SURTEK

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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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Anticipated Completion Date: September 30, 1995

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Contracting Officer's Representative: Mary Sue Price

Report for the Period of
January to March 1995

Two series of corefloods were performed to improve alkaline-surfactant-polymer oil recovery economics. In these series of corefloods, the objective was to increase oil recovery by changing the chemical injection sequence. An alkaline gradient was evaluated in the first series of corefloods. Radial corefloods using Berea core were performed in which a pre-flush of alkaline-polymer solution was injected before the alkaline-surfactant-polymer solution. 30% pore volume (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 30% PV 500 mg/l Flopaam 3330S. A 5% PV 2.0 wt% Na_2CO_3 plus 500 mg/l Flopaam 3330S followed by 5% PV 1.5 wt% Na_2CO_3 plus 500 mg/l Flopaam 3330S was injected prior to the alkaline-surfactant-polymer solution in the coreflood with an alkaline-polymer pre-flush. A water flush of 1.5 to 2 PV followed chemical injection. The pre-flush objective was to inject sufficient alkali to satiate consumption and to force the surfactant to go through optimum interfacial tension and phase behavior states. Figure 1 compares radial coreflood cumulative oil recovery and oil cut of a coreflood with a graded alkaline-polymer pre-flush with a coreflood without an alkaline gradient. Incremental oil recovery increased 24% from 0.106 PV (30.3% waterflood residual oil) to 0.131 PV (38.6% waterflood residual oil) when an alkaline-gradient pre-flush was injected.

The effect on the oil recovery economics of an alkaline-polymer pre-flush is shown in Table 2. Oil recovery as well as the mass of alkali and polymer injected increased making the cost per incremental barrel of oil unchanged.

Table 2
Cost per Incremental Barrel Oil

ASP Injection Sequence	Injectant Cost \$/bbl PV	Incremental Oil Recovery PV	Cost per Incremental bbl \$/bbl
no gradient	0.425	0.106	4.01
alkali gradient as pre-flush	0.532	0.131	4.06
alkali gradient in ASP slug	0.451	0.122	3.69

Cost of an alkaline-polymer pre-flush is additional time as well as chemicals. Therefore, the second series of corefloods investigated placing the alkaline gradient within the alkaline-surfactant-polymer slug. In this case, 5% PV of 2.0 wt% Na_2CO_3 plus 0.2 wt% Petrostep B-100 plus 500 mg/l Flopaam 3330S was injected followed by 5% PV of 1.5 wt% Na_2CO_3 plus 0.2 wt% Petrostep B-100 plus 500 mg/l Flopaam 3330S, 20% PV of 1.0 wt% Na_2CO_3 plus 0.2 wt% Petrostep B-100 plus 500 mg/l Flopaam 3330S and ultimately by 30% PV 500 mg/l Flopaam 3330S. A water flush of 1.5 to 2 PV followed chemical injection. Figure 2 shows the comparison of the corefloods. Placing the alkaline gradient within the alkaline-surfactant-polymer slug has little effect on oil recovery but decreased the cost per incremental barrel as shown in Table 2.

Figure 3 depicts the incremental increase due to an alkaline gradient within the alkaline-surfactant-polymer slug for a Na_2CO_3-LXS 420-Flopaam 3330S chemical combination. In this case, incremental oil recovery due to the alkaline-surfactant-polymer solution increased by 116% from 0.065 PV (19.4% waterflood residual oil) to 0.141 PV (43.6% waterflood residual oil) when an alkaline gradient was included in the alkaline-surfactant-polymer slug. Cost per incremental barrel of oil decreased from $6.37 to $2.89.

