Coupling the Alkaline-Surfactant-Polymer Technology and The Gelation Technology to Maximize Oil Production

Semi-Annual Technical Progress Report

April 1, 2005
To
September 30, 2005

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October 2005

Award Number DE-FC26-03NT15411

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Abstract

Gelation technologies have been developed to provide more efficient vertical sweep efficiencies for flooding naturally fractured oil reservoirs or more efficient areal sweep efficiency for those with high permeability contrast "thief zones". The field proven alkaline-surfactant-polymer technology economically recovers 15% to 25% OOIP more oil than waterflooding from swept pore space of an oil reservoir. However, alkaline-surfactant-polymer technology is not amenable to naturally fractured reservoirs or those with thief zones because much of injected solution bypasses target pore space containing oil. This work investigates whether combining these two technologies could broaden applicability of alkaline-surfactant-polymer flooding into these reservoirs.

A prior fluid-fluid report discussed interaction of different gel chemical compositions and alkaline-surfactant-polymer solutions. Gel solutions under dynamic conditions of linear corefloods showed similar stability to alkaline-surfactant-polymer solutions as in the fluid-fluid analyses. Aluminum-polyacrylamide, flowing gels are not stable to alkaline-surfactant-polymer solutions of either pH 10.5 or 12.9. Chromium acetate–polyacrylamide flowing and rigid flowing gels are stable to subsequent alkaline-surfactant-polymer solution injection. Rigid flowing chromium acetate-polyacrylamide gels maintained permeability reduction better than flowing chromium acetate-polyacrylamide gels. Silicate-polyacrylamide gels are not stable with subsequent injection of either a pH 10.5 or a 12.9 alkaline-surfactant-polymer solution. Chromium acetate–xanthan gum rigid gels are not stable to subsequent alkaline-surfactant-polymer solution injection. Resorcinol-formaldehyde gels were stable to subsequent alkaline-surfactant-polymer solution injection. When evaluated in a dual core configuration, injected fluid flows into the core with the greatest effective permeability to the injected fluid. The same gel stability trends to subsequent alkaline-surfactant-polymer injected solution were observed.

Aluminum citrate-polyacrylamide, resorcinol-formaldehyde, and the silicate-polyacrylamide gel systems did not produce significant incremental oil in linear corefloods. Both flowing and rigid flowing chromium acetate-polyacrylamide gels and the xanthan gum-chromium acetate gel system produced incremental oil with the rigid flowing gel producing the greatest amount. Higher oil recovery could have been due to higher differential pressures across cores. None of the gels tested appeared to alter alkaline-surfactant-polymer solution oil recovery. Total waterflood plus chemical flood oil recovery sequence recoveries were all similar.

Chromium acetate-polyacrylamide gel used to seal fractured core maintain fracture closure if followed by an alkaline-surfactant-polymer solution. Chromium acetate gels that were stable to injection of alkaline-surfactant-polymer solutions at 72°F were stable to injection of alkaline-surfactant-polymer solutions at 125°F and 175°F in linear corefloods. Chromium acetate-polyacrylamide gels maintained diversion capability after injection of an alkaline-surfactant-polymer solution in stacked; radial coreflood with a common well bore. Xanthan gum-chromium acetate gels maintained gel integrity in linear corefloods after injection of an alkaline-surfactant-polymer solution at 125°F. At 175°F, Xanthan gum-chromium acetate gels were not stable either with or without subsequent alkaline-surfactant-polymer solution injection.

Numerical simulation demonstrated that reducing the permeability of a high permeability zone of a reservoir with gel improved both waterflood and alkaline-surfactant-polymer flood oil recovery. A Minnelusa reservoir with both A and B sand production was simulated. A and B sands are separated by a shale layer. A sand and B sand waterflood oil recovery was improved by 196,000 bbls when a gel was placed in the B sand. A sand and B sand alkaline-surfactant-polymer flood oil recovery was improved by 596,000 bbls when a gel was placed in the B sand. Alkaline-surfactant-polymer flood oil recovery improvement over a waterflood was 392,000 bbls. Placing a gel into the B sand prior to an alkaline-surfactant-polymer flood resulted in 989,000 bbl more oil than only water injection.

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Introduction

Gelation technologies provide more efficient vertical sweep efficiencies for flooding naturally fractured oil reservoirs or more efficient areal sweep efficiency for those with high permeability contrast "thief zones". Field proven alkaline-surfactant-polymer technology economically recovers 15% to 25% OOIP more oil than waterflooding from swept pore space of an oil reservoir. However, alkaline-surfactant-polymer technology is not amenable to naturally fractured reservoirs or those with thief zones because much of the injected solution bypasses target pore space containing oil. This work investigates whether combining these two technologies could broaden applicability of alkaline-surfactant-polymer flooding.

Executive Summary

Chromium acetate-polyacrylamide gel used to close fractures and divert fluid into the matrix maintains diversion capability after injection of an alkaline-surfactant-polymer solution. Linear corefloods indicate that the chromium acetate-polyacrylamide gel integrity is maintained after injecting alkaline-surfactant-polymer solution at 72, 125, and 175^{o}F. Xanthan gum-chromium acetate gels on the other hand were only stable at 72 and 125^{o}F. Numerical simulation of applying a gel treatment to a Minnelusa reservoir with two sands separated by shale indicates that prior treatment of the higher permeability sand with gel will recover additional oil. Waterflood oil recovery is improved by 196,000 bbls with gel treatment. Alkaline-surfactant-polymer flood oil recovery is improved by 596,000 bbls with prior gel injection.

Experimental

Evaluations performed at 72^{o}F used Big Sinking crude oil supplied by Bretagne in Lexington, Kentucky. Big Sinking crude oil is a 42^{o} API gravity, 3 cp crude oil. It's characteristics have been described elsewhere.[1] Evaluations at 125^{o}F and 175^{o}F used a 19.4^{o} API gravity crude oil with a viscosity of 30 and 13 cp at the elevated temperatures, respectively. Polymers used in the linear corefloods are listed in Table 1. Chemicals were dissolved in 1.0 wt% sodium chloride.

Table 1
Polymers Used in Gelation Linear Corefloods

Polymer Name	Type/Degree of Hydrolysis	Supplier
Flocon 4800	xanthan gum	SNF Floerger
Alcoflood 1275A	polyacrylamide/30%	Ciba Specialty Chemicals
HiVis 350	polyacrylamide/30%	Tiorco, Inc.
Watercut 204	polyacrylamide/7%	Tiorco, Inc.

Linear core floods were performed using 2 inches diameter by 5 inches long, unfired Berea sandstone. Radial corefloods used 6 inches diameter by 2 inches high, unfired Berea sandstone. Table 2 lists the core properties. Fractured linear core was developed by chisel etching a straight line cut along the length of core sides and faces. Continual light tapping of the chisel along the etched line eventually created a fracture.

