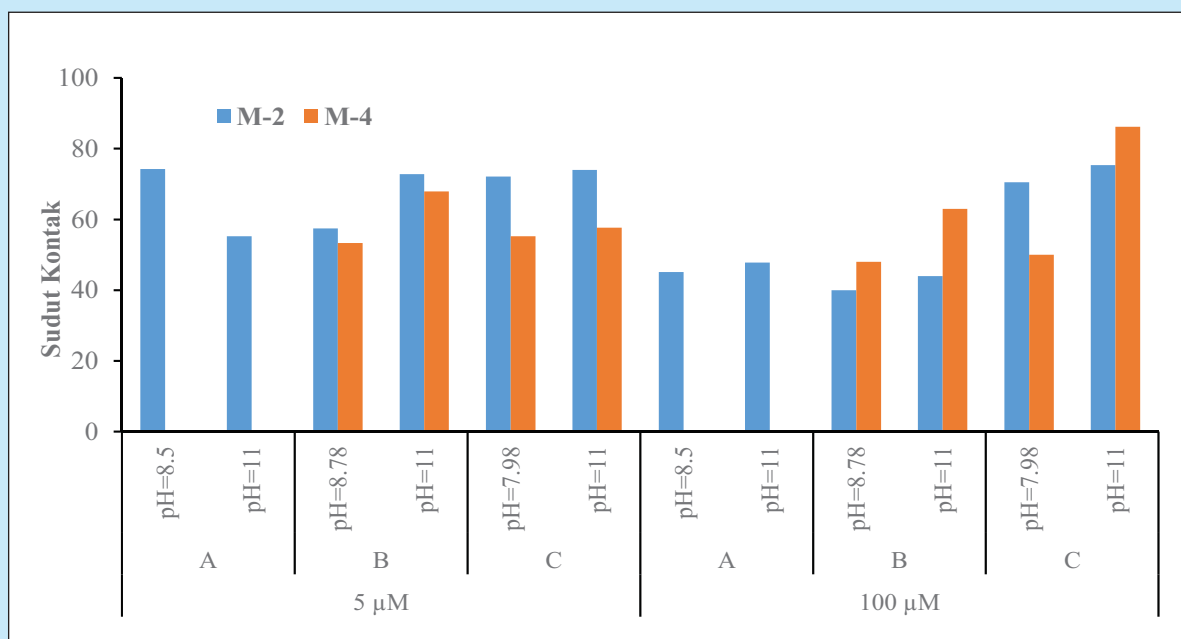and water formation from A, B, and C fields.**

Figure 7
**The change of contact angle at various submersion and SUPEL solution pH, which are tested
using oil, water formation, and rock samples from A, B, and C fields.**

Oil structure Field A is majorly in octane (C8) and branched structure of isoparaffin, naphtene, aromatic and oleofine have relative high level, 15.31 %wt, so the hydrophile tendency character is resulted.

Branched structure hydrocarbon that is dominated by isoparaffin, naphtene, aromatic and oleofine for the third samples has relatively high content, so the hydrophile tendency character is resulted. Interaction between SUPEL solution and those oils is generally forming upper phase type II microemulsion with resulting IFT in order 10^{-1} dyne/cm. This condition indicates low HLB number of SUPEL so the formation of water in oil emulsion resulted. To generate IFT in order 10^{-3} dyne/cm or lower, amino acid need to be engineered to obtain HLB equilibrium.

G. Rock Wettability

The result of contact angle measurements at oil and SUPEL solution submersions that tested to rock of Fields A, B, and C is shown at Figure 7. Generally, water-wet rock at real pH and pH 11 are for oil submersion condition. Wettability of rock A change into storng water-wet at SUPEL solution submersion with concentration of 5 and 100 µM. While at sample of rocks B and C, there is no wettability change. The change of wettability from water-wet to strong water-wet is one of oil production enhancment mechanism with surfactant injection. At strong water-wet rock, oil form layer at rock surface. When contacted with

water, rock will adsorb water replacing oil until the smallest pore, so the oil is easy to flow.

As show in Figure 7, the increasing of contact angle at high pH for oil submersion condition after two weeks (W-2), especially for rock of Fields B and C that contain calcite carbonate. High pH tends to cause calcite become unstable by Ca^{2+} activity. Submersion with SUPEL solution 5 µM after for weeks (W-4) results decreasing of contact angle at two tested pH conditions, even though not significant. The effect of SUPEL concentration addition is eliminated by the presence of gypsum in rock sample of Fields B and C.

