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Technical Progress Report
Final Report
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Injectivity Improvement of Low Permeability Reservoirs
Big Sinking Field, Lee County, Kentucky

February 2004

SURTEK

Table of Contents

Executive Summary

The injectivity improvement study in the Big Sinking Field, Lee County, Kentucky demonstrated that a low interfacial tension solution can be used to alter the relative permeability characteristics near an injection well and increase water injection rates. A laboratory program consisting of interfacial tension, phase behavior, and linear and radial corefloods designed alkaline-surfactant polymer solutions demonstrating potential to increase injectivity. A core was taken for the laboratory program and to provide a new well bore for the field trial. Injection of a sodium hydroxide (alkali) plus ORS-164HF (surfactant) solution increased water injectivity by 220%. A paper will be presented at the SPE/DOE Fourteenth Symposium in April 2004 to continue technology transfer.

Results and Discussion

A. **Objectives of Project**

To demonstrate that a low interfacial tension alkaline-surfactant solution can increase injectivity in the Big Sinking Field using laboratory and field evaluations.

B. **Laboratory Evaluations**

1. **Fluid Analysis**

Oil and water samples received were analyzed. The oil is a 39 API gravity oil with a dead oil viscosity of 7.3 cp at 68ºF. Produced and fresh water analyses are listed in the following table. Zacharia Lake water will be used to dissolve chemicals in the laboratory study. Chemical dissolution water was switched to City Water for the field injectivity. As a result, softening was required and initial injection of alkali and surfactant reduced injectivity due to alkaline precipitates. Injectivity was restored with acid.

Ion	Townsend # 5 Produced Water	Zacharia Lake Water	City Water
	Ion Concentration mg/L		
Calcium	2,250	4	65
Magnesium	480	2	35
Barium	25	<5	---
Strontium	160	<5	---
Sodium	8,300	14	---
Potassium	60	<5	---
Iron	10	<5	---
Chloride	18,257	12	---
Sulfate	3	7	---
Carbonate	0	0	---
Bicarbonate	187	30	---
Total Dissolved Solids	33,573	52	540
pH	7.13	7.43	---