Table 2

Berea Core Properties

Coreflood	100% NaCl Brine Saturated Permeability $K_{T,\,abs}$(md)	Porosity(%)	---Oil Saturation--- $S_{oi}(V_P)$	$S_{or}(V_p)$
Fractured Core Linear Coreflood				
Cr^{+3}- PHPA rigid – NaOH (prior to cutting fracture)	595	22.8	0.562	0.349
175°F Linear Corefloods				
Cr^{+3}-XG rigid - NaOH	290	22.6	0.609	0.236
Cr^{+3}- PHPA rigid - NaOH	425	23.1	0.582	0.211
125°F Linear Corefloods				
Cr^{+3}-XG rigid - NaOH	502	22.8	0.791	0.382
Cr^{+3}- PHPA rigid - NaOH	555	23.3	0.712	0.336
Radial Corefloods				
dual core, common well bore, same core holder				
Cr^{+3}-PHPA rigid flowing – NaOH	631	23.0	0.541	0.284
Cr^{+3}-PHPA rigid flowing - Na_2CO_3	58	17.9	0.510	0.355

S_{oi} and S_{or} are initial and waterflood residual oil saturation, respectively. PHPA is partially hydrolyzed polyacrylamide, and XG is xanthan gum.

Single core linear coreflood injected fluid sequence is listed below. Corefloods were performed at designated temperature.

1. Saturate core with 1.0 wt% NaCl by evacuation and determine porosity and pore volume
2. Inject 1.0 wt% NaCl and determine the absolute permeability to water (k_{abs}).
3. Inject crude oil to immobile water and determine the effective permeability to oil at immobile water (k_{orw}).
4. Inject 1.0 wt% NaCl at 12 ft/day fluid frontal advance rate to residual oil and determine the effective permeability to water at residual oil (k_{orw}).
5. Inject gel fluids at 12 ft/day.
6. Stop injection. Pull core holder apart, clean gel out of injection and production lines. Fill injection lines with 1.0 wt% NaCl before assembling core holder.
7. Re-assemble core holder and allow gel to form overnight with no flow.
8. Inject 1.0 wt% NaCl at 12 ft/day to stable pressures.
9. Inject 1.0 wt% NaOH plus 0.06 wt% active ORS-46HF plus 1300 mg/L Alcoflood 1275A at 12 ft/day. Inject 5 to 10 pore volumes.
10. Shut-in overnight.
11. Resume ASP solution injection at 12 ft/day. Inject 1 to 2 pore volumes.
12. Inject 1.0 wt% NaCl at 12 ft/day for 5 to 10 pore volumes to get stable pressures and determine permeability change from step 8.

Differential pressures were measured from the core injection face to one inch from the injection face, and from injection face to production face. Differential pressure from one inch behind the injection face to production face of the core was calculated by difference between the two measured values.

Single fractured core linear coreflood injected fluid sequence is.

1. Repeat steps 1 through 3 of the single linear coreflood procedure.
2. Remove core from core holder and fracture core.
3. Place fractured core into core holder. Put overburden pressure on core and inject Big Sinking crude oil and determine k_{orw}.
4. Inject crude oil to immobile water at 30 ft/day and determine the effective permeability to oil at immobile water (k_{orw}).
5. Inject 1.7 pore volumes of 1.0 wt% NaCl at 4 ft/day fluid frontal advance rate to residual oil and determine k_{wro}.
6. Inject at 4 ft/day 0.5 pore volumes of Marcit gel (7500 mg/L WaterCut 204: 2425 mg/L WaterCut 684 or 250 mg/L Cr^{+3}).
7. Inject 0.05 pore volume of 1.0 wt% NaCl. Stop injection. Clean out injection and production lines. Fill injection lines with 1.0 wt% NaCl. Do not take the core holder apart.
8. Shut-in for two days.
9. Inject 1.0 wt% NaCl at 4 ft/day for 7.4 pore volumes to get stable pressures, flush gel from core, and get resistance factor.
10. Inject 7.1 pore volumes 1.0 wt% NaOH plus 0.06 wt% active ORS-46HF plus 1300 mg/L Alcoflood 1275A at 4 ft/day.
11. Inject 1.0 wt% NaCl at 4 ft/day for 6.5 pore volumes to get stable pressures and flush ASP-gel from core.

Differential pressures were measured from the core injection face to production face.

Dual individual core radial coreflood with a common manifold injected fluid sequence is listed below.

Separate radial core holders were used in steps 1 – 3.

1. Saturate core with 1.0 wt% NaCl and determine porosity and pore volume.
2. Inject 1.0 wt% NaCl and determine the absolute permeability to water (k_{abs}).
3. Inject Big Sinking crude oil to immobile water and determine k_{orw}.

Place core in stacked core radial core holder. A piece of cellulose paper was placed between the core to facilitate capillary continuity. An O-ring was placed on the outer edge of the cores at their junction that will seal to the annulus edge to facilitate separate collection of fluids from each core. Place an overburden of 1000 psi on the cores. Stacked core injection steps 4 - 10 - fluid frontal advance rates are summed height, average porosity, and average diameter for two cores.

4. Stack cores so that a common well bore is present.
5. Inject 1.0 wt% NaCl at 5 ft/day fluid frontal advance rate to residual oil saturation and determine k_{orw} for each core.

6. Inject gel fluids at 5 ft/day 0.7 pore volumes of the high permeability core and monitor injection pressure.
7. Inject 0.05 pore volumes of the high permeability core of 1.0 wt% NaCl at 5 ft/day.
8. Stop injection and allow gel to form for two days.
9. Inject 1.0 wt% NaCl at 5 ft/day for 5 pore volumes and determine resistance factor.
10. Inject 1.0 wt% NaOH plus 0.10 wt% active ORS-60HF plus 1300 mg/L Alcoflood 1275A solution at 5ft/day and monitor injection pressure.
11. Inject 1.0 wt% NaCl at 5 ft/day for 5 pore volumes and determine residual resistance factor.

Produced fluids were collected in test tubes on a fraction collector.

Resistance factor for all corefloods was calculated according to $RF_i = \frac{(\Delta P / q)_i}{(\Delta P / q)_{baseline}}$, where ΔP is differential pressure, psi, and q is injection rate, ml/hr. Baseline values are after 1.0 wt% NaCl injection at S_{orw} and before initial chemical injection.

Oil saturation is determined by mass balance of injected and produced fluids. Final oil saturation was cross-checked by extraction of fluids by hot toluene.

Gel chemical compositions are listed in Table 3.

