Petroleum and Coal

Article **Open Access**

Evaluation of Locally Sourced Surfactants for Enhanced Oil Recovery in the Niger Delta: An Experimental Approach

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Received June 13, 2021; Accepted December 1, 2021

Abstract

Surfactant polymer flooding is a chemical process that aims at increasing oil recovery at the end of conventional water flooding. Residual oil saturation (ROS) is reduced when this process is carefully implemented. The reduction of interfacial tension (IFT) which results from the injection of surfactant into the reservoir encourages the formation of micro-emulsion which allows more oil to be mobilized from the pore spaces and displaced to the wellbore. Polymer, when added helps to improve the mobility ratio between the in-situ fluid and injected fluid. In this study, a comparative analysis was made between Synthetic Imported Surfactant (SIS) and Locally Produced Surfactant (LPS). Xanthan gum was added in order to augment the oil recovery. Sodium Lauryl Sulphate (SLS) and Alkyl Benzoate (ABS) are the SIS while the LPS are the sample #1, #2, #3 and #4 produced from extract of palm bunch ash, ripped plantain ash, unripped plantain ash and Potash (Akanwu) respectively. The core flooding was conducted using two different displacement processes. First was injection of surfactant and polymer separately (slug injection), while in the second phase, the two fluids were mixed and injected (mixture injected). After water flooding, about 0.5 to 0.6 pore volume of the chemical formulations were injected in all the cores with three different surfactant and polymer concentrations; 0.3wt% conc. and 500ppm, 1.0wt% and 500ppm and 1.0wt% and 2000ppm. In all, slug displacement showed better recovery. At 1.0wt% surfactant and 500ppm polymer concentrations, SLS and ABS recovered maximum of 32.86% and 27.25% of oil initially in place (OIIP) respectively. 27.92%, 22.67% and 24.02% were the maximum recovered by Sample #1, #2 and #3 respectively. However, for sample #4, 27.62% maximum incremental oil recovery was obtained when 1.0wt% surfactant and 2000ppm polymer concentrations were injected. It is evident from the results presented that LPS competed strongly with the SIS.

***Keywords**: Mixture flooding; Polymer; Slug (separate) flooding; Surfactants.*

1. Introduction

Prior to completing a well, there are many challenges which must be tackled by the petroleum engineers to ensure that the well will produce optimally throughout its economic life. These challenges include but not limited to; i. determination of the extent the well can produce conventionally and ii. determination of the possible Enhanced Oil Recovery (EOR) methods that can be applied in case the conventional method ceases to be economical etc. These challenges must be tackled if the well must remain economical throughout its life time. Conventionally, when a well starts production, it is expected that the well will pass through primary recovery, secondary and finally tertiary recovery stages but however, in some cases, this sequence is not followed due to some factors resulting from abnormal fluid and rock properties. **Primary recovery** is an initial recovery process. It involves oil displacement using the energy naturally existing in the reservoir. These natural energies include water drive, gas cap drive, solution gas drive, fluid and rock expansion and gravity drainage. About 5-30% of oil initially in place is recovered by this method**. Secondary recovery** is considered when the original reservoir pressure has declined. It is initiated to enhance the pressure of the reservoir.

It involves injection of other fluids (such as water or gas) into the reservoir in order to augment the reservoir pressure. The recovery factor of this process is about 35-50% of the reservoir fluid [1]. **Tertiary or EOR method** is as usually embarked upon when the injected fluid at the secondary recovery phase seems not to effectively displace the remaining oil in place. This could be as a result as some unfavorable reservoir and fluid properties such as rock heterogeneity, capillary forces, type of rock wettability, oil viscosity and by-passed oil. Approximately 30-70% of OOIP are left in the reservoir after the secondary recovery process [2-3]. The aim of EOR processes is to extend the life of reservoirs which are approaching the economical limit under the support of water flooding, gas injection and other conventional methods. It involves the use of chemical, miscible gases and/or thermal process to mobilize and displace the residual oil after primary and secondary phases. For light oil, EOR method is usually after primary and secondary recovery mechanisms and its targets is approximately 45% of OIIP while the target of EOR for heavy oil is approximately 90% since it responds poorly to the conventional processes [4]. A broad definition of EOR has been given as "any method which is aimed at increasing ultimate oil recovery by injecting appropriate agents not normally present in the reservoir such as chemicals, solvents, oxidizers, and heat carriers in order to induce new mechanisms for displacing oil [5]. Also, it is defined as a method aimed at increasing the fluid flow by means of changing the physical properties of the reservoir rock or fluid including wettability, interfacial tension, fluid density, viscosity, permeability, porosity, pore sizes [6].

EOR methods are divided into four main groups; chemical, thermal, miscible /immiscible flooding and microbial. Of these, chemical EOR has received great attention over the years because of its simplicity and a good incremental recovery if properly done. It is a process that uses surfactants, polymer and /or alkali to increase the oil bank and as well enhance the sweep efficiency of the reservoir. Chemical EOR involves the addition of chemical to the injected water for mobility control or to lower the interfacial tensions which will in turn enhance the sweep efficiency of the portion of the reservoir contacted.

1.1 Surfactant polymer (SP) flooding

SP flooding rock wettability plays an important role in oil production. Most reservoir rocks are either oil or mixed (intermediate) wet. This however, results in poor recovery efficiency. Increase in productivity can be enhanced if the wettability of the rock surfaces is shifted greatly to water wet condition [7]. Different methods of wettability alteration have been suggested. Surfactant flooding, polymer flooding, nanoparticles stabilized emulsions, various nanoparticles-surfactant-polymer formulations and nanofluids have all been tested with varying degree of success [8-9]. Surfactant flooding is usually recommended for low to medium viscosity fluids. The aim is to reduce the IFT between the aqueous and oleous phase by lowering the capillary trapping of the rock surfaces. Numerous reports have it that surfactant flooding increases the displacement efficiency but the two major limitations are the cost of surfactant and the its low viscosity compared to oil system. However, the success of surfactant flooding is highly dependent on other complementary processes (e.g. polymer addition/injection). For improved mobility ratio and sweep efficiency, polymer is added to surfactant solution [8]. A good polymer system must be able to show good stability in challenging environments (high salinity and temperatures) which are predominant in oil reservoirs. In addition to this, it must be environmentally friendly, highly soluble, obtain greater viscosity at low concentrations and produces low IFT with oil phase. The effectiveness of polymer solution depends on its rheological properties. In another work [10], it's been reported that the viscosity of PHPAM was greatly reduced when ionic species (salts, alkali and ionic surfactants) was introduced. Chemically cross- linked nanoparticles was suggested by other authors [11] for very harsh conditions since conventional polymer systems are very susceptible resulting to severe reduction in viscosity. Also, it has been revealed that micro-emulsion flooding could be used to replace surfactant flooding since it is independent, less expensive and produces more viscous system [12]. Microemulsion is a mixture of oil, water and amphiphile (surfactant and co-surfactant) [13]. One critical factor during SP flooding is the ratio of viscous force to interfacial tension as shown in Equation (1)