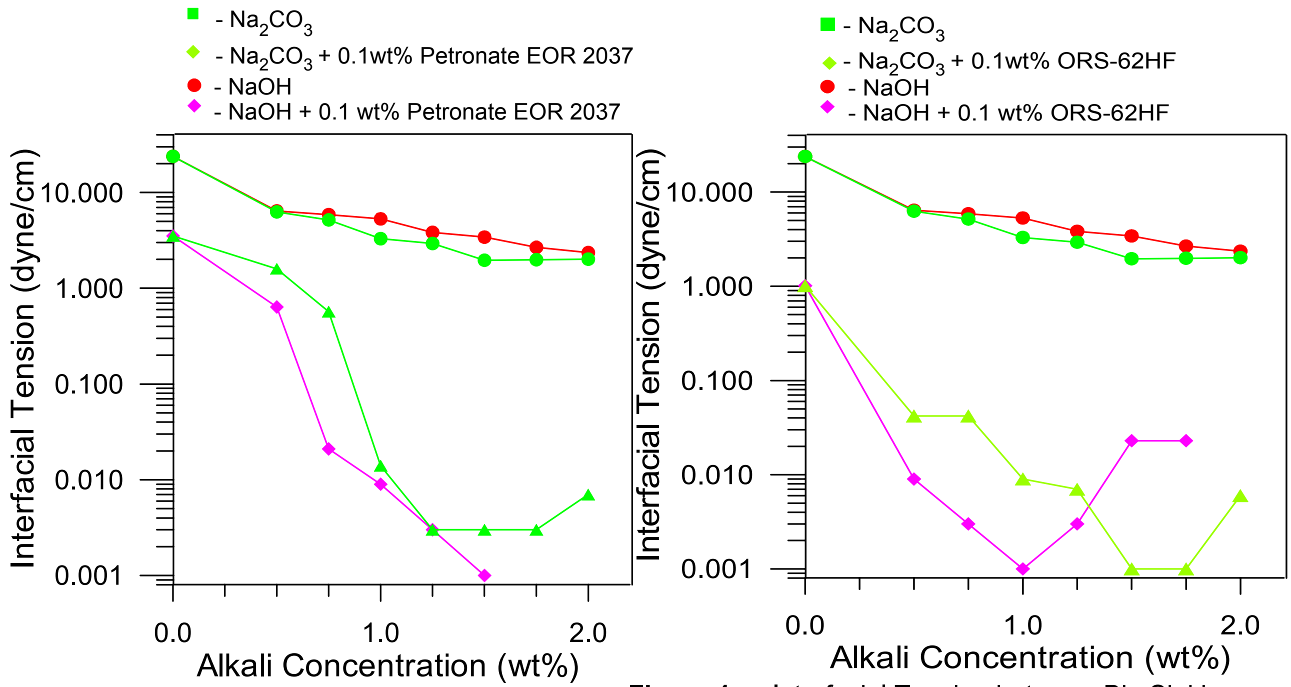


Figure 1 Interfacial Tension between Big Sinking Crude Oil and Aqueous Alkali and Alkali Surfactant

2. **Interfacial Tension and Phase Behavior Screening**
   Interfacial tension and phase behavior screening were performed by blending two alkaline agents (sodium carbonate, Na_2CO_3 and sodium hydroxide, NaOH) with twenty two surfactants. Seven alkali concentration ranging from 0.5 to 2.0 wt% were tested with 0.1 wt% active surfactant. An additional twelve surfactants were tested with only three alkali concentrations.

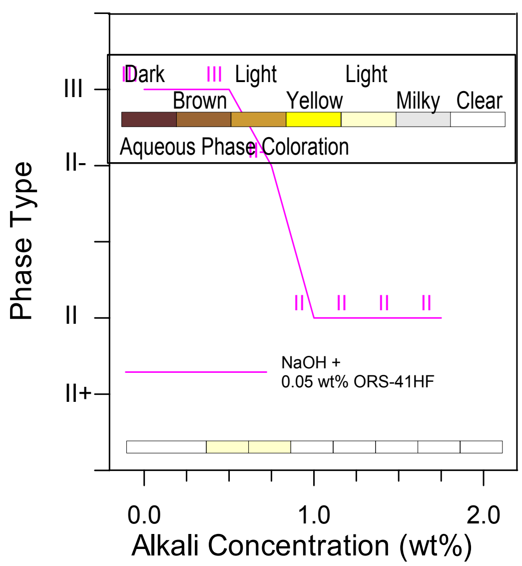


Figure 2 Phase Behavior of Alkaline plus Surfactant Solution with Big Sinking Crude Oil

Interfacial tension values were reduced to 0.001 dyne/cm with eleven of the surfactants tested with either NaOH or Na_2CO_3. Interfacial tension values of 0.001 dyne/cm represent an interfacial tension reduction of 23,680 fold and, therefore, a capillary number increase of 23,680. Eighteen of the surfactants reduced the interfacial tension by at least 5,000 fold when blended with alkali. Based on capillary number theory, sufficient interfacial tension reduction was achieved to expect a reduction of the oil saturation and to change the effective water permeability of the Big Sinking rock.

Two surfactants (ORS 62 HF and Petronate EOR 2037) interfacial tension versus alkali concentration curves are shown in Figure 1. Type III and type II- phase types were observed with the majority of alkali and surfactant solutions with low interfacial tension values, type III and type II- being considered optimum for oil saturation reduction. Phase behavior change with ORS-41HF and NaOH is shown in the Figure 2. Phase type nomenclature is designated according to Nelson and Pope.[1]