Table 3

Gel Chemical Composition

Gel	Polymer Type	mg/L	Cross Linking Agent (Bulk) Type	mg/L
72°F Corefloods				
Cr^{+3}-Xanthan Gum	Flocon 4800	5,000	Watercut 684	3,250
Cr^{+3}-PHPA rigid flowing	Watercut 204	7,500	Watercut 684	2,425
125°F Corefloods				
Cr^{+3}-Xanthan Gum	Flocon 4800	5,000	Watercut 684	3,250
Cr^{+3}-PHPA rigid flowing	Watercut 204	5,000	Watercut 684	1,590
175°F Corefloods				
Cr^{+3}-Xanthan Gum	Flocon 4800	2,000	Watercut 684	950
Cr^{+3}-PHPA rigid flowing	Watercut 204	3,000	Watercut 684	1,430

Gel solutions were mixed in a 1.0 wt% NaCl solution in an injection tank as a single solution just prior to injection.

Alkaline-Surfactant-Polymer Solutions

A 1.0 wt% NaOH plus 0.06 wt% ORS-46HF plus 1300 mg/L Alcoflood 1275A solution was used with Big Sinking oil in the 72°F corefloods. ORS-46HF was supplied by OCT, Inc. Interfacial tension between the alkaline-surfactant-polymer solution and Big Sinking crude oil was 0.191 dyne/cm. A 1.0 wt% NaOH plus 0.10 wt% ORS-60HF plus 1300 mg/L Alcoflood 1275A solution was used with the 19.4° API gravity crude oil in the 125°F and 175°F corefloods.

Interfacial tension between the alkaline-surfactant-polymer solution and 19.4° API crude oil was 0.001 dyne/cm.

Results and Discussion

Fractured Core Polyacrylamide-Chromium Acetate Gel Linear Corefloods

Fractured core linear corefloods are a continuation of the prior study to determine if gel solutions placed in a fracture are stable to subsequent injection of an alkaline-surfactant-polymer solution.[2] Injected gel mixture was 7500 mg/L Flopaam 4800 plus 250 mg/L Watercut 684 as Cr^{+3}. Alkaline-surfactant-polymer solution injected was 1.0 wt% NaOH plus 0.06 wt% active ORS-46HF plus 1300 mg/L Alcoflood 1275A.

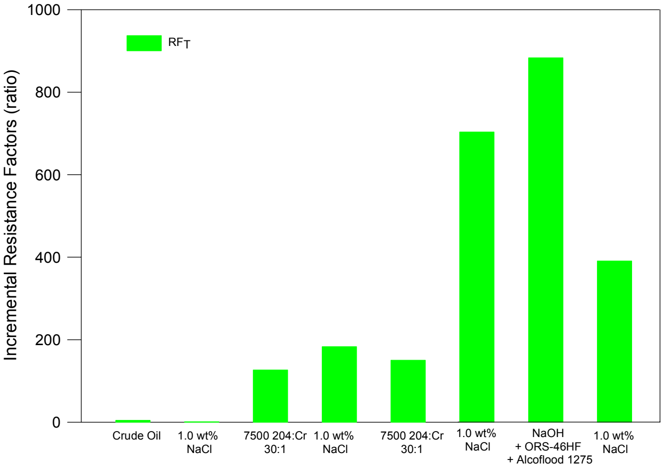

Figure 1 Ending Resistance Factors for a Rigid Polyacrylamide-Chromium Acetate Gel followed by NaOH-ORS-46HF-Alcoflood 1275A Linear Coreflood, RF_T(green) shown

Figure 1 depicts resistance factor changes measured from the injection face to the production face of the core. Residual resistance factors after gel injection and before alkaline-surfactant-polymer solution indicated gel was placed uniformly in the fracture as well as in the core. Residual resistance factors after alkaline-surfactant-polymer injection following gel injection were maintained and of the same order of magnitude as prior to alkaline-surfactant-polymer injection. Polyacrylamide-chromium acetate gels used to plug fractures are stable to subsequent NaOH alkaline-surfactant-polymer solution injection. Permeability changes are summarized in Table 4.

Table 4

Berea Sandstone Physical Parameters

Chromium Acetate – Polyacrylamide Fracture Core Linear Coreflood

	Permeability (md) K_T
NaOH-ORS-46HF-Alcoflood 1275A – 22.8% Porosity	
Pre-Fracture Absolute Permeability to 1.0 wt% NaCl, K_{abs}	630
Pre-Fracture Effective Perm to Oil at Immobile Water, K_{orw}	355
Post-Fracture Effective Perm to Oil at Immobile Water, K_{orw}	33,500
Post-Fracture Effective Perm to Water at Residual Oil, K_{wro}	23,000
Post-Fracture, Post-Gel Sequence, K_{wro}	33
Post-ASP Solution, K_{wro}	60

Elevated Temperature Gel Stability Testing

A series of polyacrylamide-chromium acetate, xanthan gum-chromium acetate, and resorcinol plus formaldehyde gel matrices were mixed and incubated at either 125°F or 175°F with varying pH alkaline-surfactant-polymer solutions to determine if gel systems were stable to alkaline-surfactant-polymer solutions at elevated temperature.

	Polymer Type	Concentration (mg/L)	Crosslinker	Polymer:Crosslink ratio
Polyacrylamide:Aluminum				
	HiVis 350	300 and 500	Watercut 677	1:1
				1:2
				1:3
				1:4
Polyacrylamide Chromium				
	Watercut 204	5,000 and 7,500	Watercut 684	30:1
				35:1
				40:1
				45:1
				50:1
Xanthan Gum:Chromium Gels				
	Flopaam 4800C	4,000 and 6,000	Watercut 684	8:1
				10:1
				12:1
				15:1
				18:1
				20:1

Resorcinol/formaldehyde gels

Resorcinol wt%	Formaldehyde wt%
1.0	0.85
1.0	1.71
2.0	1.71
2.0	3.42
3.0	2.56
3.0	5.12

pH of resorcinol/formaldehyde gel solutions were adjusted to pH 9 with NaOH.

Gels were allowed to sit for 1 to seven days to allow gels to form. Once gels were formed, alkaline-surfactant-polymer solutions were layered over the top of the appropriate gels. Alkaline-surfactant-polymer solutions pH varied from pH 9.2 to 12.9 as reported earlier.[3] Gels were incubated at 125°F and 175°F and visually evaluated at 0, 1, 3, 7 days. Consistent with prior results, gel stability to alkaline-surfactant-polymer solutions was

- Aluminum-polyacrylamide gels were not stable to alkaline-surfactant-polymer solutions with pH values ranging from 9.2 to 12.9.

- Chromium-polyacrylamide gels were stable to alkaline-surfactant-polymer solutions with pH values ranging from 9.2 to 12.9.
- Chromium-xanthan gum gels were stable to alkaline-surfactant-polymer solutions with pH values ranging from 9.2 to 12.9.
- Resorcinol-formaldehyde gels were stable to alkaline-surfactant-polymer solutions with pH values ranging from 9.2 to 12.9.