$$N_{vc} = V\left(\frac{\mu_w}{\sigma_{int}}\right) \quad (1)$$

where: V = Darcy velocity; N_{vc} = capillary number; μ_w = viscosity of the displacing fluid and σ_{int} = IFT between the displaced and displacing fluid.

Capillary number is expected to be greater than 10^{-5} for efficient mobilization of the trapped oil and this is achieved if the viscosity of the displacing fluid is kept constant and the IFT is reduced [14]. The reduction in mobility ratio and IFT is affected by salinity, reservoir temperature, concentration of chemical ingredients and oil components and others; maximum oil recovery is obtained at optimum IFT and not at the lowest IFT [15]. A work has been presented on the study of the interaction between polymer and surfactant in the presence of alkali (NaOH) and salts (NaCl and $NaCO_3$) [16]. They observed that IFT of surfactant solutions increases with PAA and PHPA but decreases with Xanthan. However, the major challenges associated with Xanthan gum are its hydrolytic degradation at higher temperatures (above 70℃) and the production of cellular debris which is capable of plugging the pore throats [17].

Similarly, there is a presentation that the SP flooding is almost unfeasible when surfactant adsorption to the rock surface is too high [9, 14, 18]. A simulation of the effects of rock physical properties on the feasibility of surfactant flooding has been made. It was observed that adsorption and capillary pressure have the maximum and least impacts on efficiency of SP flooding respectively [19]. Their work also revealed that presence of salt significantly reduces the IFT between polymer and surfactant system. This was also confirmed [18]. In their works, they concluded that the adsorption of an anionic surfactant on dolomite was significantly reduced under certain conditions by preferential adsorption of sodium polyacrylate, and that silica nanoparticles could reduce adsorption when mixed with surfactant and consequently increases the oil recovery [9, 18].

In recent years, the use of local materials for chemical EOR has received greater attention. It has been noted by many authors that these local materials are particularly important because of the environmental challenges posed by synthetic products and the high cost involved. So far, there has been varying degree of success recorded in laboratory when local materials are tested for enhanced oil recovery. Results obtained showed that they competed strongly with the foreign synthetic products, and revealed that NaOH, KOH, Na_2CO_3 and palm bunch (PBA) improved oil recovery from 55% obtained by saline water flooding to 66%, 74%, 59% and 64% respectively when light and intermediate oil systems were used [1]. Additional recovery of 20% and 23% from surfactant and polymer augmented surfactant flooding has also been reported [20]. Sodium metaborate ($NaBO_2$) and ammonium hydroxide (NH_4OH) have also been investigated as alternatives for conventional alkalis [21]. Selective adsorption in dual surfactant systems has also been presented; surfactant size and shape are considered during formulation and concentration slug size considered for economic benefits [22-24].

In this study, series of SP flooding were carried out on intermediate oil system to evaluate the suitability of locally sourced surfactants over imported products for enhanced oil recovery in the Niger delta.

2. Materials and method

2.1. Materials

The crude used in the experiment was obtained from Niger Delta and the properties are shown in the Table 1. The properties and compositions of the surfactants used are also summarized in Table 2.

Table 1. Crude oil properties measured at 29°C

Properties	Value
Density (g/cm³)	0.921
API gravity (o)	24.37
Viscosity (cP)	27.15

Table 2. Local and synthetic surfactants

Local surfactant	Synthetic surfactant
1. Sample #1 (produced from palm bunch ash)	Sodium lauryl sulfate (SLS): • Chemical $C_{12}H_{25}OSO_3.Na$ • Molecular weight: 288.38 • Type of surfactant: Anionic surfactant
2. Sample #2 (produced from ripped plantain)	Akyl benzene sulfonate (ABS): • Anionic surfactant
3. Sample #3 (produced from un-ripped plantain)	
4. Sample #4 (produced from potash)	

Other materials used include; polymer (xanthan gum), brine (from NaCl), encapsulated core samples, distilled water, canon U-tube viscometer, thermometer, desiccators, top-loaded weighing machine, pycnometer (density bottle), pump, conventional oven, electronic venier caliper, stop watch, pH meter, retort stand, vacuum pump and Permeameter.

2.2. Method

2.2.1. Preparation of surfactant and polymer solutions

Complete dissolution of the polymer concentration was obtained when water heated to temperature range of 60°C to 80°C was used. 500ppm and 2000ppm polymer concentration were prepared by dissolving 0.5g and 2g of polymer in 1000ml of distilled water respectively. In preparing surfactant solution, the quantity required for the black soaps were dried for period of 72 hours and later grounded. 0.3wt% and 1wt% of each surfactant were prepared by dissolving 0.3g and 1g of it in 100mL of distilled water respectively.

2.2.2. Brine solution

Brine concentration of 10,000ppm was used. It was produced by dissolving 10g of NaCl in 1000mL of distilled water.

2.2.3. Determination dynamic and kinematic solutions

Viscometer of model 150/601B with constant 0.03641492 was used to determine the kinematic and dynamic viscosities of all the fluids used for the SP flooding and the results are presented in Table 3. The pH values of various chemical formulations used in the flooding were taken and reported in Table 4.

