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Challenges in Designing the Optimum Mobility Ratio for Polymer Flooding in Reservoir with High Pour Point Oil: A Case Study from Sago Field Zone-M- Indonesia

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ABSTRACT

Sago Structure located in Pelawan District, Riau Province. Sago Structure found in 1940 and began production in August 1940. Sago Structure has active layers of the H, J, K, L layers lies in Tualang Formation and M, N, O, P layers of the Lakat Formation. Currently, the average production wells at Sago Field have an average air content of 98% - 99%, total gross fluid approximately 80,000 BFPD and net oil production between 1,100 - 1200 BOPD. Sago crude oil has the characteristics of HPPO (High Pour Point Oil) with high parrafin content (parrafin content reaches 80% of total weight).

Sago Structure will be applied polymer injection for increasing oil recovery. Polymer injection is one type of enhanced oil recovery (EOR) which is an improvement of the water injection method. It is required to decrease the mobility ratio so as to obtain better areal sweep efficiency and vertical sweep efficiency. One important step in the design of polymer injection is to determine the optimum value of mobility-ratio.

This paper will provide overview of the reservoir aspect before descriptions of mobility control determination and aspects of polymer compatibility with laboratory testing. Based on various criteria of stability of mobility (i.e. mobility ratio), the condition of mobility ratio at Field Sago Zone M indicates instability and there is potential for viscous fingering with mobility ratio value reaches 30. In order to achieve oil stability stability, the target viscosity of polymer solution is 15 cP.

Polymer compatibility tests with reservoir fluid consists of aqueous stability, rheology test by varying polymer concentration, filtration test, screen factor test, thermal stability test, and adsorption test. Polymer samples tested are polyacrylamide type FP3630S, FP5115VHM, Polyflood Max 165, Kypam 6S, Kypam 5SH. Based on the compatibility test, it was found that FP3630S 1000 ppm and Polyflood Max 165 1000 ppm can decrease mobility value and have better viscous stability against thermal and long time condition.

Keywords: Polymer, polyacrylamide, HPPO, Sago Structure

INTRODUCTION

Geographically, Sago structure is located in Pelawan regency, Riau Province, about 120 km southeast of Pekanbaru city. The structure of Sago was discovered in 1940 and began production in August 1940. The current number of drilling wells is 110 wells consisting of 45 production wells, 16 injection wells, 5 abandoned wells and 44 suspended wells (status of November 2012). The water injection started in May 1972.

Based on G&G Study in 2011, the active structure of the sago consists of layers H, J, K, L at Tualang formation and M, N, O, P at Lakat formation.

PROBLEM STATEMENT

As an illustration, production wells in Sago Field currently have an average water content of 98% - 99%, total gross fluid approximately 80,000 BFPD and net oil production between 1,100 - 1200 BOPD. Currently, all wells are produced through 2 types of artificial lifting, ie ESP and SRP.

For improving oil recovery in Sago Structure, selection of compatible polymer study is applied.

METHODOLOGY

For obtaining compatible polymer with Layer M characteristic in Sago Field and suitable for operational of polymer injection in field further, following steps have been analysis:

1. Reservoir Characterization
2. Mobility Control Design
3. Compatibility Test

1. Reservoir Characterization

1.1 Reservoir Fluid Characterization

Reservoir Fluid Characterization is purposed to get detail component data of reservoir fluid and also as base value before applied polymer.

1.1.1 Oil Characterization

Oil Characterization test is purposed to determine main component of oil content in Layer M, Sago Field. The test are including test of pour point, wax content, viscosity and oil density.

1.1.2 Brine Characterization

Brine Characterization, from production well or injection well sampling, are tested by anion-kation level determination. It is tested as consideration for polymer screening.

1.2 Rock Characterization

Parameter of porosity, permeability and relative permeability curve Layer M, Sago Field are necessary to measure parameter such as mobility.

Reservoir rock characterization has a purpose to obtain detailed data on porosity, permeability and relative permability curves as a basis step for polymer selection.

2. Mobility Control Design

Mobility ratio is one of critical parameters of the overall design in Enhanced Oil Recovery study. Mobility of a phase is defined as the ratio between effective permeability and viscosity. The general definition of stable displacement is when mobility displacing fluid is smaller (or equal to) the total mobility of the displaced fluid (multiphase). In general, mobility ratio compares the displacing fluid mobility (upstream) and displaced fluid mobility (downstream). However, the assumption of the displacement conditions of each method are different according to conditions of displacing fluid behind front. There are three displacement stability criteria that will be used as a reference for mobility control design as summarized in table 1.