Elevated Temperature Linear Corefloods

Linear corefloods evaluating the polyacrylamide-chromium acetate gel and the xanthan gum-chromium acetate gel were evaluated at 125°F and 175°F to determine if the gels were stable to an alkaline-surfactant-polymer solution at elevated temperatures. Two pairs of linear core floods were performed to evaluate if the polyacrylamide-chromium acetate gel and the xanthan gum-chromium acetate gel were stable to alkaline-surfactant-polymer solutions at elevated temperatures in core. Figures 2 and 3 depict the resistance factor changes for the polyacrylamide-chromium acetate gel at 125°F and 175°F, respectively. Table 5 summarizes core permeability changes.

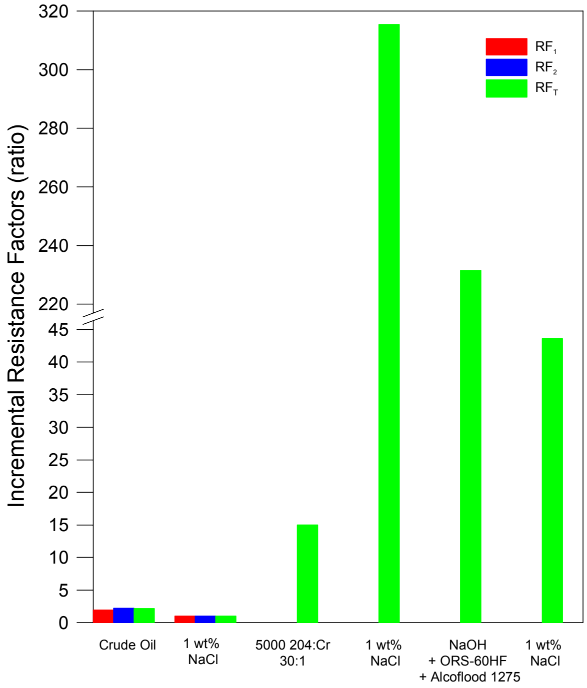

Figure 2 Ending Resistance Factors for Polyacrylamide-Chromium Acetate Gel followed by NaOH-ORS-60HF-Alcoflood 1275A Linear Coreflood at 125°F, from left to right each set of histograms is RF_1(red), RF_2(blue), RF_T(green)

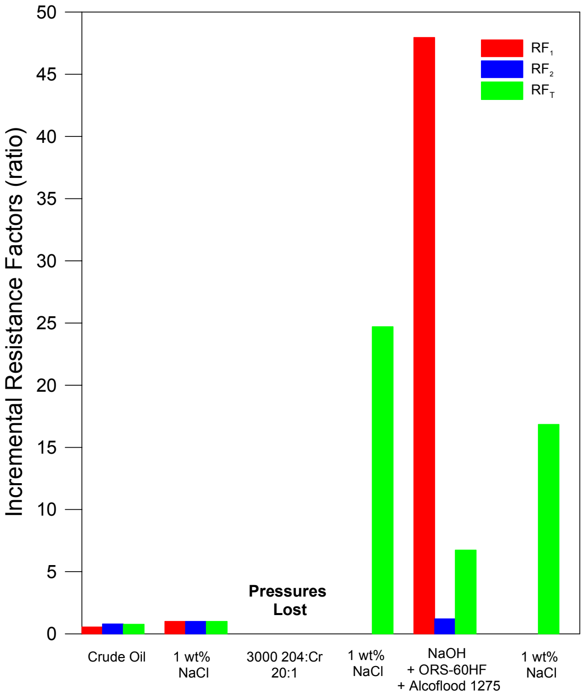

Figure 3 Ending Resistance Factors for Polyacrylamide-Chromium Acetate Gel followed by NaOH-ORS-60HF-Alcoflood 1275A Linear Coreflood at 175°F, from left to right each set of histograms is RF_1(red), RF_2(blue), RF_T(green)

Polyacrylamide-chromium acetate gels were stable to subsequent injection of a 1.0 wt% NaOH plus 0.10 wt% active ORS-60HF plus 1300 mg/L Alcoflood 1275A solution.

Figures 4 and 5 depict the resistance factor changes for the xanthan gum-chromium acetate gel at 125°F and 175°F, respectively. Xanthan gum-chromium acetate gel was stable to subsequent injection of a 1.0 wt% NaOH plus 0.10 wt% active ORS-60HF plus 1300 mg/L Alcoflood 1275A solution at 125°F but not at 175°F. The latter is due primarily to the instability of the gel at the higher temperature. Table 5 summarizes core permeability changes.

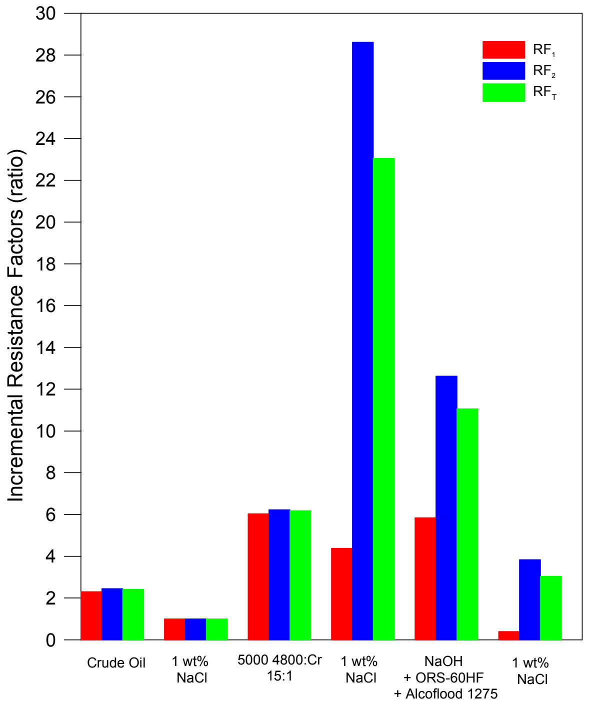

Figure 4 **Ending Resistance Factors for Xanthan Gum-Chromium Acetate Gel followed by NaOH-ORS-60HF-Alcoflood 1275A Linear Coreflood at 125°F, from left to right each set of histograms is RF_1(red), RF_2(blue), RF_T(green)**