Kinematic viscosity (μ_k) = Effluent time × viscometer constant (2)

Dynamic viscosity (μ_d) = kinematic viscosity × density (3)

Table 3. Kinematic and Dynamic viscosities of each formulation measured at 29℃

S/N	Concentration of the fluid	Effluent time (sec)	Density (g/cm^3)	Kinematic viscosity (cP)	Dynamic viscosity (cP)
1	0.3wt % of #1	26	1.0012	0.9468	0.9479
2	500ppm of polymer	26	1.0002	0.9468	0.9470
3	Mixture of 0.3wt% of #1 + 100ml of 500ppm of polymer	26	1.0014	0.9468	0.9481
4	0.3wt% of #2	26	1.0002	0.9468	0.9470
5	Mixture of 0.3wt% of #2 + 100ml of 500ppm of polymer	26	1.0014	0.9468	0.9481
6	0.3wt % of #3	26	1.0014	0.9468	0.9481
7	Mixture of 0.3wt% of # + 100ml of 500ppm of polymer	27	1.0010	0.9832	0.9842
8	0.3wt% of #4	25	1.0004	0.9104	0.9107
9	Mixture of 0.3wt% of #4 + 100ml of 500ppm of polymer	27	1.0012	0.9832	0.9844
10	0.3wt% of SLS	28	1.0012	1.0196	1.0208

S/N	Concentration of the fluid	Effluent time (sec)	Density (g/cm^3)	Kinematic viscosity (cP)	Dynamic viscosity (cP)
11	Mixture of 0.3wt% of SLS + 100ml of 500ppm of polymer	27	1.0006	0.9832	0.9838
12	0.3wt% of ABS	27	1.0004	0.9832	0.9836
13	Mixture of 0.3wt% of ABS + 100ml of 500ppm of polymer	26	1.0002	0.9468	0.9470
14	1wt% of #1	26	1.0030	0.9468	0.9496
15	Mixture of 1wt% of #1 + 100ml of 500ppm of polymer				
16	1wt% of #2	29	1.0018	1.0560	1.0580
17	Mixture of 1wt% of #2 + 100ml of 500ppm of polymer				
18	1wt% of #3	27	1.0018	0.9832	0.9850
19	Mixture of 1wt% of #3 + 100ml of 500ppm of polymer				
20	1 wt% of #4	29	1.0022	1.0560	1.05831
21	Mixture of 1wt% of #4 + 100ml of 500ppm of polymer				
22	1 wt% of SLS	28	1.0024	1.0196	1.0221
23	Mixture of 1wt% of SLS + 100ml of 500ppm of polymer				
24	1 wt% of ABS	28	1.0016	1.0196	1.0245*
25	Mixture of 1wt% of ABS + 100ml of 500ppm of polymer				
26	2000ppm of polymer	28	1.0014	1.0196	1.0210
27	Mixture of 1wt% of #1 + 100ml of 2000ppm of polymer	27	1.0018	0.9832	0.9849
28	Mixture of 1wt% of #2 + 100ml of 2000ppm of polymer	27	1.001	0.9832	0.9842
29	Mixture of 1wt% of #3 + 100ml of 2000ppm of polymer	29	1.0022	1.0560	1.0584
30	Mixture of 1wt% of #4 + 100ml of 2000ppm of polymer	29	1.0018	1.0560	1.0579
31	Mixture of 1wt% of SLS + 100ml of 2000ppm of polymer	29	1.0018	1.0560	1.0579
32	Mixture of 1wt% of ABS + 100ml of 2000ppm of polymer	29	1.0024	1.0566	1.058

Table 4. pH values for the chemical formulations

Sample concentration	pH Value
0.3 wt% sample #1	8.95
1.0 wt% of sample #1	7.74
0.3wt% sample #2	9.64
1.0wt% sample #2	7.57
0.3wt% sample #3	8.59
1.0 wt% sample #3	10.18
0.3wt% sample #4	9.35
1.0 wt% sample #4	10.09
0.3wt% SLS	6.31
1.0wt% SLS	6.86
0.3wt% ABS	2.48
1.0wt% ABS	2.04
500ppm polymer	6.46
2000ppm polymer	9.63

2.2.4 Determination of plug permeability

Determination of plug permeability with the differential pressure measured on the Permeameter while the fluid (brine) flows across the core plug, Darcy's law for incompressible fluid equation was used to estimate permeability as shown in Table 5.

K = $\frac{Q\mu L}{A\Delta P}$ (4)

A = 2hr(h+r) (5)

where: Q = flow rate ${cm^3}/{sec}$; μ = viscosity of the brine, cP; L(h) = length of the plug (cm); A = cross sectional area of the plug (cm^3); ΔP = differential pressure (inch H_2O), 1 inch H_2O = 2.46×10^{-3} atm; r = radius of the plug, cm; K = permeability (D).

Table 5. Absolute permeability of the plug samples

Plug no	Flow rate	Brine viscosity (10000 ppm)	Actual length of the plug	Plug radius	Area of the plug	Differential pressure ($\times 10^{-2}$)	K(D)
$A1p$	37.854	0.9283	8.18	1.77	110.71	2.46	105.54
$A2p$	37.854	0.9283	6.69	1.91	106.50	2.95	77.85
$A3p$	37.854	0.9283	8.18	1.92	121.9	3.62	65.14
$A4p$	37.854	0.9283	7.90	1.84	112.66	2.91	84.67
$A5p$	37.854	0.9283	8.27	1.85	117.69	2.21	91.12
$A6p$	37.854	0.9283	7.65	1.81	107.52	2.83	88.35
$A7p$	37.854	0.9283	8.10	1.80	112.02	2.71	93.76
$A8p$	37.854	0.9283	7.78	1.93	117.80	2.53	91.73
$A9p$	37.854	0.9283	8.19	1.65	102.06	3.32	84.94
$A10p$	37.854	0.9283	8.44	1.60	100.98	3.15	93.24
$A11p$	37.854	0.9283	7.70	1.94	117.56	2.89	76.64
$A12p$	37.854	0.9283	7.26	1.95	112.89	2.19	103.19
$A13p$	37.854	0.9283	7.78	1.80	108.40	2.21	114.12
$A14p$	37.854	0.9283	8.01	1.71	104.48	2.46	109.51
$A15p$	37.854	0.9283	8.27	1.84	116.93	3.36	73.97
$A16p$	37.854	0.9283	8.16	1.59	97.45	3.18	92.53
$A17p$	37.854	0.9283	8.06	1.76	108.64	3.69	70.65
$A18p$	37.854	0.9283	7.32	1.81	103.88	2.21	112.04
$A19p$	37.854	0.9283	8.06	1.65	100.71	2.96	95.01
$A20p$	37.854	0.9283	7.07	1.74	96.36	2.15	119.91
$A21p$	37.854	0.9283	6.94	1.76	96.25	2.95	85.89
$A22p$	37.854	0.9283	7.81	1.72	103.04	2.21	120.52
$A23p$	37.854	0.9283	7.36	1.81	104.33	2.21	112.17
$A24p$	37.854	0.9283	7.06	1.67	91.64	2.37	114.22
D1p	37.854	0.9283	8.08	1.73	100.59	2.46	114.74
D2p	37.854	0.9283	7.37	1.81	104.45	2.71	91.49
D3p	37.854	0.9283	7.26	1.69	95.08	3.64	73.71
D4p	37.854	0.9283	7.56	1.71	99.64	3.20	83.32
D5p	37.854	0.9283	6.89	1.79	97.67	2.46	100.77
D6p	37.854	0.9283	7.62	1.80	106.59	2.69	93.39
D7p	37.854	0.9283	8.30	1.74	109.81	2.21	120.18
D8p	37.854	0.9283	8.11	1.72	106.28	2.31	116.08
D9p	37.854	0.9283	7.88	1.84	112.42	2.95	83.49
D10p	37.854	0.9283	8.00	1.67	101.51	2.58	107.34
D11p	37.854	0.9283	7.76	1.70	101.09	3.44	78.41
D12p	37.854	0.9283	7.74	1.89	114.41	3.12	76.19