The second series of corefloods was performed to determine if incremental oil recovery can be increased either by extending the polymer drive volume with a concentration taper or by increasing the polymer concentration initially in alkaline-surfactant-polymer solution with a polymer concentration taper through the polymer drive. In both cases, the mass of polymer injected was identical to the prior evaluations. Figure 4 compares an alkaline gradient alkaline-surfactant-polymer followed with a block polymer drive coreflood with a coreflood having an extended polymer drive with a polymer concentration taper in addition to the alkaline gradient. The extended polymer drive followed by a polymer taper injection sequence was 5% PV 2.0 wt% Na_2CO_3 plus 0.2 wt% Petrostep B-100 plus 500 mg/l Flopaam 3330S followed by 5% PV of 1.5 wt% Na_2CO_3 plus 0.2 wt% Petrostep B-100 plus 500 mg/l Flopaam 3330S, 20% PV of 1.0 wt% Na_2CO_3 plus 0.2 wt% Petrostep B-100 plus 500 mg/l Flopaam 3330S and ultimately by a polymer drive consisting of 15% PV 500 mg/l Flopaam 3330S followed by 15% PV 330 mg/l Flopaam 3330S followed by 15% PV 160 mg/l Flopaam 3330S. A water flush of 1.5 to 2 PV followed chemical injection. No difference in oil recovery is observed.

Figure 5 compares an alkaline gradient alkaline-surfactant-polymer flood followed by a block concentration polymer drive with a coreflood having a higher initial polymer concentration and a polymer concentration taper beginning in the alkaline gradient-surfactant-polymer slug which continued through the polymer drive. The higher initial polymer concentration, polymer taper beginning in the alkaline gradient-surfactant-polymer slug injection sequence was 5% PV 2.0 wt% Na_2CO_3 plus 0.2 wt% Petrostep B-100 plus 985 mg/l Flopaam 3330S followed by 5% PV of 1.5 wt% Na_2CO_3 plus 0.2 wt% Petrostep B-100 plus 980 mg/l Flopaam 3330S, 10% PV of 1.0 wt% Na_2CO_3 plus 0.2 wt% Petrostep B-100 plus 725 mg/l Flopaam 3330S, 10% PV of 1.0 wt% Na_2CO_3 plus 0.2 wt% Petrostep B-100 plus 500 mg/l Flopaam 3330S and ultimately by a polymer drive consisting of 10% PV 500 mg/l Flopaam 3330S followed by 10% PV 300 mg/l Flopaam 3330S followed by 10% PV 160 mg/l Flopaam 3330S. A water flush of 1.5 to 2 PV followed chemical injection. In agreement with previous investigations,[1] no additional oil recovery was observed by increasing the concentration of polymer in the alkaline-surfactant-polymer slug.

III. Continued Evaluations

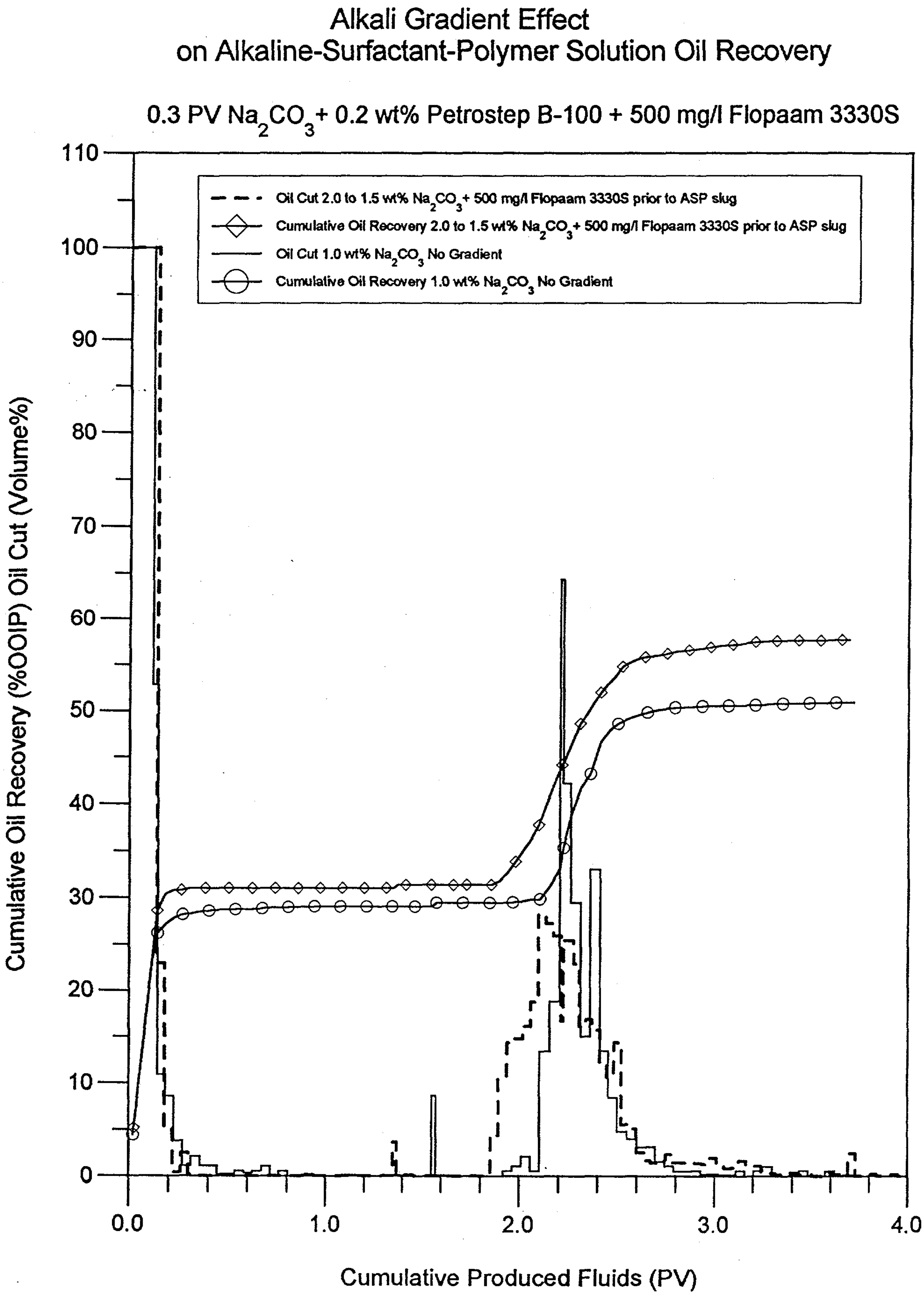
Continued evaluations will study methods to improve alkaline-surfactant-polymer economics. Altering polymer concentration in the polymer drive will be studied in more detail.