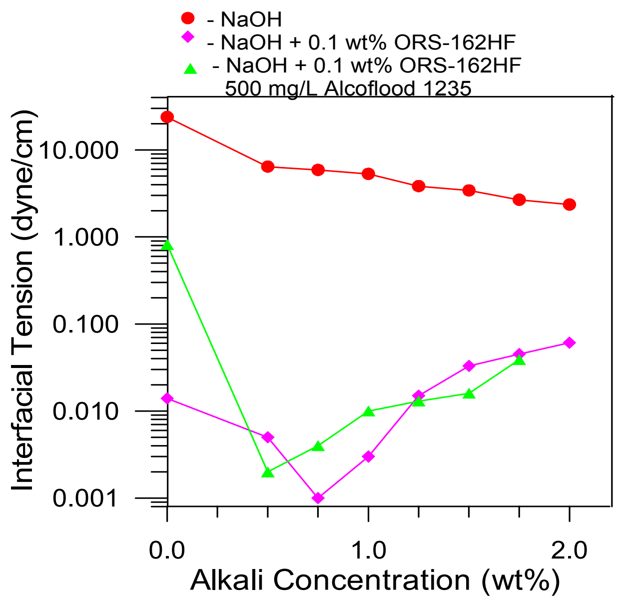


Figure 3 Effect of Polyacrylamide Polymer on the Interfacial Tension between Big Sinking Crude Oil and Aqueous Alkali plus Surfactant

3. Effect of Polyacrylamide Polymer on Solution Characteristics

Polyacrylamide polymer was added to alkaline-surfactant solutions with low interfacial tension values and favorable phase behavior, and the interfacial tension and phase behavior was measured. Addition of polymer to the solution resulted in a minimal change of interfacial tension and phase behavior characteristics of most alkaline-surfactant solutions. The effect of polymer on a NaOH plus ORS-162HF solution is shown in Figure 3.

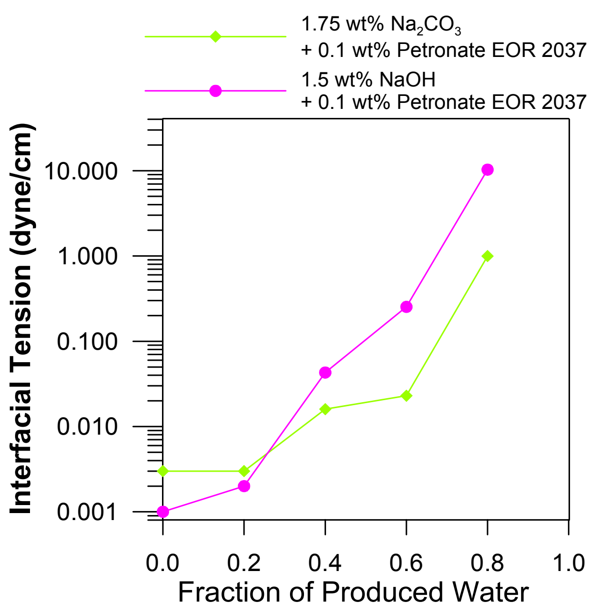


Figure 4 Effect of Produced Water Dilution on the Interfacial Tension Between Big Sinking Crude Oil and Aqueous Alkali plus Surfactant

4. Produced Water Dilution Effect on Solution Characteristics

To help determine which solution's low interfacial tension and phase behavior characteristics will persist when injected into the Big Sinking reservoir, the alkaline-surfactant solutions were diluted with produced water and the interfacial tension and phase behavior measured. Alkaline-surfactant solutions were diluted with 20, 40, 60, and 80% produced water. Low interfacial tension values were generally better maintained with Na_2CO_3 as opposed to NaOH. Interfacial tension values remained lower at greater dilution with higher alkali concentration. A typical interfacial tension curve with produced water dilution is shown in Figure 4.