3. Compatibility Test

Compatibility test of polymer are consist of:

3.1 Rheology Test in Various Concentration

Rheology test was carried out to determine value of the polymer's ability to increase water viscosity. Polymer samples were tested using a rheometer and measured at 70^{o}C.

3.2 Aqueous Stability Test

Polymer stability test in brine injection samples was carried out to determine the compatibility of the polymer with brine and observe polymer deposits. This test used polymer with a certain concentration (1000 ppm) and observed in a pipette test. The observation included solubility of polymer in brine sample without forming a separate phase so that integrity of solution in field conditions can be maintained. This test done for more than one week at room temperature and reservoir temperature using brine injected water / WIP.

3.3 Filtration Test

Filtration test has purposed to assess risk of plugging in pores by polymer molecules. The phenomenon of plugging by polymer molecules can be described by flowing the polymer through a 0.45 micron filter. Filtration ratio is obtained by recording time which is needed for polymer at a certain volume (every 20 mL) to pass the filter with differential pressure at 20 psi.

3.4 Screen Factor Test

Screen factor is value that is obtained from flow time comparison between polymer solution and brine as solvent phase. Value of screen factor describes phenomenon of a polymer passing through a pore reservoir. Screen factor tool scheme can be seen in Figure 1.

3.5 Thermal Stability Test

Thermal stability is very important parameter in selection of polymers for EOR. Thermal stability in this study was carried out by observing changes in viscosity values every week for 3 months at a reservoir temperature of 70°C. Thermal testing of each polymer candidate was carried out by Elevated Temperature Stability Evaluation which has been adjusted to the API RP 63 standard.

3.6 Adsorption Test

Adsorption method was carried out by dissolving some of polymers in a vessel of water injection field, then that solution is divided into two erlenmeyers measuring 250 mL, which respectively are referred to test solutions and control solutions. Test solution was added to berea core. The solution is then put into an oven at 70 ° C for 48 hours and measured the viscosity and density of the solution before (using control solutions) and after adsorption.

RESULT & DISCUSSION

1. Reservoir Characterization

Reservoir characteristics are very important to know in order to get a good polymer and suitable for a particular reservoir. These are consist of characteristics of oil (crude oil), formation water (brine) and rock.

1.1 Reservoir Fluids Characterization

Table 1 is illustrated result of the characterization of brine. TDS (Total Dissolve Solid) is a measure of dissolved substances (both organic and inorganic substances, such as salt, etc.) that is found in solutions. This is expressed in amount of dissolved substances with parts per million (ppm) or milligram per liter (mg/L). The TDS value of injection and production brine samples are respectively 1788 ppm and 2654 ppm, These results are classified as low salinity level (less than 3000 ppm).

Salinity is level of salt content dissolved in water. Salinity is an important characteristic for process of Enhanced Oil Recovery, especially in polymer injection method because it greatly influences the viscosity value of polymer solution. Salinity value of injection well brine is 765 ppm and production well brine is 1590 ppm. Both samples are included in low salinity and don’t have significant impact in the design of polymer solutions.

In oil characterization, tests are included determination of density, viscosity, wax content, and pour point value (Table 2). Pour point is minimum temperature where oil can flow. At temperatures below pour point, oil loses its flowing character. Pour point value is related to paraffin content of oil, where more paraffin content in oil, greater pour point is occured. The pour point value for the Sago Field crude oil sample (LS-10 well) is 42.3^{o}C, so it forms wax at room temperature.

Wax content value also describes level of paraffin in oil and affects pour point value (and also cloud point) of an oil. Higher wax content value, more paraffin contained in it. Deposition of wax or paraffin component causes loss of solubility properties of oil. This has implication for changes in temperature, pressure, and composition of crude oil due to loss of dissolved gas. Wax content value of Zona L, sample of LS-10 well, is quite large, ie 21.60%. Injection of fluid from surface with mixed temperatures (at near well bore area), which the temperature is lower, has potential for greater oil mobility problems.

1.2 Reservoir Rock Characterization

Characteristics of reservoir rock are very important things to know. Rock characterization parameter was carried out in this study is relative permeability which is needed to determine target viscosity of polymer. Relative permeability data which is used in the determination of polymer viscosity targets are shown in Figure 2.