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", Second Annual Report October 1993 to September 1994, DOE/BC/14886-9.

2. 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.

Figure 1



Alkali Gradient Effect
on Alkaline-Surfactant-Polymer Solution Oil Recovery
0.3 PV Na2CO3 + 0.2 wt% Petrostep B-100 + 500 mg/l Flopaam 3330S
Oil Cut 2.0 to 1.5 wt% Na2CO3 + 500 mg/l Flopaam 3330S prior to ASP slug
Cumulative Oil Recovery 2.0 to 1.5 wt% Na2CO3 + 500 mg/l Flopaam 3330S prior to ASP slug
Oil Cut 1.0 wt% Na2CO3 No Gradient
Cumulative Oil Recovery 1.0 wt% Na2CO3 No Gradient
Cumulative Oil Recovery (%OOIP) Oil Cut (Volume%)
110
100
90
80
70
60
50
40
30
20
10
0
0.0
1.0
2.0
3.0
4.0
Cumulative Produced Fluids (PV)

Figure 2

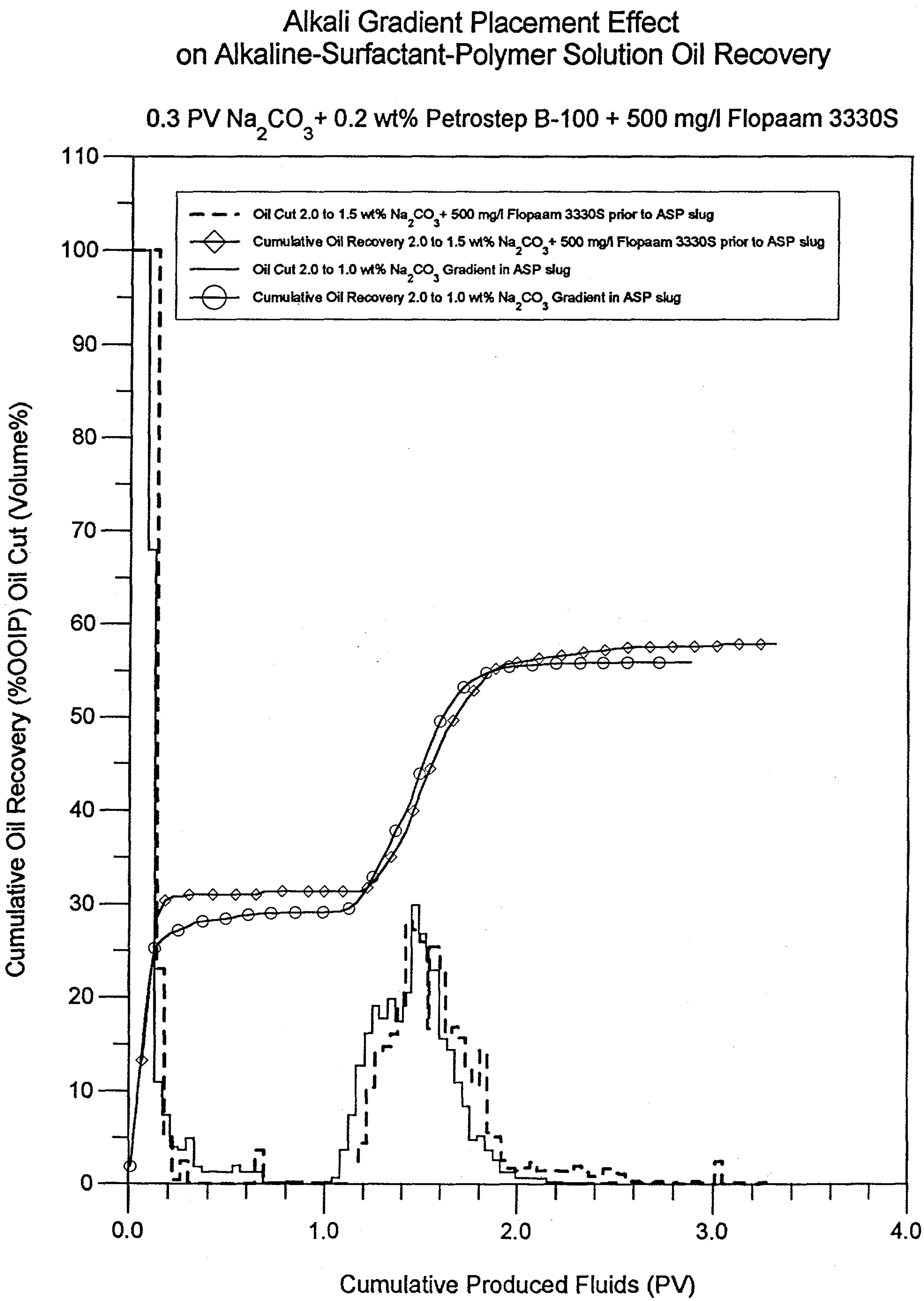
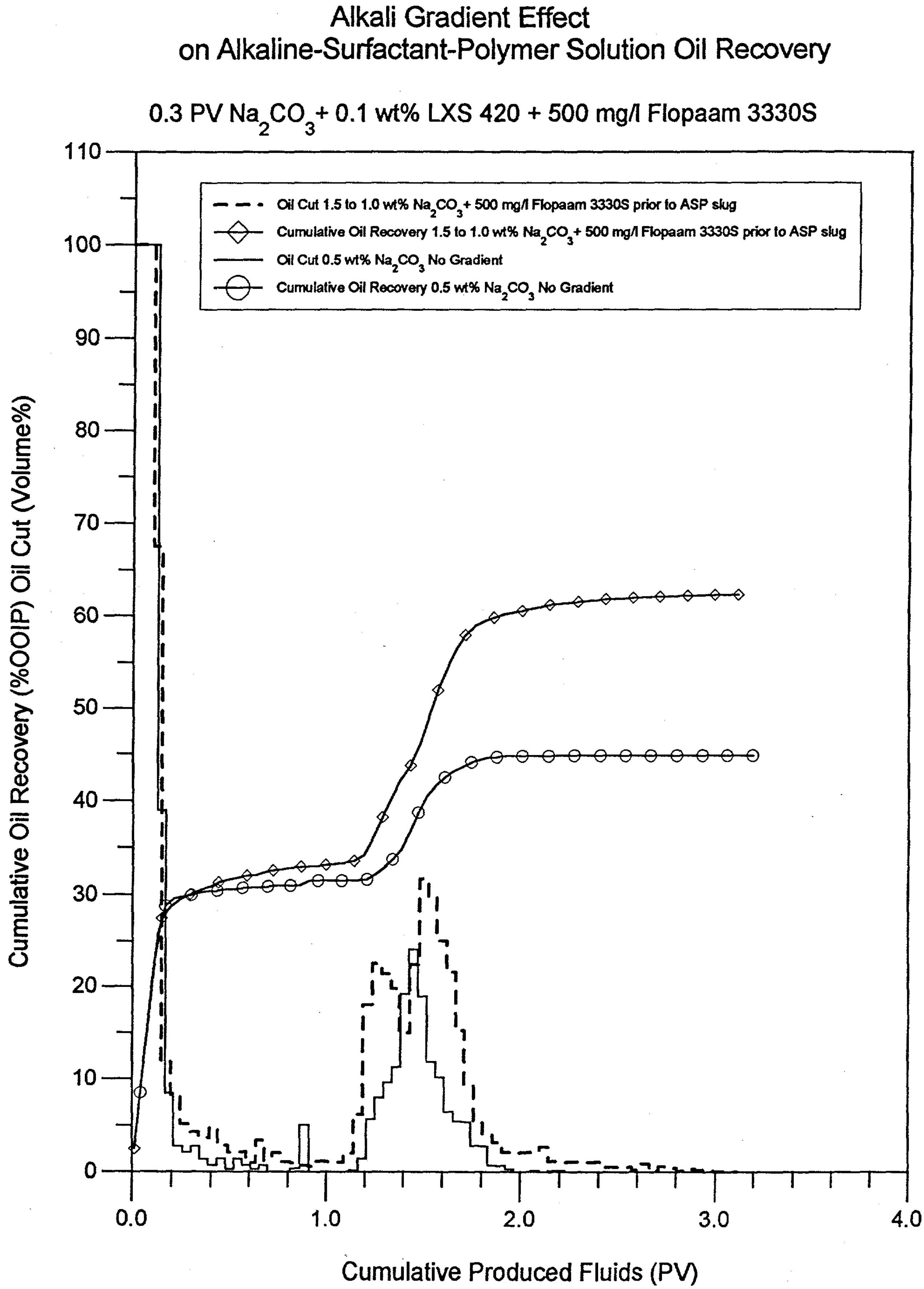