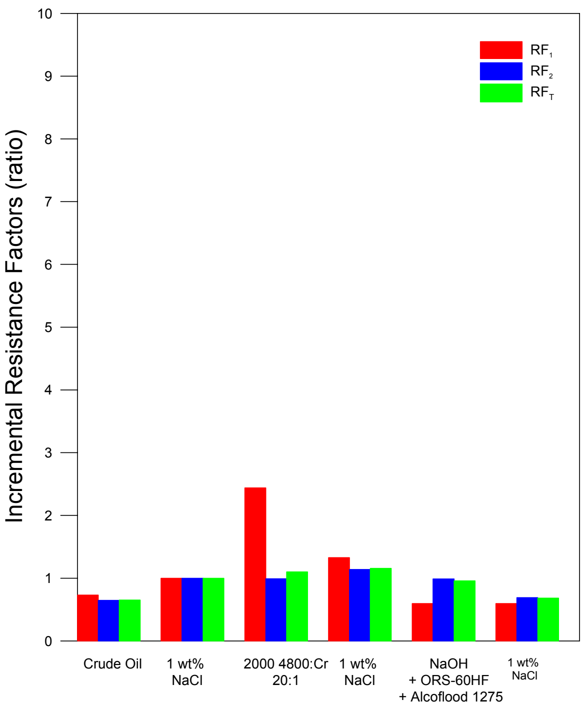

Figure 5 **Ending Resistance Factors for Xanthan Gum-Chromium Acetate Gel followed by NaOH-ORS-60HF-Alcoflood 1275A Linear Coreflood at 175°F, from left to right each set of histograms is RF_1(red), RF_2(blue), RF_T(green)**

Table 5

Berea Sandstone Physical Parameters

Polyacrylamide and Xanthan Gum-Chromium Acetate Gel Linear Corefloods

	----------Permeability (md)----------		
	K_1	K_2	K_T
Polyacrylamide-Chromium Acetate Corefloods			
NaOH-ORS-60HF-Alcoflood 1275A – 23.3% Porosity – 175°F			
Absolute Permeability to 1.0 wt% NaCl, K_{abs}	282	772	555
Effective Perm to Oil at Immobile Water, K_{orw}	547	267	300
Effective Perm to Water at Residual Oil, K_{wro}	17	40	24
Post Gel Sequence, K_{wro}	--	--	<0.1
Post ASP Solution, K_{wro}	--	--	0.3

NaOH-ORS-60HF-Alcoflood 1275A – 23.1% Porosity – 125°F			
Absolute Permeability to 1.0 wt% NaCl, K_{abs}	473	414	424
Effective Perm to Oil at Immobile Water, K_{orw}	646	320	353
Effective Perm to Water at Residual Oil, K_{wro}	13	6	7
Post Gel Sequence, K_{wro}	--	--	0.2
Post ASP Solution, K_{wro}	--	--	0.3
Xanthan Gum-Chromium Acetate Corefloods			
NaOH-ORS-60HF-Alcoflood 1275A – 22.8% Porosity – 175°F			
Absolute Permeability to 1.0 wt% NaCl, K_{abs}	346	280	291
Effective Perm to Oil at Immobile Water, K_{orw}	528	262	288
Effective Perm to Water at Residual Oil, K_{wro}	15	4	5
Post Gel Sequence, K_{wro}	8	2	3
Post ASP Solution, K_{wro}	18	5	6
NaOH-ORS-60HF-Alcoflood 1275A – 22.6% Porosity – 125°F			
Absolute Permeability to 1.0 wt% NaCl, K_{abs}	514	499	502
Effective Perm to Oil at Immobile Water, K_{orw}	535	535	535
Effective Perm to Water at Residual Oil, K_{wro}	32	21	22
Post Gel Sequence, K_{wro}	8	2	3
Post ASP Solution, K_{wro}	32	6	8

Gel sequence and alkaline-surfactant-polymer injection recovered additional oil. Table 6 summarizes oil production with each step.

Table 6

Oil Recovery of Polyacrylamide and Xanthan Gum-Chromium Acetate Gel Corefloods

	-------Cumulative Oil Recovery, % OOIP---------	
Polyacrylamide-Chromium Acetate Corefloods		
Injected Solution	125°F-Coreflood	175°F-Coreflood
1.0 wt% NaCl - Waterflood	52.8	63.7
Gel Sequence and NaCl flush	75.2	74.0
ASP Solution and NaCl flush	95.6	98.4
	-------Incremental Oil Recovery, % OOIP---------	
Gel Incremental Oil Recovery	22.4	10.3
Gel+ASP Incremental Recovery	20.4	24.4
Xanthan Gum-Chromium Acetate Corefloods		
Injected Solution	125°F-Coreflood	175°F-Coreflood
1.0 wt% NaCl - Waterflood	51.7	61.2
Gel Sequence and NaCl flush	69.4	68.4
ASP Solution and NaCl flush	92.4	92.2
	-------Incremental Oil Recovery, % OOIP---------	
Gel Incremental Oil Recovery	17.7	7.2
Gel+ASP Incremental Recovery	23.0	23.8

Significant incremental oil was produced by gel injection and subsequent alkaline-surfactant-polymer solutions.

Elevated Temperature Chromium Acetate-Polyacrylamide Gel Dual Stacked Core, Common Well Bore Stacked Radial Corefloods

A dual stacked core pair with a common well bore coreflood evaluated the stability of a chromium acetate-polyacrylamide gel to subsequent alkaline-surfactant-polymer injection at 175°F. In this case, cross flow was possible. Injected gel mixture was 3000 mg/L Watercut 204 plus 150 mg/L Watercut 684 as Cr^{+3}. Polymer and chromium ion concentrations were lower than previous reported 72°F coreflood[2] to permit gel to be injected prior to developing rigidity. Injected alkaline-surfactant-polymer solution was 1.0 wt% NaOH plus 0.06 wt% active ORS-60HF plus 1300 mg/L Alcoflood 1275A. Crude oil was the 19.4° API gravity crude oil. Figures 6 and 7 depict resistance factor changes for the both core. Chromium acetate-polyacrylamide gel reduced the permeability of each core with the high permeability core permeability reduction being slightly greater during and after gel injection. Permeability changes were maintained after alkaline-surfactant-polymer injection but not to the same degree as previously reported possibly due to injection of a more fluid gel and gel syneresis. Permeability changes for dual, stacked core chromium acetate-polyacrylamide coreflood are summarized in Table 7.

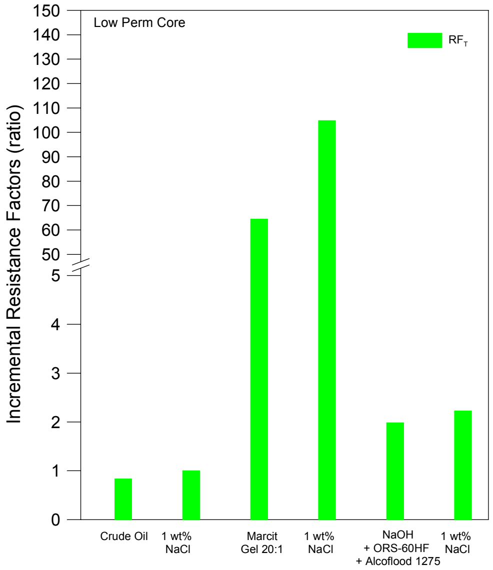

Figure 6 Low Permeability Core, Ending Resistance Factors for the Rigid Chromium Acetate-Polyacrylamide Gel followed by NaOH-ORS-60HF-Alcoflood 1275A, from left to right each set of histograms is RF_T(green)