H. Displacement Efficiency

Based on test results which have been discussed above, SUPEL shows best performance at condition of oil A. That reason determines the oil displacement test at core scale is only done using oil A sample. Figure 8 depicts enhancement of oil recovery as functioned of injected pore volume of water and SUPEL solution. SUPEL solution injection with 25 µM concentration at 70°C started after enhancement oil recovery is constant to addition of water injected pore volume. At this condition, oil saturation reaches residual saturation.

Surfactant injection at EOR phase is purposed to mobilize the residual oil. Figure 8 shows that enhancement of oil recovery from displacement process with SUPEL solution is less than 1%. This
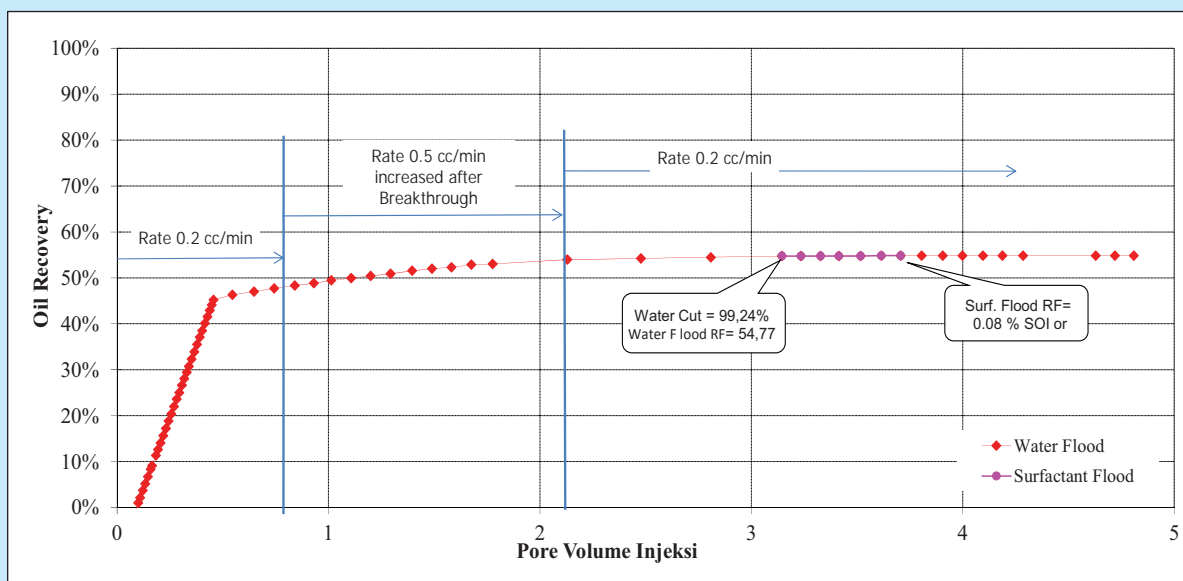

Figure 8
Efficiency of SUPEL solution injection at temperature of 70°C
in oil displacement experiment at core scale.

result in line with the IFT test results that show reducon of SUPEL function at 70°C. This condition is also shown by AM1 and AFD4 peptide surfactant products and which are first time publised that are survive only at ambient temperature and soon broke when tested at a high temperature of 70°C. So, the next SUPEL design will be focused on characteristic resistance improvement or temperature stability that allow to be used in an oil filed test.

IV. CONCLUSION

Peptide surfactant as the result of the previous research which called SUPEL has been tested at three different samples representing different oil fields. Interaction of SUPEL solution with those three fluid samples generally forms microemulsion upper phase type II by resulting IFT in order 10^{-1} dyne/cm. This condition indicates low HLB number of SUPEL that tends to form water in oil emulsion. To obtain IFT in order 10^{-3} dyne/cm or lower, re-engineered of SUPEL's amino acid need to be done in order to reach the HLB equilibrium.

The best SUPEL performance is obtained at sample A. Sample A can form microemulsion Type III. The lowest IFT is resulted at 10^{-2} dyne/cm at 25°C. This result shows SUPEL perform relatively better in oil which has relatively short of hydrocarbon chain. SUPEL is also able to change rock wettability from water-wet to strong water-wet in rock that doesn't contain gypsum.

The produced SUPEL isn't stable yet at high temperature. When tested at 70°C, IFT value increases to 10^{-1} dyne/cm. Oil displacement efficiency of sample A is less than 1%. The next SUPEL design will be focused on characteristic resistance improvement or temperature stability in order to be able used in oil field test. SUPEL performance test results at various characteristic of oils, water formations and rocks are very useful in designing specific peptide surfactant for certain oil field.

ACKNOWLEDEGMENTS

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