2.2.5. Core saturation and determination of OIIP

Brine concentration of 10,000ppm was used to saturate the cores. By pumping oil through the core, the volume of water displaced by the oil represents the volume of OIIP. Initial oil (S_{oi}) and water (S_{wi}) saturations were also calculated (Table 6), and Equations (6) to (10) were applicable.

$Bulk\ Volume\ = \pi r^2 h$ (6)

P$ore\ Volume = \frac{W_{sat.plug} - W_{dryplug}}{\rho_{brine}}$ (7)

Porosity, $\emptyset = \frac{P.V}{B.V} \times 100\%$ (8)

$S_{oi} = \frac{N}{PV}$ (9)

S_{wi} = 1- S_{oi} (10)

Table 6. Initial oil and water saturation for the core plugs

Plug no	Bulk volume (cm^3)	Pore volume (cm^3)	Porosity fraction	Porosity (%)	OIIP (mL)	S_{oi} (%)	S_{wi} (%)
A_{1p}	80.55	24.45	0.3035	30.35	19.00	77.71	22.29
A_{2p}	79.80	26.81	0.3360	33.60	21.00	78.33	21.67
A_{3p}	94.78	24.01	0.2533	25.33	16.34	68.05	31.95
A_{4p}	84.06	25.92	0.3084	30.84	18.26	70.45	29.55
A_{5p}	88.96	23.08	0.2594	25.94	18.00	77.99	22.01
A_{6p}	78.77	25.26	0.3080	30.80	20.50	81.16	18.84
A_{7p}	82.48	24.61	0.2984	29.84	18.88	76.72	23.28
A_{8p}	91.08	24.93	0.2737	27.37	17.34	69.55	30.45
A_{9p}	70.08	26.61	0.3811	38.11	19.30	72.26	27.74
A_{10p}	67.91	25.82	0.3802	38.02	21.40	82.88	17.12
A_{11p}	90.08	25.71	0.2854	28.54	18.94	73.67	26.33
A_{12p}	86.77	26.68	0.3075	30.75	19.01	71.25	28.75
A_{13p}	79.23	22.56	0.2847	28.47	17.00	75.35	24.65
A_{14p}	73.62	23.04	0.3130	31.30	18.00	78.13	21.88
A_{15p}	88.00	21.84	0.2482	24.82	16.87	77.24	22.76
A_{16p}	64.84	23.46	0.3618	36.18	15.89	67.73	32.27
A_{17p}	78.47	26.87	0.3424	34.24	22.70	84.48	15.52
A_{18p}	75.41	22.88	0.3034	30.34	18.08	79.02	20.98
A_{19p}	68.67	25.59	0.3727	37.27	18.29	71.47	28.53
A_{20p}	67.28	24.74	0.3677	36.77	18.44	74.54	25.46
A_{21p}	67.57	25.99	0.3846	38.46	21.00	80.80	19.20
A_{22p}	72.62	20.06	0.2762	27.62	15.20	75.77	24.23
A_{23p}	75.78	26.84	0.3542	35.42	20.00	74.52	25.48
A_{24p}	61.88	23.73	0.3834	38.35	16.88	71.13	28.87
D_{1p}	76.01	24.12	0.3173	31.73	20.00	82.92	17.08
D_{5p}	65.17	26.67	0.4092	40.92	21.00	78.74	21.26
D_{9p}	69.08	22.98	0.3327	33.27	18.60	80.94	19.06
D_{13p}	78.98	20.84	0.2639	26.39	18.10	86.85	13.15
D_{17p}	83.85	25.72	0.3067	30.67	21.10	81.65	18.35
D_{21p}	70.49	26.05	0.3696	36.96	21.80	83.69	16.31
D_{2p}	75.89	24.94	0.3288	32.88	20.00	80.16	19.34
D_{6p}	69.48	26.56	0.3827	38.27	21.00	78.98	21.02
D_{10p}	77.60	26.87	0.3463	34.63	22.00	81.88	18.12
D_{14p}	75.41	21.98	0.2915	29.15	17.30	78.71	21.29
D_{18p}	70.12	24.92	0.3553	35.54	20.20	81.06	18.94
D_{22p}	86.90	25.96	0.2987	29.87	21.70	83.59	16.41

2.2.6 SP flooding

Two displacement mechanisms were used. First was flooding chemical formulations of surfactant and polymer separately, while in the second process, both were mixed. Six different cases were evaluated as shown in Table 7. About 0.5- 0.6 PV was injected in all cores. Figure 1 is used to show the experimental set up.