5. Injectivity Improvement Linear Corefloods

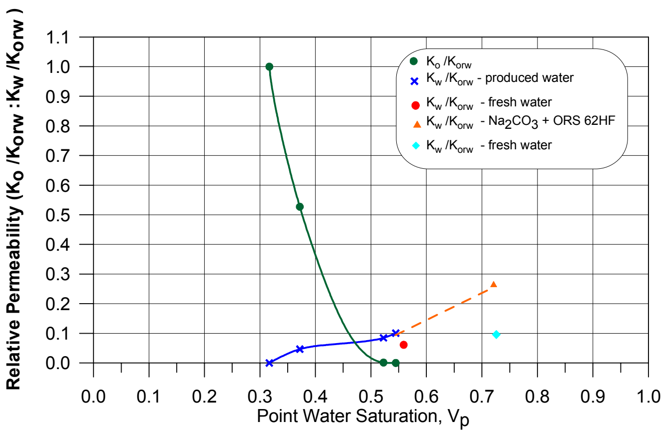


Figure 5 Big Sinking Water-Oil Relative Permeability, Dark Green is Effective Permeability to Produced Water, Blue is Effective Permeability to Oil, Red Dot is Effective Permeability to Fresh Water before Alkali plus Surfactant, Orange Dashed Line and Triangle is the Effective Permeability to Alkali plus Surfactant, Powder Blue Dot is Effective Permeability to Water after Alkali plus Surfactant

a. **Relative Permeability Characteristics** - Figure 5 shows the relative permeability using produced water as the displacing phase. Big sinking core displayed water-wet characteristics. Mobility ratio for water displacing oil is favorable, averaging 0.6. Initial oil saturation averaged 0.69 Vp. Produced water injection reduced the average oil saturation to 0.41 Vp, recovering 41% OOIP.

When fresh water was injected after the produced water, the relative permeability characteristics changed. Average effective permeability to water at residual oil decreased to 2.6 md from 4.0 md. As a result, mobility ratio becomes more favorable at 0.4. However, the decline in effective water permeability means that water injectivity decreased by 35%. Fresh water injection produced an additional 0.01 Vp of oil bringing the total oil recovery to 42% OOIP.

b. **Alkaline-Surfactant Injectivity Improvement** - Two alkaline-surfactant solutions were injected into two Big Sinking linear cores from the Second Sand followed by fresh water to reduce the residual oil saturation and increase the effective permeability to water. The data are summarized in Table 1. Figure 5 depicts the changes in effective water permeability for a fresh water and a 1.5% Na_2CO_3 + 0.1% ORS-62HF solution. Effective water permeability decreases when fresh water is injected, red dot, indicating a sensitivity of the Second Sand to lower total dissolved solids water. When the alkaline plus surfactant solution, the effective water permeability increases to double the effective water permeability to fresh water, orange triangle and dashed line in Figure 5. Subsequent fresh water injection results in a decreased the effective permeability to water for the Na_2CO_3 coreflood but not the NaOH coreflood, see Table 1.

Table 1
Oil Saturation, Effective Water Permeability and Percent Effective Water Permeability Change Summary, Big Sinking Linear Corefloods

Injected Solutions	Oil Saturation Vp	Effective Water Permeability md	percent increase over fresh wtr
Flood 1			
produced water	0.45	3.7	-----
fresh water	0.44	2.7	-----
1.5% Na_2CO_3 + 0.1% ORS-62HF*	0.28	11.5	425%
fresh water flush	0.27	4.2	155%
Flood 2			
produced water	0.38	4.3	----
fresh water	0.37	2.5	----
0.75% NaOH + 0.2% AX-210-6*	0.33	7.8	310%
fresh water flush	0.30	8.1	325%

* Surfactant concentrations are active concentrations

Injectivity was improved with both alkaline-surfactant solutions an average of 370%. Injectivity improvement was maintained with subsequent fresh water injection at an average 240%. The hydroxide solution maintained the injectivity improvement perhaps due to the higher pH reacting with the clays as described by Sydansk for KOH solutions.[2]

c. **Polymer Addition to Alkaline-Surfactant Solutions** - Because inclusion of polymer into the alkaline-surfactant solution results in a significant decrease in oil saturation, two manufacturer's polymers were added to the alkaline-surfactant solutions and injected into the Big Sinking core. Both Ciba Speciality Chemicals' Alcoflood 1235 and SNF Floerger's Flopaam 3230 injected into and flowed through the Big Sinking core. The oil saturation change and effective water permeability changes are listed in Table 2.