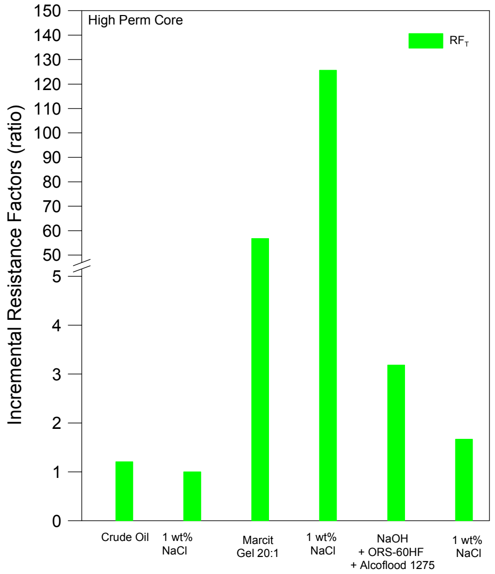

Figure 7 High Permeability Core, Ending Resistance Factors for the Rigid Chromium Acetate-Polyacrylamide Gel followed by NaOH-ORS-60HF-Alcoflood 1275A, from left to right each set of histograms is RF_T(green)

Table 7

Berea Sandstone Physical Parameters – Chromium Acetate-Polyacrylamide Dual Stacked, Same Well Bore 175^{o}F Radial Coreflood

	Permeability (md)		
	K_1	K_2	K_T
NaOH-ORS-60HF-Alcoflood 1275A			
High Permeability Core – 23.0% Porosity			
Absolute Permeability to 1.0 wt% NaCl, K_{abs}	535	458	508
Effective Perm to Oil at Immobile Water, K_{orw}	105	90	90
Effective Perm to Oil at Immobile Water, K_{orw} (after stacking core)	---	---	108
Effective Perm to Water at Residual Oil, K_{wro}	---	---	3.7
Post Gel Sequence, K_{wro}	---	---	0.03
Post ASP Solution, K_{wro}	---	---	2.2
Low Permeability Core – 18.5% Porosity			
Absolute Permeability to 1.0 wt% NaCl, K_{abs}	45	82	52
Effective Perm to Oil at Immobile Water, K_{orw}	28	18	23
Effective Perm to Oil at Immobile Water, K_{orw} (after stacking core)	---	---	26
Effective Perm to Water at Residual Oil, K_{wro}	---	---	0.6
Post Gel Sequence, K_{wro}	---	---	0.01
Post ASP Solution, K_{wro}	---	---	0.3

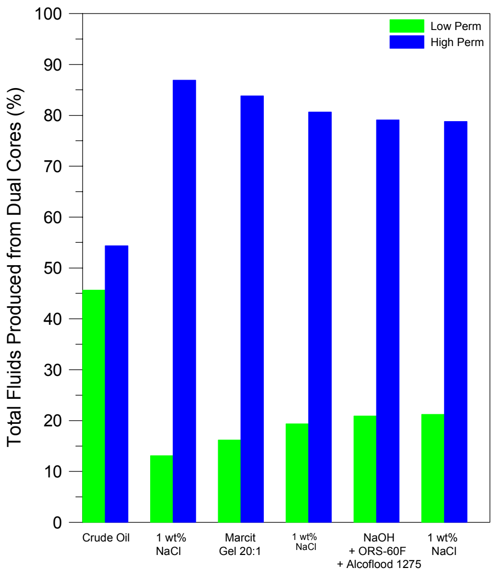

Figure 8 Flow Distribution between High and Low Permeability Cores, Dual Stacked Radial Coreflood, Chromium Acetate -Polyacrylamide Gel, green is low permeability and blue is high permeability

Change in flow distribution due to chromium acetate-polyacrylamide gel injection into the stacked radial core configuration is shown in Figure 8. Flow distribution was 87% flow through the high permeability core during initial waterflood. Flow distribution was reduced to 80% through the high permeability core during the water flush subsequent to gel placement, indicating gel was diverting injected water from the high permeability core into the low permeability core. Injected alkaline-surfactant-polymer solution did not alter the flow distribution.

Oil recoveries from the chromium acetate-polyacrylamide gel stacked radial flood are summarized in Table 8. Incremental oil was produced during gel injection from each core. Alkaline-surfactant-polymer injection produced a significant volume of incremental oil from both core.

Table 8

Oil Recovery of Chromium Acetate -- Polyacrylamide Gel
Dual Stacked, Same Well Bore 175°F Radial Coreflood

	-------Cumulative Oil Recovery, % OOIP---------	
Injected Solution	High K - Core	Low K - Core
1.0 wt% NaCl - Waterflood	47.5	30.4
Gel Sequence and NaCl flush	59.1	38.0
ASP Solution and NaCl flush	93.0	52.1
	-------Incremental Oil Recovery, % OOIP---------	
Gel Incremental Oil Recovery	11.6	6.6
Gel+ASP Incremental Recovery	33.9	14.1

Numerical Simulation of a Crosslink-Alkaline-Surfactant-Polymer Flood

A Minnelusa reservoir with an “A” sand and a “B” sand with common production and injection wells was simulated to demonstrate improvement of oil recovery after gel treatment followed by an alkaline-surfactant-polymer flood. A and B sands are separated by a shale layer. GCOMP numerical simulation software was used.[4] GCOMP is a black oil numerical simulation package with a chemical flood option.

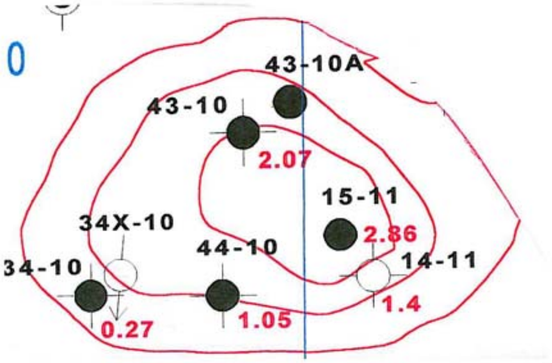

Figure 9 Minnelusa Field Well Orientation

The flood consists of one injection well (34X-10) and two production wells (43-10A and 15-11). Wells 44-10, 14-11, 43-10, and 34-10 were either dry holes or were lost prior to contemplating alkaline-surfactant-polymer injection. Figure 9 depicts the well orientation.

Reservoir and Model Definition

A 20 by 14 grid model consisting of seven layers with the top two layers A sand and bottom five layers presenting the B sand was defined. Table 9 lists individual layer parameters.