Table 7. SP formulations and flooding mechanism

Case	Concentration		Method of flooding
	Surfactant (wt%)	Polymer (ppm)	
1	0.3	500	Surfactant followed by polymer
2	0.3	500	Polymer + surfactant
3	1.0	500	Polymer followed by surfactant
4	1.0	500	Polymer +surfactant
5	1.0	2000	Polymer followed by surfactant
6	1.0	2000	Polymer +surfactant

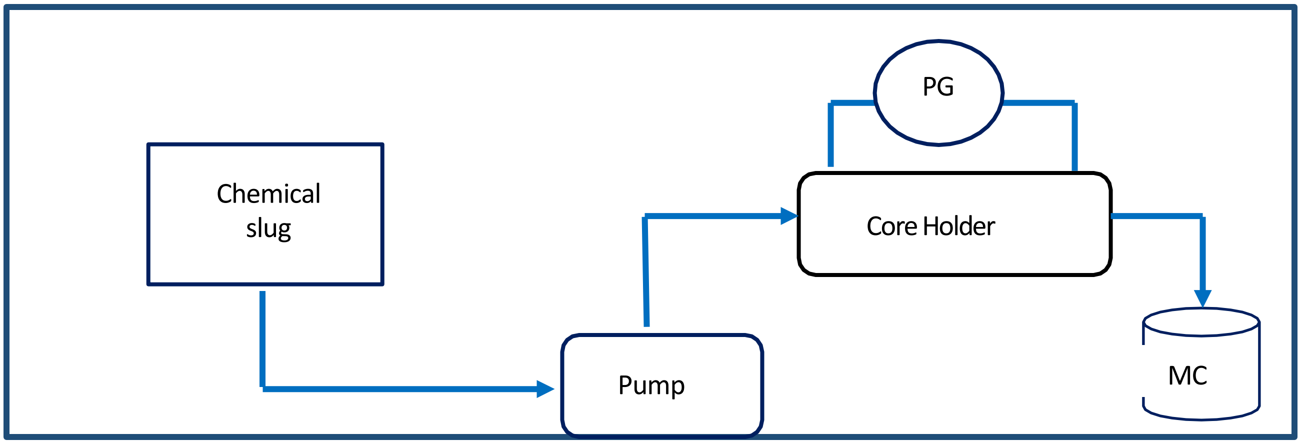

Figure 1. Experimental set up

2.2.7. Determination of incremental oil saturation after SP flooding (S_{or2}) and displacement efficiency (E_D)

The Equations (11) to (13) are presented thus;

$$E_D = \left(1 - \frac{S_{or2}}{S_{or1}}\right) \times \frac{100}{1} \tag{11}$$

$$S_{or1} = \frac{N - N_{P(wf)}}{PV} \tag{12}$$

$$S_{or2} = \frac{N - N_{P(wf+sp)}}{PV} \tag{13}$$

3. Results presentation and discussion

3.1. Results

The effect of surfactant polymer flooding on oil recovery has been studied. Two different flooding mechanisms were adopted. The first was flooding with the slug containing surfactant and polymer while the second process was injection of polymer followed by surfactant. The slug injection was initiated immediately after water flooding. 0.5 to 0.6 PV of the chemical slug was injected in all the cores used in the experiment. Initial concentrations of surfactant and polymer were 0.3%wt and 500ppm respectively. Also considered were 1.0 %wt and 500ppm and 1.0%wt and 2000ppm. The results obtained from the two mechanisms adopted are presented in the Figures 2 through 7.

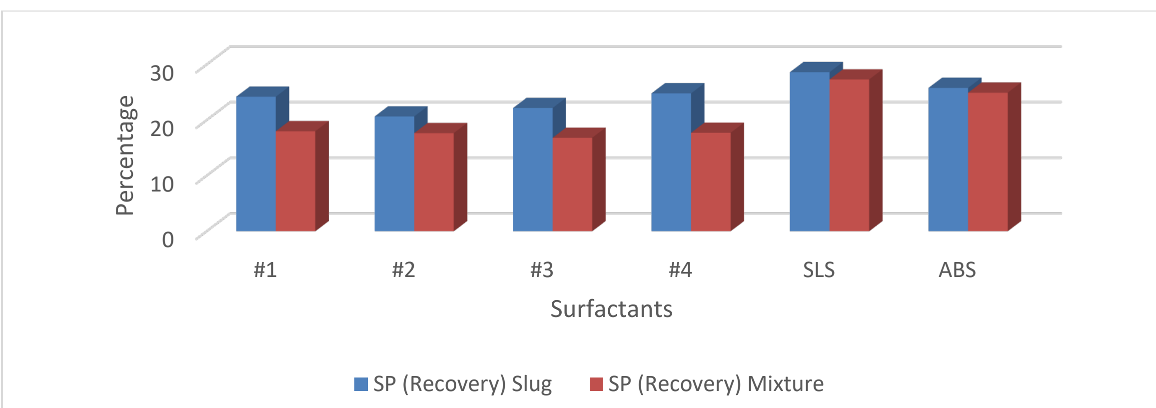

Figure 2. Incremental oil at 0.3wt% surfactant and 500ppm polymer for Case 1 and 2

The results obtained for 0.3%wt of surfactant and 500ppm polymer for the two flooding mechanisms are given in Figure 2. Slug flooding yielded better result when compared with the mixture flooding, though with a small margin especially with the synthetic products. When the concentration of surfactant was increased to 1.0%wt while maintaining the same polymer concentration, appreciable increase in oil recovery was noticed in both cases and there was no significant difference in recovery between the two cases (Figure 4). Polymer concentration was then increased to 2000ppm (Figure 6) which resulted in reduction of oil recovery.

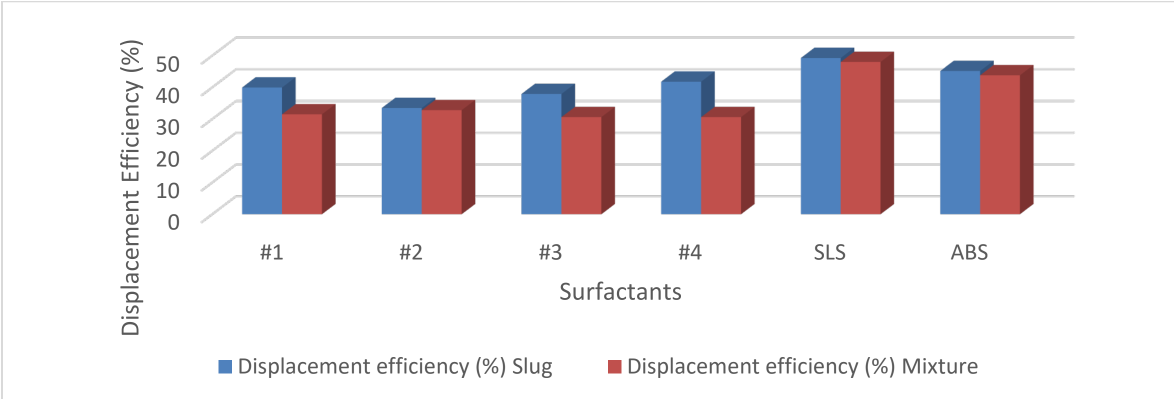

Figure 3. Displacement efficiency at 0.3wt% of surfactant 500ppm polymer for Case 1 and 2