Table 2
Effect of Polymer on Effective Permeability Changes in Big Sinking Core
After Injection of Alkali plus Surfactant

Injected Solutions	Oil Saturation Vp	Effective Water Permeability md	percent increase over initial
Flood 1			
fresh water	0.44	2.7	----
1.5% Na_2CO_3 + 0.1% ORS-62HF	0.28	11.5	425%
fresh water flush	0.27	4.2	155%
1.5% Na_2CO_3 + 0.1% ORS-62HF + 950 mg/L Flopaam 3230S	0.17	—	----
fresh water flush	0.17	3.3	120%
produced water flush	0.17	5.2	190%
Flood 2			
fresh water	0.37	2.5	----
0.75% NaOH + 0.2% AX-210-6	0.33	7.8	310%
fresh water flush	0.30	8.1	325%
0.75% NaOH + 0.2% AX-210-6 + 950 mg/L Alcoflood 1235	0.16	----	----
fresh water flush	0.13	6.0	180%
produced water flush	0.13	10.9	435%

* Surfactant concentrations are active concentrations

Both polymers reduced the effective permeability to water as expected. However, the injectivity to water was still greater than it was before the core was treated with the alkaline-surfactant solutions. In both cores, about 75% of the effective permeability to water was maintained suggesting little difference between the permeability reduction characteristics of the two polymers. Injection of produced water after the fresh water flush increased injectivity in both cores, suggesting the effective permeability loss is reversible.

Injection of additional polymer concentrations to calculate amount required to give an alkaline-surfactant-polymer solution a mobility ratio of one or less indicates that the concentration is dictated by the adsorption of polymer onto the rock. A concentration of 550 mg/L is necessary to give the displacing solution a unit mobility ratio.

Total oil recovery after all injection averaged 0.59 Vp or 86% OOIP. Final oil saturation averaged 0.10 Vp. This suggests that injection of an alkaline-surfactant-polymer solution into the Big Sinking reservoir has the potential to produce incremental oil in addition to injectivity improvement.

6. **Injectivity Radial Coreflood**

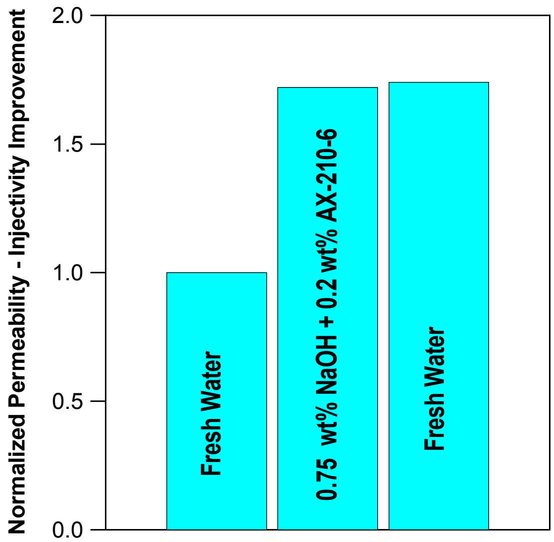


Figure 6 Normalized Effective Fresh Water Permeability Improvement by Alkali plus Surfactant Injection, Effective Water Permeability is Normalized to the End of the Waterflood

Vertical wells flow characteristics are better represented with radial corefloods than with linear corefloods. A radial injectivity improvement coreflood was performed to simulate the increase in injectivity potential Fresh water was injected, 7 Vp, to residual oil saturation followed by 4.1 Vp of 0.75 wt% NaOH plus 0.2 wt% AX-210-6. Fresh water, 4.3 Vp, was subsequently injected and ultimately produced water to determine injectivity changes. The injectivity change is shown in the adjacent figure. Injectivity improved 173% during alkaline-surfactant injection as well as for the following fresh water injection. Produced water injectivity was an improved by 285%. This compares with a linear coreflood injectivity improvement of 310% and 325% with the same alkaline-surfactant solution and fresh water flush.