2. Mobility Control Design

2.1 *Current Mobility Ratio* Sago Field Zona M

Mobility ratio in reservoir condition can be used to provide an overview of pressure conditions and sweeping of oil with native fluid in reservoir. Mobility ratio conditions of Sago Zona M Field have been calculated by various methods namely end-point, Gomaa, and James Sheng. same conclusions can be drawn for different criteria, namely oil pressure in Sago Field in Zone M including unstable and most likely to form channeling due to contrast in mobility between pressure fluid and oil.

In general, determination of mobility ratio using James Sheng method shows highest price where pressure becomes very unstable and considers worst conditions in reservoir. While stability criteria by using End-Point and Gomaa give same result that is range at price 3 (figure 3), which still indicates natural pressure condition of reservoir that is not good.

2.2 Polymer Viscosity Determination

Results of calculation of polymer viscosity using various methods can be seen in Figure 4. In accordance with mobility ratio of reservoir which varies for each criterion and rock type, it was obtained various polymer viscosity design. Polymer viscosity designed variously from minimum value 0.93 cP until maximum value 14.45 cP. From illustration of Figure 4, It can be concluded that James Sheng has highest stability criteria so that he produced pessimistic viscosity desain for some rock type.

3. Compatibility Test

Compatibility test of polymer are consist of:

3.1 Uji Rheologi Variasi Konsentrasi

Rheology test was carried out to determine value of polymer's ability to increase water viscosity. Polymer samples were tested using a rheometer and measured at 70^{o}C. Polymer solutions at certain concentrations have non-newtonian fluid properties because viscosity value changes with shear rate. In general, polymer solutions (which are non-newtonian fluids) are pseudoplastic which can be approximated by behavior with a Power Law model. Viscosity value that were compared between polymers were carried out at a shear rate of 7/s because it represents shear in reservoir. For viscosity values, each polymer can be seen in Figure 5.

3.2 Aqueous Stability

Stability testing of polymers in aqueous stability samples was carried out to determine compatibility of polymer with brine and phenomenon of polymer precipitation. This test is carried out by using polymer with a certain concentration (1000 ppm) and put into a pipette test. Based on observations, all polymer samples did not form sediments so that all types of polymers were compatible with Sago's brine.

3.3 Filtration

Filtration test has purposed to assess the risk of pore plugging by polymer molecules. All polymers have a filtration ratio below 1.2 (table 5).

3.4 Screen Factor

Screen factor testing was carried out on each polymer sample which was available to determine polymer's relaxation response when it passes through rock pore. Table 6 below shows value of screen factor at concentration of 1000 ppm. Screen factor value vary in range of 41.58 (Sample FP5115VHM) to highest value 84.44 (Kypam 6S). As a reference, value of solution viscosity which was measured using a rheometer and evaluated at room temperature and shear rate of 7 / s.

3.5 Thermal Stability

PolyFlood Max 165 sample showed very significant viscosity reduction until 46.8% within 7 days from original viscosity of 38.49 cP to 20.48 cP. Even so, viscosity of PolyFlood Max 165 (up to 7 days of observation) is still apropriate with minimum viscosity specification limit, which is 15 cP during 3 months of observation.

Flopaam 3630S sample is a candidate with good thermal stability. After 7 days of observation, viscosity of polymer solution decreased by only 20% from original 19.12 cP to 15.53 cP. Viscosity value is at accepted criteria of required polymer solution in 3 months observation. The test result can be seen in Figure 6.

3.6 Adsorption

Results of static adsorption tests showed that PolyFlood Max 165 polymer sample had highest adsorption value, 0.034 mg/g and Floopam 3630S polymer sample showed lowest adsorption price, 0.003 mg/g. Adsorption process had direct effect on decreasing concentration of dissolved polymer and decreasing viscosity of solution while through rock pore. Table 7 below shows that for each sample, polymer viscosity value after adsorption has decreased to almost half original value. Even though, solution viscosity of most polymer samples still meets design target except Floopam 5115 VHM which drops to 11.27 cP. This shows that consideration of effect of adsorption on performance of polymer needs to be included in determination of final design of polymer solution.