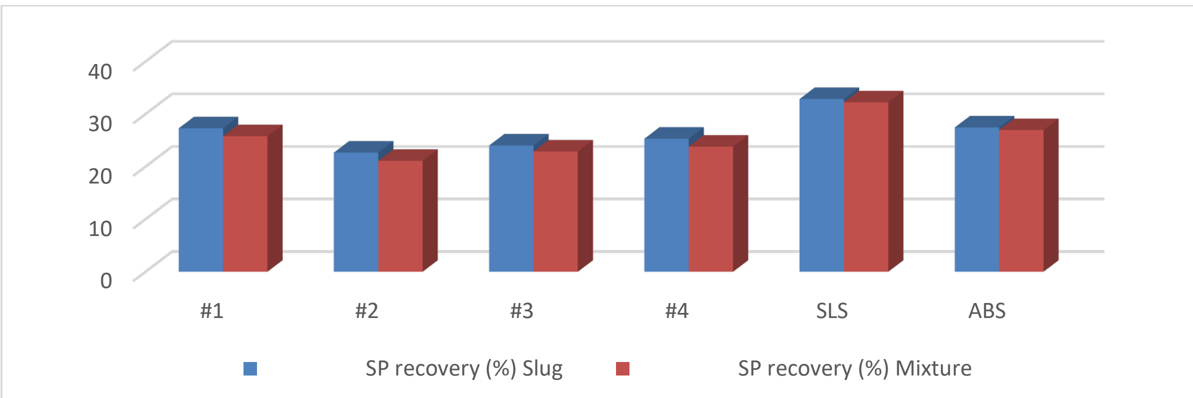

Figure 4. Incremental oil recovery at 1.0wt% surfactant and 500ppm polymer for Case 3 and 4

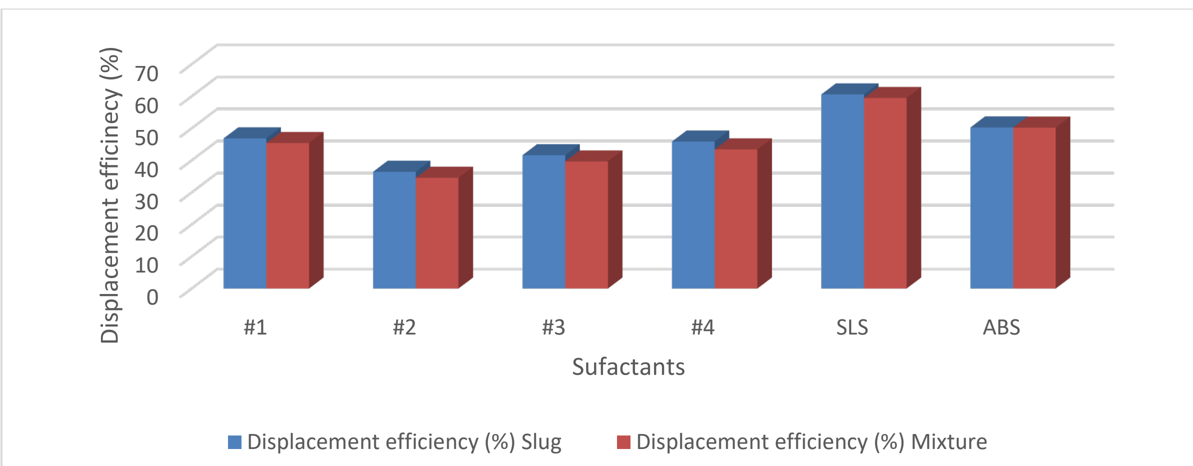

Figure 5. Displacement efficiency at 1.0wt% of surfactant and 500ppm polymer for Case 3 and 4

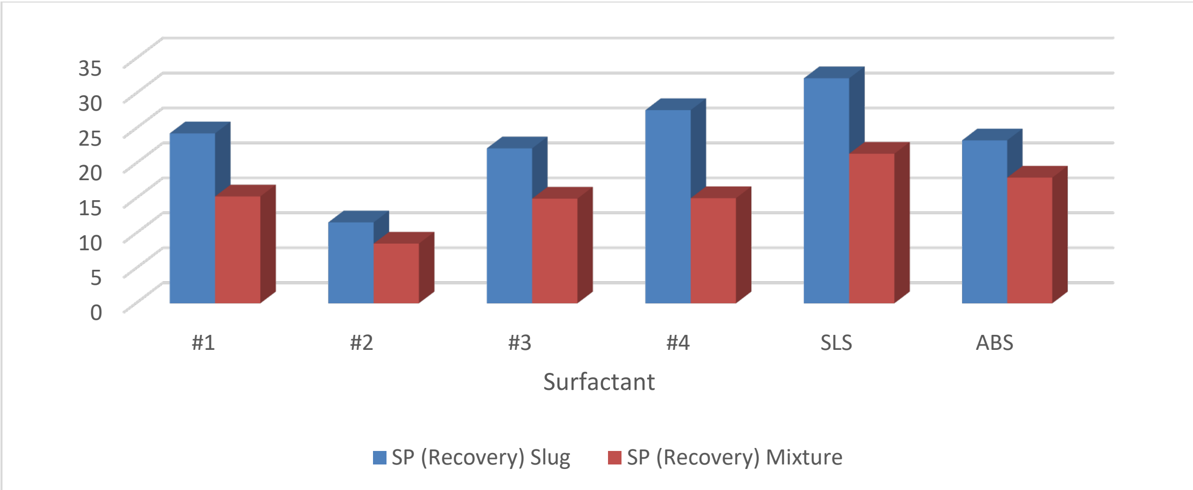

Figure 6. Incremental oil recovery at 1.0wt% surfactant and 2000ppm polymer for Case 5 and 6