Alkali Gradient Placement Effect
on Alkaline-Surfactant-Polymer Solution Oil Recovery
0.3 PV Na2CO3 + 0.2 wt% Petrostep B-100 + 500 mg/l Flopaam 3330S
Oil Cut 2.0 to 1.5 wt% Na2CO3 + 500 mg/l Flopaam 3330S prior to ASP slug
Cumulative Oil Recovery 2.0 to 1.5 wt% Na2CO3 + 500 mg/l Flopaam 3330S prior to ASP slug
Oil Cut 2.0 to 1.0 wt% Na2CO3 Gradient in ASP slug
Cumulative Oil Recovery 2.0 to 1.0 wt% Na2CO3 Gradient in ASP slug
Cumulative Oil Recovery (%OOIP) Oil Cut (Volume%)
110
100
90
80
70
60
50
40
30
20
10
0
0.0
1.0
2.0
3.0
4.0
Cumulative Produced Fluids (PV)

Figure 3



Alkali Gradient Effect
on Alkaline-Surfactant-Polymer Solution Oil Recovery
0.3 PV Na2CO3+ 0.1 wt% LXS 420 + 500 mg/l Flopaam 3330S
Oil Cut 1.5 to 1.0 wt% Na2CO3 + 500 mg/l Flopaam 3330S prior to ASP slug
Cumulative Oil Recovery 1.5 to 1.0 wt% Na2CO3 + 500 mg/l Flopaam 3330S prior to ASP slug
Oil Cut 0.5 wt% Na2CO3 No Gradient
Cumulative Oil Recovery 0.5 wt% Na2CO3 No Gradient
Cumulative Oil Recovery (%OOIP) Oil Cut (Volume%)
0
10
20
30
40
50
60
70
80
90
100
110
0.0
1.0
2.0
3.0
4.0
Cumulative Produced Fluids (PV)

Figure 4

Polymer Drive Solution Concentration Taper Effect on Alkaline-Surfactant-Polymer Solution Oil Recovery