CONCLUSION & RECOMMENDATION

Conclusions & recommendation that can be made from the result of this study, i.e.:

- Waterflooding on Zone M Sago Field requires polymer additive so that viscosity of 15 cP is achieved to be able to apply maximum oil sweep efficiency by minimizing viscous fingering.
- Compatibility test has been carried out and the results showed that there are two polymer candidates that meet the criteria, i.e. SNF - Flopaam 3630S and ChemEOR - Polyflood Max 165.

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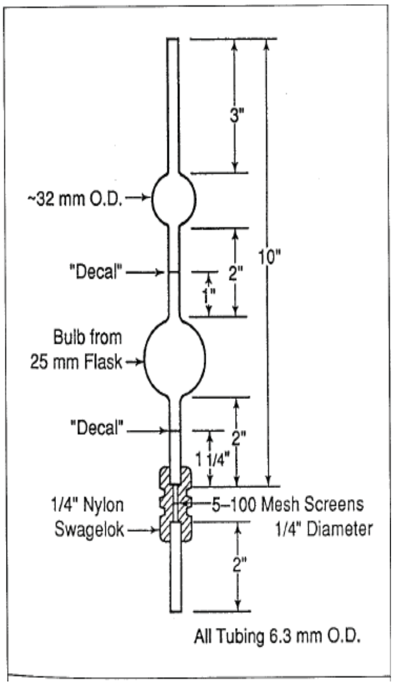