Table 9

Numerical Simulation Layer Parameters

	Layer	Pay (ft)		Porosity (%)	KXY (md)	KZ (md)	Pore Volume (bbls)
A Sand	1	4.3		20.2	224	184	1,286,600
	2	10.5		19.9	381	312	3,136,523
	Sum	14.8	Average	20.0	302	248	4,423,123
B Sand	4	1.3		21.0	506	415	18,469
	5	0.5		18.5	79	65	4,995
	6	9.4		17.7	807	662	2,259,435
	7	6.5		12.1	565	463	909,069
	Sum	17.7	Average	17.3	626	512	3,191,968

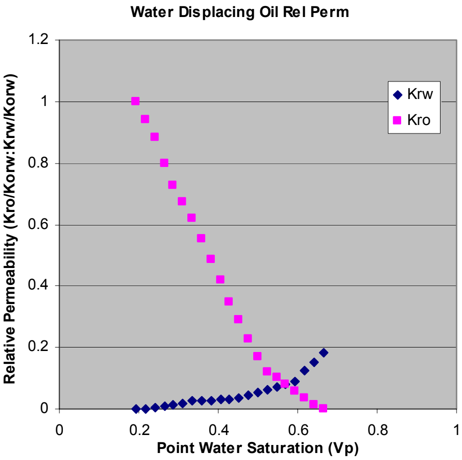

Figure 10 Minnelusa Oil-Water Relative Permeability Curve

History Match - Model Validation

A production waterflood history match was performed by fixing the oil rate from each well and allowing water rate and oil cut to vary. History match was from 1961 to 2003. Figure 11 shows oil rate, water rate, and oil cut match for the wells. Injection matched historical values exactly.

Initial oil saturation was 0.805 V_p and water flood residual oil saturation was 0.335 V_p. Figure 10 depicts the water displacing oil relative permeability curve. Initial reservoir pressure was 2685 psi. Reservoir temperature was 133°F. The Minnelusa Field produces a dead crude oil with an API gravity of 21.5° with a viscosity of 29 cp at initial reservoir pressure and temperature. Formation volume factor was 1.02. Bubble point was 175 psi. Fluid and rock compressibilities used in the model are water 2.95E-06 psi^{-1}, crude oil 5.79E-06 psi^{-1}, and rock 2.7E-05 psi^{-1}. Transmissivity between the layers was equal to 82% of the horizontal transmissivity.

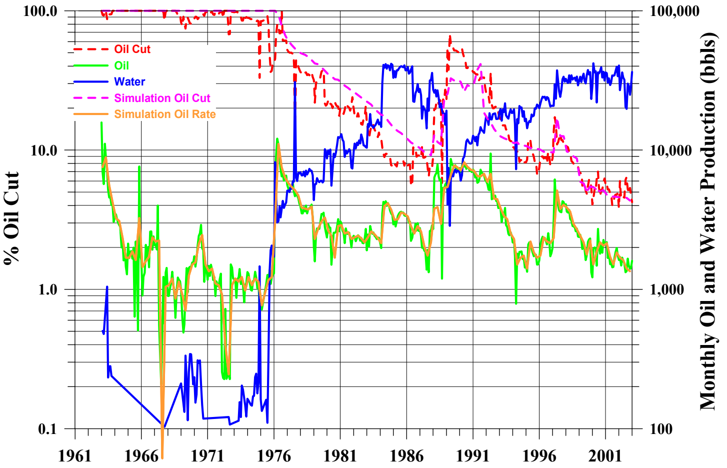

Figure 11 History Match –Primary/Waterflood Production

Coreflood History Match - Chemical Model Validation

An alkaline-surfactant-polymer radial coreflood was history matched to calibrate model chemical option. Coreflood used reservoir crude oil, produced water, and reservoir core. Chemical system used was 1.00 wt% NaOH plus 0.1 wt% ORS-46HF plus 1300 mg/L Alcoflood 1275A. Linear coreflood data was used to develop adsorption isotherms and polymer rheology data. Interfacial tension values used in the model are from laboratory measurements.

Radial coreflood model consisted of a 5 by 1 radial grid system with 2 layers. Initial oil saturation was 0.805 V_p. Initial reservoir pressure was 2685 psi. PVT characteristics were such that the viscosity of the crude oil was 28 cp at 133^o F at 2685 psi. No water-oil or gas-oil contacts were present. PVT characteristics and relative permeability curves from the field history match were used in the corefloods match.

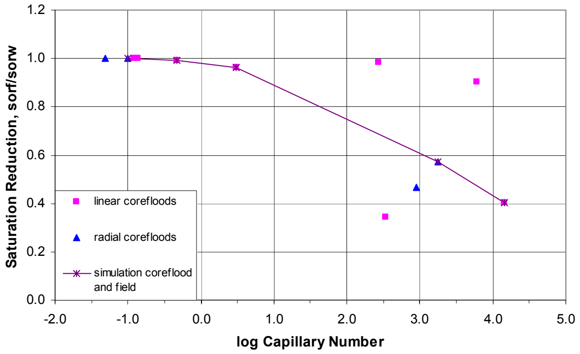

Figure 12 **Oil Saturation Reduction versus log Capillary Number**

Coreflood history match was achieved by changing permeability and capillary number de-saturation curve. Final permeability distribution was 14 md for both layers. This compares to 13.6 and 16.3 md for the effective permeability to oil and effective permeability to water, respectively. Figure 12 shows the capillary de-saturation curve required to match the coreflood. Note, the capillary number - de-saturation correlation matched coreflood values during waterflood. As capillary number increased due to chemical injection, linear coreflood data facilitated a match better than radial coreflood data.

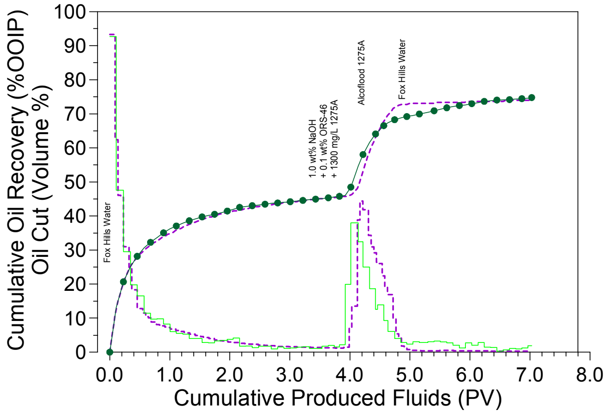

Figure 13 Oil Cut and Cumulative Oil Recovery Radial Coreflood History Match

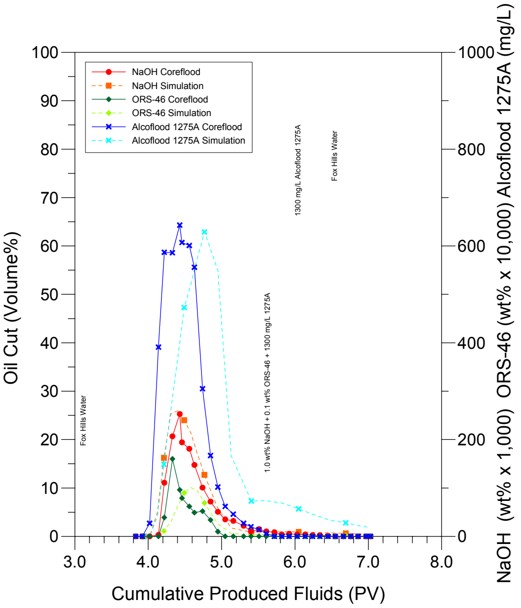

Figure 14 Produced Chemical Radial Coreflood History Match

Figures 13 and 14 show oil recovery and oil cut history match, and produced chemical match for the alkaline-surfactant-polymer radial coreflood. Both the waterflood and chemical flood oil recoveries are duplicated by the numerical simulation indicating the relative permeability and capillary number calculation accurately depict the waterflood and the alkaline-surfactant-polymer flood for the Minnelusa oil, water, and rock system. Produced chemicals were similarly matched.