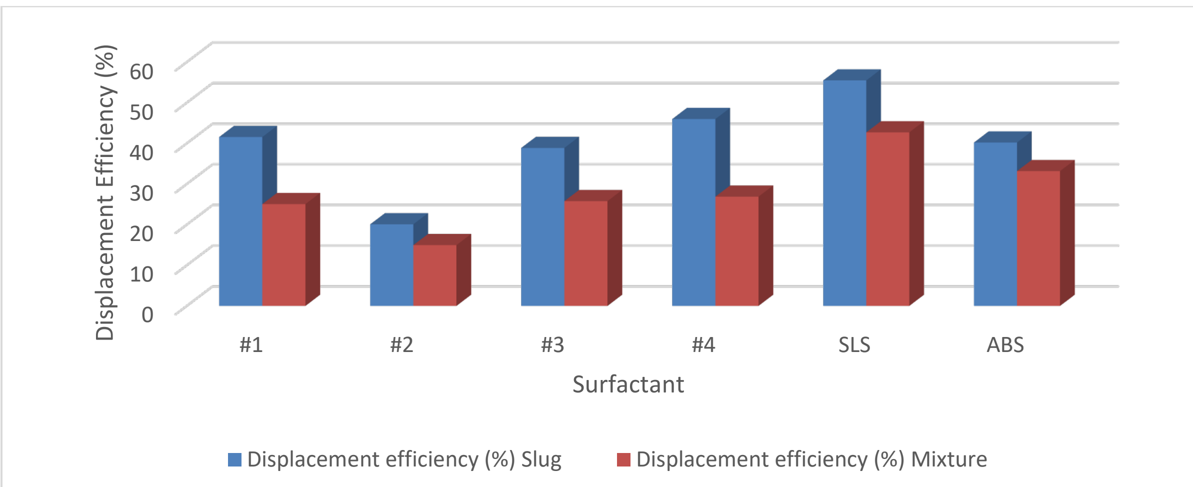

Figure 7. Displacement efficiency at 1wt% surfactant and 2000ppm polymer for Case 5 and 6

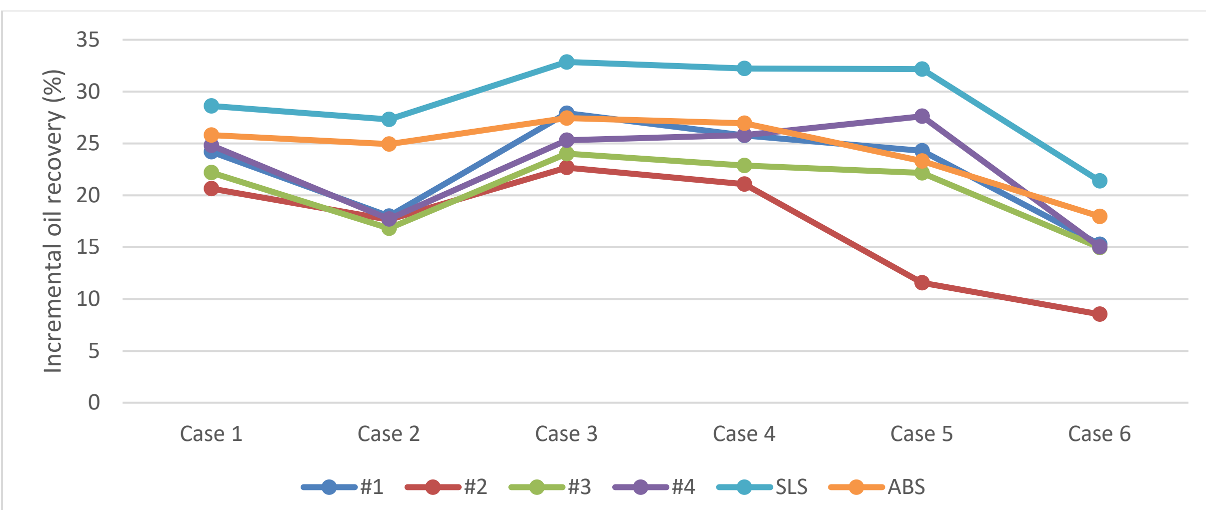

Figure 8. Incremental oil recovery at different concentrations and flooding mechanism

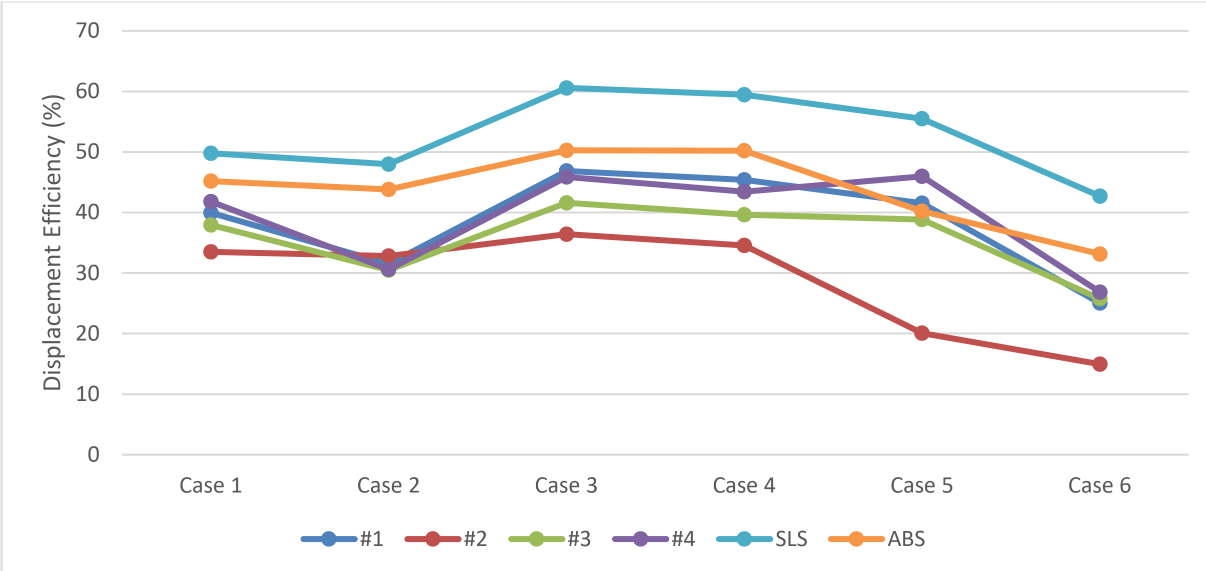

Figure 9. Displacement efficiency at different concentration and flooding mechanism

Figure 8 and 9 show the incremental oil recovery and displacement efficiency at different concentrations and flooding mechanisms.