Figure 1. Scheme of Screen Factor Equipment

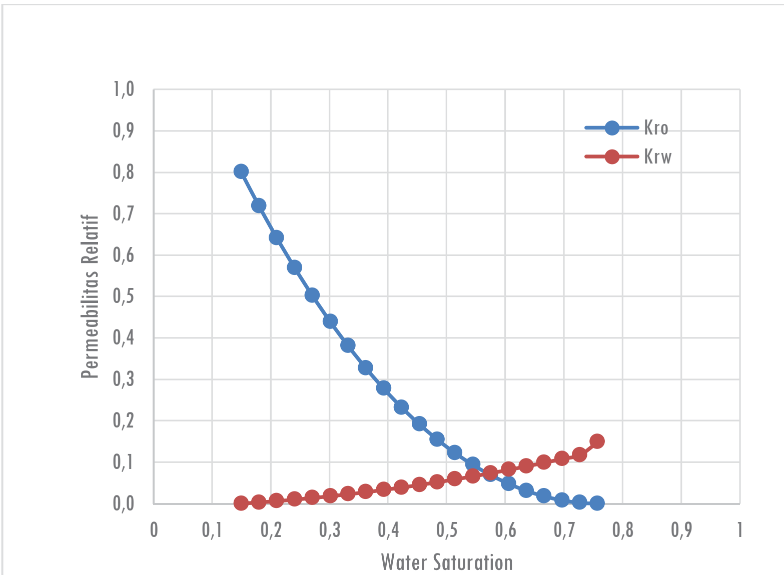

Figure 2. Relative Permeability Curve of M Zone, Sago Field

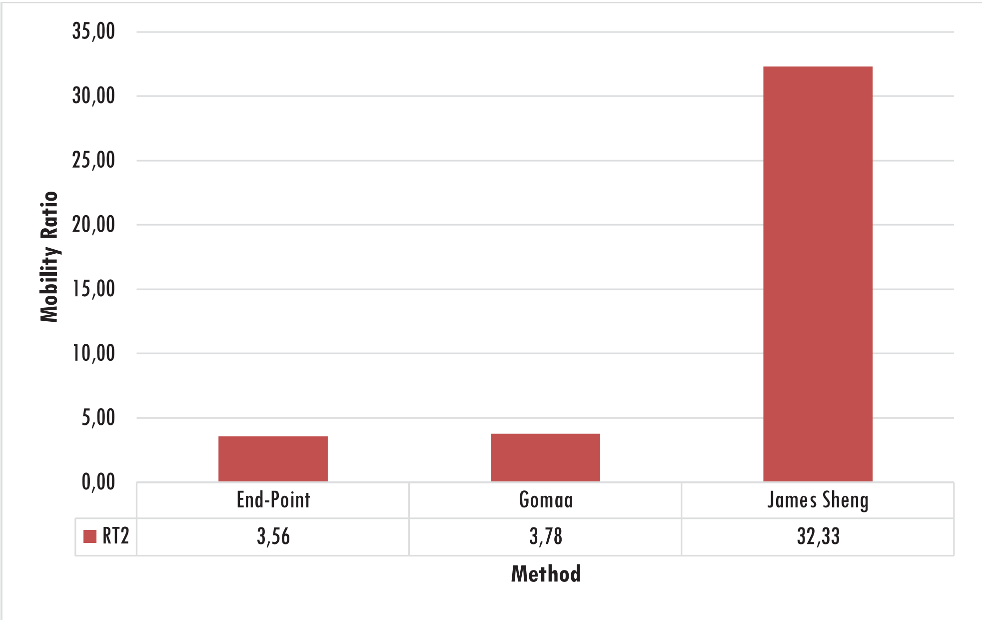

Figure 3. Current Mobility Ratio of M Zone, Sago Field