Alkaline-Polymer and Alkaline-Surfactant-Polymer Forecasts

Five forecasts were made:

1. Waterflood through 2020
2. Crosslink B Sand in 2003 followed by water through 2020
3. No Crosslink, ASP Flood:
   B Sand - 0.262 V_p ASP followed by 0.278 V_p polymer drive followed by water to 2020 (0.972 V_p)
   A Sand - 0.024 V_p ASP followed by 0.076 V_p polymer drive followed by water to 2020 (0.049 V_p)
4. Crosslink B Sand and inject chemical over the same time as case 3:
   B Sand - 0.091 V_p ASP followed by 0.110 V_p polymer drive followed by water to 2020 (0.885 V_p)
   A Sand - 0.036 V_p ASP followed by 0.098 V_p polymer drive followed by water to 2020 (0.087 V_p)
5. Crosslink B Sand and inject chemical until approximately 0.25 Vp of ASP solution has been injected into the B Sand:
   B Sand - 0.239 V_p ASP followed by 0.152 V_p polymer drive followed by water to 2020 (0.315 V_p)
   A Sand - 0.124 V_p ASP followed by 0.126 V_p polymer drive followed by water to 2020 (0.027 V_p)

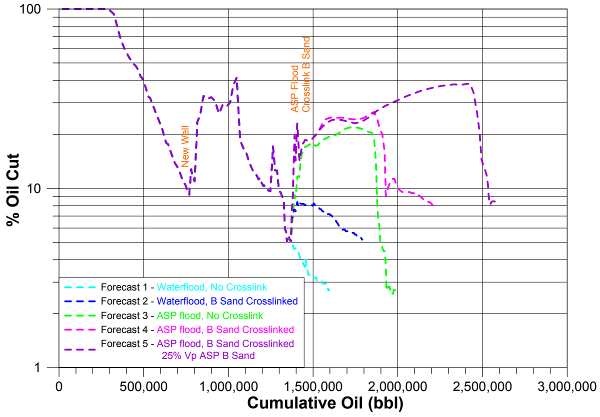

Figure 15 Oil Cut versus Cumulative Oil Produced for the Five Forecast Cases

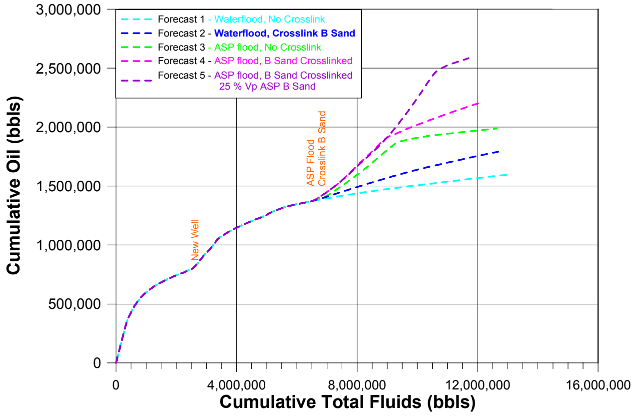

Figure 16 Cumulative Oil Produced versus Cumulative Total Fluids for the Five Forecast Cases

Figure 15 depicts the oil cut as a function of cumulative oil production and Figure 16 depicts cumulative oil as function of cumulative total fluids produced. Crosslinking of the B Sand was simulated by decreasing the X, Y, and Z transmissivity of the B Sand to 20% of the original value, corresponding to a resistance factor of 5. Note in Figure the volume of fluids produced and, therefore, injected decreases when either the B Sand is crosslinked or viscous ASP solution is injected. Total fluid produced volume and, therefore, injection volume decreased by up to 2,800,000 bbls. Table 10 summarizes incremental oil produced.

Table 10

Waterflood and Alkaline-Surfactant-Polymer Flood Forecast Incremental Oil Production

	---------Incremental Oil Production (bbls) ---------	
	Over Waterflood	Over no Crosslink ASP Flood
B Sand Crosslink Waterflood	196,144	-------
No Crosslink ASP Flood	392,656	-------
B Sand Crosslink ASP Flood	619,988	227,332
B Sand Crosslink 25% Vp ASP Flood	989,090	596,436

Conclusions

1. Chromium-polyacrylamide gels are stable to injection of an alkaline-surfactant-polymer solution from 72°F to 175°F.

2. Injection of a gel sequence prior to an alkaline-surfactant-polymer solution will divert injected fluid into lower permeability core, resulting in higher oil recoveries.

3. Gels used to seal fractures are stable to subsequent alkaline-surfactant-polymer solution injection, if gels are stable to alkaline-surfactant-polymer solutions in other applications.

4. Numerical simulation indicates placement of a gel into a higher permeability section of a reservoir will improve waterflood recovery and alkaline-surfactant-polymer flood oil recovery compared to the same injection fluid without a prior gel treatment.

References

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1. Miller, Bernie, Pitts, Malcolm J., Dowling, Phillip, and Wilson, Dan: "Single Well Alkaline-Surfactant Injectivity Improvement Test in the Big Sinking Field," SPE 89384, presented at the 2004 SPE/DOE Fourteenth Symposium on Improved Oil Recovery held in Tulsa, Oklahoma, U.S.A., 17–21 April 2004.

2. Pitts, M., Qi, J., Wilson, D., Stewart, D. and Jones, B.: Semi-annual Technical Progress Report, Coupling the Alkaline-Surfactant-Polymer Technology and the Gelation Technology to Maximize Oil Production, September 30, 2004 to April 1, 2005, submitted to the Department of Energy, Award Number De-FC26-03NT15411.

3. Pitts, M., Qi, J., and Wilson, D.: Semi-annual Technical Progress Report, Coupling the Alkaline-Surfactant-Polymer Technology and the Gelation Technology to Maximize Oil Production, October 1, 2003 to April 1, 2004, submitted to the Department of Energy, Award Number De-FC26-03NT15411.

4. PHH Engineering, Calgary, Alberta.