3.2 Result discussion

Table 8a. Summary of oil recovery separate flooding

	Slug (Separate) flooding					
	0.3%wt and 500ppm		1.0%wt and 500ppm		1.0%wt and 2000ppm	
	Core Perm. (D)	Oil rec. (%)	Core Perm. (D)	Oil rec. (%)	Core Perm. (D)	Oil rec. (%)
#1	105.40	63.68	65.14	69.02	114.74	65.80
#2	91.12	58.78	93.14	60.43	73.71	59.08
#3	84.10	63.68	76.64	66.31	100.77	65.18
#4	114.12	65.41	85.00	70.12	120.18	67.51
SLS	70.65	70.48	73.97	78.62	83.49	74.38
ABS	85.89	68.67	112.17	72.85	78.41	65.32

Table 8b: Summary of oil recovery by mixture flooding

	Mixture flooding					
	0.3%wt and 500ppm		1.0%wt and 500ppm		1.0%wt and 2000ppm	
	Core Perm. (D)	Oil rec. (%)	Core Perm. (D)	Oil rec. (%)	Core Perm. (D)	Oil rec. (%)
#1	77.85	60.80	84.67	68.69	91.49	54.20
#2	88.35	57.17	91.12	60.01	83.32	49.39
#3	93.24	61.68	103.19	65.18	93.39	56.91
#4	104.90	59.83	92.53	68.99	116.08	59.42
SLS	112.04	70.41	119.10	78.06	107.31	71.29
ABS	120.52	68.03	114.22	72.81	76.19	63.78

The results obtained from the experimental procedure adopted have revealed that the major factors that have contributed to decrease and increase in oil recovery recorded at different concentrations of polymer and surfactant are core permeability, sweep efficiency, polymer plugging and IFT values (Table 8a and b).

3.2.1. Case 1 and 2

The concentrations of 0.3%wt and 500ppm, the performance of SLS and ABS seem not to be affected by the flooding mechanism adopted and the permeability difference. For the locally produced surfactants, adopting separate flooding mechanism performs better even with higher permeability cores. This suggests that even though that part of the chemical slug may have been lost to the high permeable zones, the IFT reduction was good enough to increase recovery ahead of mixture flooding. This effect is clearly collaborated with the performance of sample #4; at core permeability of 114.12D, the oil recovery was 65.41% using separate flooding, however, when the lower permeability core 109.90D was used for mixture flooding, oil recovery decreased to 59.83%.

3.2.2. Case 3 and 4

At concentrations of 1.0%wt and 500ppm, permeability difference and flooding mechanism did not affect the oil recoveries by SLS and ABS. Also, for the locally produced surfactants, the discrepancy in oil recoveries observed was not significant. It can be inferred from the result that when the surfactant concentration was increased to 1.0%wt, it favors the two flooding mechanisms irrespective of the permeability difference. However, even with the higher permeability cores used for mixture flooding, the reduction in IFT obtained in the process was able to maintain oil recovery at almost the same rate for the two flooding mechanisms.

3.2.3. Case 5 and 6

Increasing the concentration of polymer to 2000ppm impacted on oil recovery with more effect on mixture flooding. Separate flooding performed far better than the mixture flooding even with the higher permeability cores. This has shown that increasing the concentration of polymer to 2000ppm may have increased the IFT of polymer and surfactant mixture and consequently lead to reduction in oil production.

4. Conclusion

From the results obtained, slug injection of polymer and surfactant yields better results than the injection of mixture of them. Therefore, the injection should follow slug injection process instead of mixture process in SP injection. In the mixture displacement, the performances of locally produced surfactants were greatly reduced by the polymer when compared with synthetic products. The fluid-fluid interaction had negative impact in mixture displacement. Also, in design of polymer surfactant flooding, permeability is an important factor that must be accounted for.

Apart from sample #4, the highest incremental oil recovery was obtained using 1.0wt% surfactant and 500ppm polymer concentrations. SLS and ABS recovered 32.86% and 27.25% of oil initially in place (OIIP) respectively. 27.92%, 22.67% and 24.02% were also recovered by sample #1, #2 and #3 respectively. For sample #4, 27.62% incremental oil recovery was obtained when 1.0wt% surfactant and 2000ppm polymer concentrations were injected. Also, optimum concentration of polymer and surfactant must be used in order to increase the process efficiency. From the experiment, the optimum recovery was obtained with 1.0%wt surfactant and 500ppm polymer concentrations. Sample #1 performed better than other local materials. In all, Sodium Lauryl sulphate (SLS) has the best performance. From the results, it could be deduced that the SP flooding of encapsulated core plugs representing Niger delta heterogeneous formations is a viable project.

Recommendation

Future research work should focus on estimating and monitoring the critical micelle concentration of the surfactants and the rate of surfactant and polymer adsorption to the rock surface.

Nomenclature

ROS *residual oil saturation*
ITF *interfacial tension*
SIS *synthetic imported surfactants*
LPS *Locally produced surfactants*
SLS *sodium lauryl sulphate*
ABS *Akyl benzoate*
PHPAM *Partially hydrolyzed polyacrylamide*
PHPA *Partially hydrolyzed polyacrylamide*
PPA *polyacrylamide*
Sample #1 *Surfactant from palm bunch ash*
Sample #2 *Surfactant from ripped plantain*
Sample #3 *Surfactant from unripped plantain*
Sample #4 *Surfactant from potash (Akanwu)*
IOR *Improved Oil Recovery*
EOR *Enhanced Oil Recovery*
NaCl *Sodium Chloride*
μ_k *Kinematic Viscosity*
μ_d *Dynamic Viscosity*
S_{oi} *Initial Oil Saturation*
S_{wi} *Initial Water Saturation*
PV *Pore Volume*
WF *Water flooding*
N *Oil in Place*
N_p *Cumulative oil production*
$W_{sat.plug}$ *Weight of Saturated Core Plug*
$W_{dry.plug}$ *Weight of Dry Core Plug*
ρ_{brine} *Brine density*
BW *Bulk weight*
∅ *Porosity*
SP *Surfactant polymer flooding*
E_D *Displacement efficiency*
S_{or1} *Residual oil saturation after water flooding*
S_{or2} *Residual oil saturation after surfactant flooding*
$N_{(wf)}$ *Cumulative oil production after water flooding*
$N_{(wf+sp)}$ *Cumulative oil production after surfactant flooding*

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