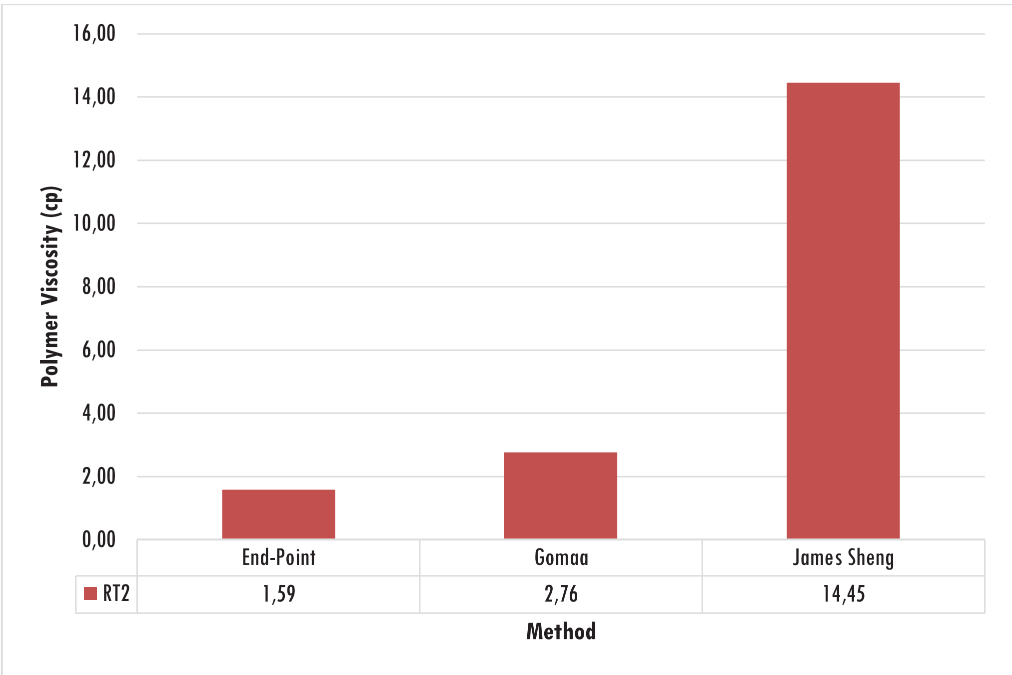

Figure 4. Target of Polymer Viscosity Design

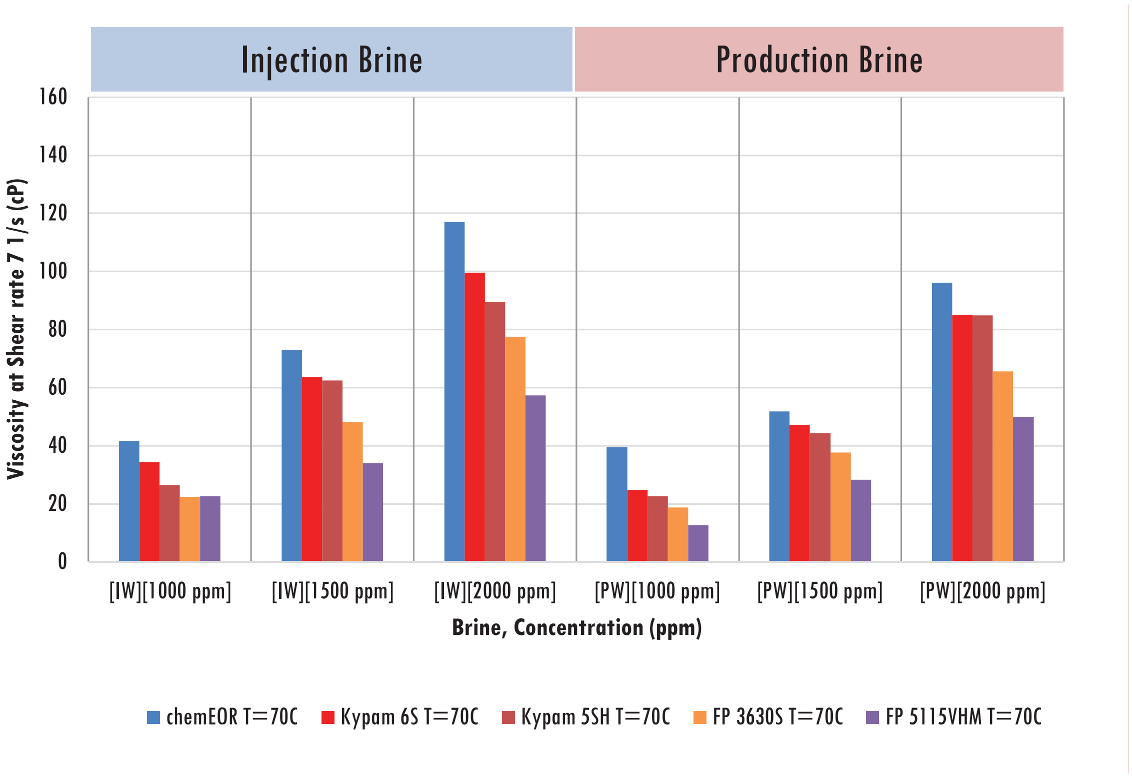

Figure 5. Viscosity (@ shear rate 7/s) vs Various Concentration of Polymer & Temperature

