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Technical Progress Report

DOE Contract No DE-AC22-92 BC14886

Investigation of Oil Recovery Improvement by Coupling
an Interfacial Tension Agent and a Mobility Control Agent
in Light Oil Reservoirs

submitted by
Surtek, Inc.

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Report for the Period of
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I. Objectives of Study

The study will investigate two major areas concerning co-injecting an interfacial tension reduction agent(s) and a mobility control agent into petroleum reservoirs. The first will consist of defining the mechanisms of interaction of an alkaline agent, a surfactant, and a polymer on a fluid-fluid and a fluid-rock basis. The second is the improvement of the economics of the combined technology.

This report examines effect of rock type on oil recovery by an alkaline-surfactant-polymer solutions. This report also begins a series of evaluations to improve the economics of alkaline-surfactant-polymer oil recovery.

II. Summary of Technical Progress

1,000 mg/l NaCl solution was used for coreflooding and chemical make-up. Crude oil was from the Adena field, Morgan County, Colorado; a fluvial deltaic reservoir. Crude oil has an API gravity of 42°. The crude oil with a dead oil viscosity is 3.8 cp at 72°F and 1.3 cp at the 180°F reservoir temperature. All studies performed for this report were performed at 150°F. Dead crude oil viscosity was 1.4 cp at 150°F.

A prior series of corefloods indicated polymer addition to the alkaline-surfactant solution prevented mobility ratio increases and improved oil recovery.^{1,2} Injection of Na₂CO₃-surfactant-polymer recovered up to 30% of the waterflood residual oil.²

The rock matrix effect on alkaline-surfactant-polymer oil recovery was evaluated by performing a series of corefloods using Berea, J Sand, and Muddy Sand cores. Each core was waterflooded to residual oil saturation which varied with rock type but all corefloods used the same crude oil, waters, and chemicals. Waterflood residual oil saturation for Berea averaged 0.318 PV, J Sand averaged 0.377 PV, and Muddy Sand averaged 0.256 PV. In each coreflood, 0.300 PV of either 1.0 wt% Na₂CO₃ plus 0.2 wt% Petrostep B-100 plus 500 mg/l Flopaam 3330S or 0.5 wt% Na₂CO₃ plus 0.1 wt% LXS 420 plus 500 mg/l Flopaam 3330S was injected followed by 0.300 PV of 500 mg/l Flopaam 3330S. A water flush of 1.5 PV followed chemical injection. Berea and Muddy Sand corefloods used radial core while the J Sand corefloods used linear core.

Figures 1 and 2 show the normalized oil recovery versus normalized produced fluid for the two chemical systems. Each coreflood was normalized so that the waterflood oil recovery is 1 and the total fluid injected at the end of the waterflood is 1. Oil recovery with the same oil, water, and alkaline-surfactant-polymer solution varied with rock type. The alkaline-surfactant-polymer oil recovery variance with rock type is dependent on the chemical solution. No difference between Berea and J Sand is seen with the LXS 420-Na₂CO₃-polymer solution but a difference is observed when

Petrostep B-100- Na_2CO_3 -polymer is used. Tertiary oil recoveries as high as 58% of the waterflood oil recovery were observed.

The alkaline-surfactant-polymer flood economics can be improved either by decreasing chemical use or by increasing oil recovery efficiency. Table 1 lists the cost of the alkaline-surfactant-polymer injectants used in a previous coreflood.

Table 1
Injected Cost of Alkaline-Surfactant-Polymer Solution

<u>Chemical</u>	<u>\$/injected bbl</u>	<u>Pore Volume Injected</u>	<u>Cost \$/bbl PV</u>
1.0 wt% Na_2CO_3	0.228	0.30	0.068
0.2 wt% Petrostep B-100	0.665	0.30	0.200
500 mg/l Flopaam 3330S	0.262	0.60	0.157

Polymer and surfactant are the most costly injectants and, therefore, are the key components to effect economics.