Mobility ratio for water displacing crude oil was 1.1. During alkali-surfactant and fresh water injection, the mobility ratio for injected phase displacement of oil was 1.9 and during the final produced water injection the mobility ratio increased to 3.1. Mobility ratio change is a result of an increase of effective water permeability. Oil saturation decreased from an initial oil saturation of 0.729 Vp with fresh injection to 0.314 Vp. The final oil saturation was 0.220 Vp after chemical injection and fresh water flush. Total oil recovery was 69.8% OOIP. Therefore, injection of an alkaline-surfactant solution has changed the relative permeability characteristics of the Big Sinking core.

7. **Alkaline-Surfactant-Polymer Radial Corefloods**

Five radial corefloods were performed to determine the effect on injectivity of polymer addition to the alkaline-surfactant solution and to determine the oil recovery potential of an alkaline-surfactant-polymer injection sequence. The coreflood sequence was to inject approximately 3.3 Vp fresh water followed by 0.3 Vp alkaline-surfactant-polymer followed by 0.3 Vp polymer solution and ultimately fresh water, 3.4 Vp, to flush chemicals from the core for mass balance. Oil recovery, final oil saturation, peak oil cut due to chemical injection, and change in effective water permeability are listed in Table 3.

Table 3
Radial Coreflood Oil Recovery and Injectivity Change

Injected Solutions	Oil Recovery % OOIP Waterflood	Oil Recovery % OOIP ASP flood	Peak Oil Cut %	Final Oil Saturation Vp	Change of Effective Water Permeability** %
0.75% NaOH + 0.2% AX-210-6 + 550 mg/L 3230S*	50.0	12.1	21.4	0.264	-26.2%
1.5% Na_2CO_3 + 0.1% EOR 2037 + 550 mg/L 3230S*	54.8	7.1	4.9	0.232	-30.4%
1.25% Na_2CO_3 + 0.1% AX 131-3 + 550 mg/L 3230S*	53.7	15.1	16.7	0.218	no data
1.5% Na_2CO_3 + 0.1% ORS-62HF + 550 mg/L 3230S*	55.0	6.1	6.7	0.247	-94.5%
0.5% NaOH + 0.1% ORS-162HF + 550 mg/L 3230S*	56.4	9.1	13.2	0.209	+21.7%

* Surfactant concentrations are active concentrations, 3230S is Flopaam 3230S
** fresh water after chemical relative to fresh water before chemical

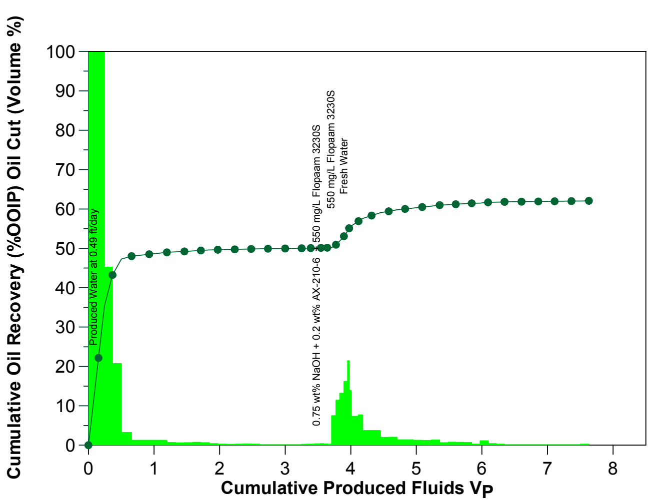


Figure 7 Waterflood and Chemical Flood Oil Recovery, dotted dark green line is cumulative oil recovery, lime green histogram is oil cut, chemical flood begins at approximately 3.5 Vp.

Average initial oil saturation was 0.688 Vp and average waterflood residual oil saturation was 0.316 Vp. Average waterflood oil recovery was 54.0% OOIP or 0.371 Vp. Average chemical flood oil recovery was 12.0% OOIP or 8.2 Vp. Figure 7 shows the oil cut and oil recovery performance for the NaOH plus AX-210-6 plus 550 mg/L Flopaam 3230S radial coreflood.