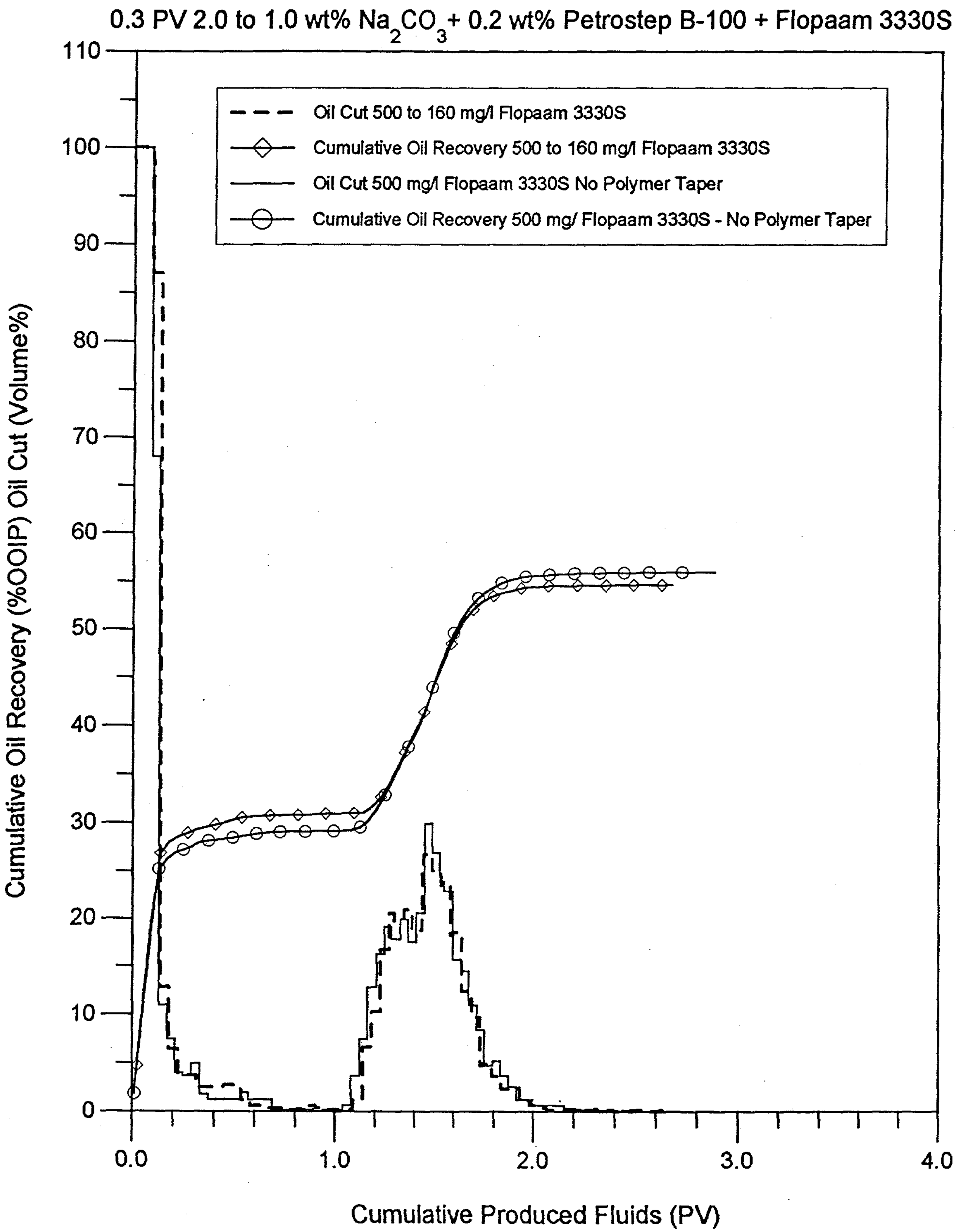


Figure 5

Effect of Higher Initial Polymer Concentration with Polymer Taper beginning in the Alkaline-Surfactant-Polymer Solution on Oil Recovery

0.3 PV 2.0 to 1.0 wt% Na_2CO_3 + 0.2 wt% Petrostep B-100 + Flopaam 3330S