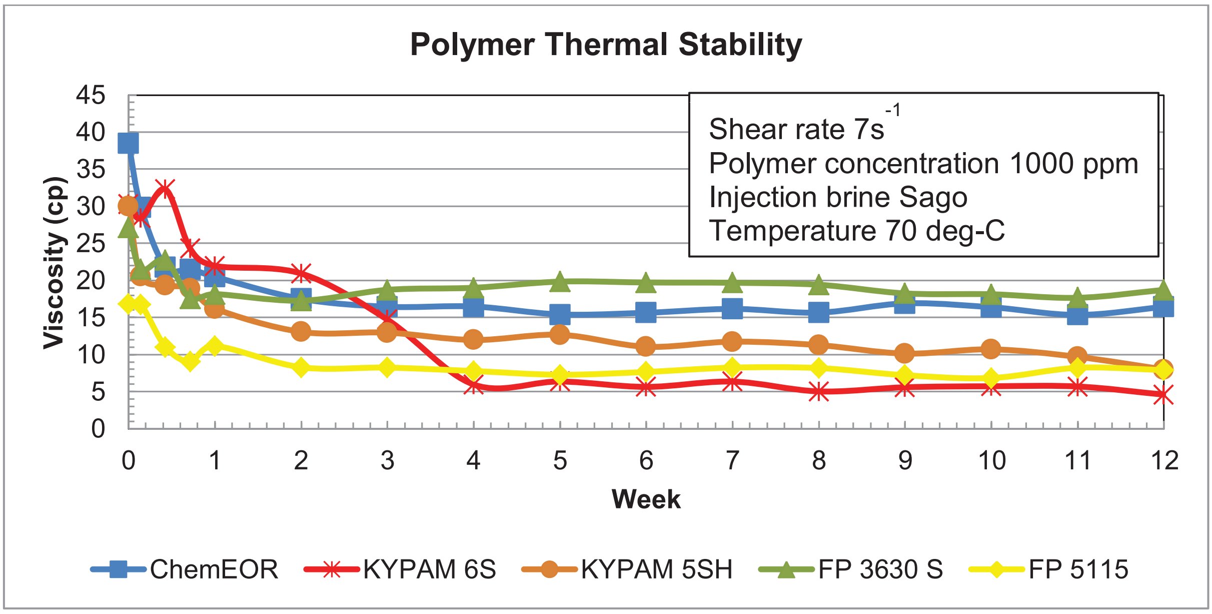

Figure 6. Observation Result of Thermal Stability Test

Table 1. Summary of Displacement Stability Criteria

No	Method	Equation	Behind Front	Ahead of Front	Remark
1	*End-Point Mobility Ratio*	$M = \frac{\left(k_{rw}/\mu_w\right)}{\left(k_{ro}/\mu_o\right)} \leq 1$	*Water mobility* (at Sor)	*Oil mobility* (at Swc)	*Oil Bank Establishment; Displacement by one phase*
2	Gomaa's	$M^{PF} = \frac{\left[(k_{rp}/\mu_p) + (k_{rw}/\mu_w)\right]^{behind}}{\left[(k_{ro}/\mu_o) + (k_w/\mu_w)\right]^{minimum}} \leq 0.35$	*Total mobility*	*Minimum of total mobility*	
3	James Sheng's	$M_{roc} \equiv \frac{k_{wr}/\mu_u \bar{S}_o}{k_{ro}(S_w)/\mu_o} \leq 1$ $\bar{S}_o = \frac{S_o - S_{wc}}{1 - S_{or} - S_{wc}}$	*Water/Polymer mobility*	*Oil Mobility*	*Displacement at oil channel*

Table 2. Sago's Water Formation Characterization

Analysis Parameters	M Zone Brine	
	WIP (injected water)	LS-10 (produced water)
TDS (ppm)	1788	2654
Salinitas (ppm)	765	1590
Densitas at T=25 C (g/ml)	1.0027	1.0033
Densitas at T=70 C (g/ml)	0.9949	0.9950
pH	8.2	8.4
Cl^- (ppm)	407	864
Ca^{2+} (ppm)	12	15
Mg^{2+} (ppm)	4.4	5
Na^+ (ppm)	874	1339
K^+ (ppm)	34	43
SO_4^{2-} (ppm)	9.1	9.6
Karbonat, CO_3^{2-} (ppm)	0	0
Bikarbonat, HCO_3^{2-} (ppm)	741	803
Ba^{2+} (ppm)	1.256	1.27
BOD (ppm)	14.3	12
COD (ppm)	11	23
Fe^{2+} (ppm)	<0.01	<0.01
Fe^{3+} (ppm)	<0.01	0.018
Viscosity, 70 C (cP)	0.4377	0.4377
Viscosity, 70 C, 539 psi (cP)	0.4469	0.4469

Table 3. Sago's Oil Characterization

Oil Characteristic	Oil LS-10 (M Zone)
Asphaltene, %	0.50
Pour point, deg-C	42.3
API Gravity	36.24
Wax Content, %	21.60
Viscosity, 70 C, dead oil, cP	12
Viscosity, 70 C, 539 psi, cP	8.568

Table 4. Polymer Compatibility Test Results

No	Polimer Sample	*Aqueous stability* (1 month)	
		Room Temperature	Reservoir Temp. (70 ^oC)
1	Polyflood Max 165	No Deposit	No Deposit
2	Kypam 6S	No Deposit	No Deposit
3	Kypam 5SH	No Deposit	No Deposit
4	Flopaam 3630S	No Deposit	No Deposit
5	Flopaam 5115VHM	No Deposit	No Deposit

Table 5. Polymer Filtration Ratio Results

No	Sample	Concentration (ppm)	FR
1	ChemEOR Max 165	1000	1.01
2	Kypam 6S	1000	1.03
3	Kypam 5SH	1000	1.03
4	Flopaam 3630S	1000	1.01
5	Flopaam 5115VHM	1000	1.09

Table 6. Polymer Screen Factor Results

No	Sample	Concentration (ppm)	*Screen Factor*	Viscosity[1]
1	Polyflood Max 165	1000	71.4	48.83
2	Kypam 6S	1000	84.44	39.76
3	Kypam 5SH	1000	63.74	32.43
4	Flopaam 3630S	1000	53.78	31.90
5	Flopaam 5115VHM	1000	41.58	30.77

Table 7. Summary of Adsorption Test Result

No	Sample	Viscosity (cP)		Amount of Adsorbed (ppm)	Adsorption (mg/g)
		Before Adsorption	After Adsorption		
1	ChemEOR Max 165	37.103	19.067	33.87661	0.034
2	Kypam 6S	34.103	17.172	18.82176	0.019
3	Kypam 5SH	33.58	15.166	6.143261	0.006
4	Flopaam 3630S	28.475	20.642	3.263708	0.003
5	Flopaam 5115VHM	22.059	11.273	12.25603	0.012