The initial series of corefloods to evaluate different injection methods to improve the alkaline-surfactant-polymer economics were ones in which the volume of alkaline-surfactant-polymer solution injected was reduced from 30% PV while maintaining total mobility control fluid volume at 60% PV. Radial corefloods using Berea core were performed in which 0, 10, 20, and 30 % PV of 1.0 wt% Na_2CO_3 plus 0.2 wt% Petrostep B-100 plus 500 mg/l Flopaam 3330S was injected followed by 60, 50, 40, and 30% PV 500 mg/l Flopaam 3330S. A water flush of 1.5 to 2 PV followed chemical injection. The incremental oil recovery for each of the corefloods is shown as percent of initial oil saturation (S_{oi}) and percent of waterflood residual oil saturation (S_{or}) in Figure 3. The oil recovery is approaching an asymptote between 20 and 30% PV alkaline-surfactant-polymer solution injected. Table 1 shows the cost per incremental barrel of oil.

Table 2
Cost per Incremental Barrel Oil

<u>Volume Injected ASP:Polymer Drive % PV:% PV</u>	<u>Injectant Cost \$/bbl PV</u>	<u>Incremental Oil Recovery PV</u>	<u>Cost per Incremental bbl \$/bbl</u>
0:60	0.157	0.009	17.44
10:50	0.246	0.027	9.12
20:40	0.335	0.101	3.32
30:30	0.425	0.106	4.01

In this case, the most economic injection scenario would be to inject 0.20 PV alkaline-surfactant-polymer solution followed by 0.40 PV polymer solution.

With surfactant being the most expensive component in the Na_2CO_3 -Petrostep B-100-Flopaam 3330S injection scheme, a series of corefloods were performed to evaluate a surfactant taper within the alkaline-surfactant-polymer slug. The total volume of 1.0 wt% Na_2CO_3 plus Petrostep B-100 plus 500 mg/l Flopaam 3330S injected was 0.3 PV followed by 0.3 PV of 500 mg/l Flopaam 3330S in each case. Initial surfactant concentration was 0.2 wt%. Surfactant concentration was tapered to 0.0 wt% over the 30% PV injected in a linear fashion such that the total mass of surfactant injected was 80 and 68% of the base coreflood. The 30% PV:30% PV, (1.0 wt% Na_2CO_3 plus 0.2 wt% Petrostep B-100 plus 500 mg/l Flopaam 3330S):(500 mg/l Flopaam 3330), coreflood discussed previously is the base coreflood. Alkali and polymer concentration were maintained at design values as the surfactant concentration was reduced. The oil recovery versus cumulative produced fluid comparison is depicted in Figure 4. Again, the oil recoveries and volume injected are normalized to the ending waterflood values for each coreflood. Oil recovery declines as the surfactant is tapered proportional to the mass of surfactant injected. Economic changes are listed in Table 3.

Table 3
Surfactant Taper
Cost per Incremental Barrel Oil

Mass of Surfactant Injected % of Base	Injectant Cost \$/bbl PV	Incremental Oil Recovery PV	Cost per Incremental bbl \$/bbl
100	0.425	0.106	4.01
80	0.406	0.075	5.41
68	0.365	0.048	7.60

Tapering surfactant concentration did not improve alkaline-surfactant-polymer economics.

III. Continued Evaluations

Continued evaluations will study methods to improve alkaline-surfactant-polymer economics. Altering polymer and alkali concentrations will be investigated.

IV. References

1. Pitts, M.J.: "Investigation of Oil Recovery Improvement by Coupling an Interfacial Tension Agent and a Mobility Control Agent in Light Oil Reservoirs", April through June 1994 Quarterly Report.
2. ibid, July through September 1994 Quarterly Report.

Figure 1

Sand Type Effect on Oil Recovery by Alkaline-Surfactant-Polymer Solutions

Figure 2

Sand Type Effect on Oil Recovery by Alkaline-Surfactant-Polymer Solutions

Figure 3

Volume of Alkaline-Surfactant-Polymer Solution
Injection versus Oil Recovery

Figure 4

Effect of Tapering the Surfactant Component of the
Alkaline-Surfactant-Polymer Solution on Oil Recovery