Mobility ratio average for water displacing oil was 0.6. The mobility ratio during chemical injection averaged 0.2 so chemical flood mobility was sufficient at the injected polymer concentration.

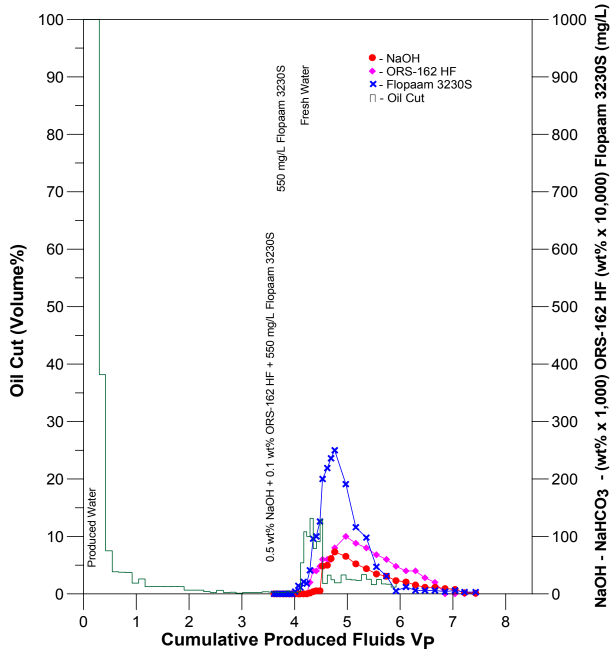


Figure 8 Produced Chemical Concentration and Oil Cut as a Function of Cumulative Total Fluids Produced

Good mobility control was also reflected in the position of the produced chemicals relative to the oil bank. Figure 8 for NaOH plus ORS-162HF plus 550 mg/L Flopaam 3230S shows the chemical banks behind the oil bank.

Chemical retention by the Big Sinking rock is low. Sodium hydroxide average retention was 354 lb/acre-ft and sodium carbonate average retention was 1,484 lb/acre-ft. Surfactant average retention was 134 lb/acre-ft and that of polymer was 77 lb/acre-ft.

Injectivity to fresh water after injection of the alkaline-surfactant-polymer and polymer solutions generally declined as shown in Table 3. Sodium hydroxide systems did not lose as much injectivity as did sodium carbonate systems. Linear corefloods demonstrated the same conclusion. Figure 9 shows that with a NaOH plus ORS -162HF system, injectivity actually improved despite the permeability reduction of the polyacrylamide polymer.

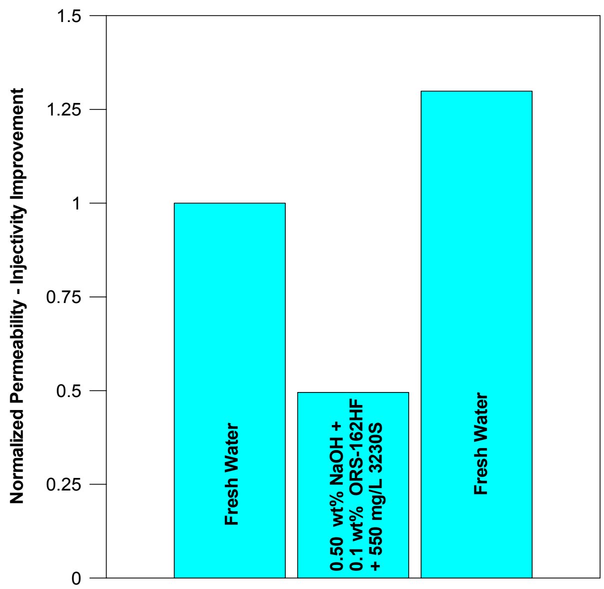


Figure 9 Injectivity Improvement as Normalized Effective Water Permeability, for Injection of NaOH-ORS-162HF-Flopaam 3230S in a Radial Coreflood

C. Field Evaluations

1. Core of Well and Well Location

The test well, #1T E.L. Rogers, was air drilled to a total depth of 1,217 feet. An 8 ¾ inch hole was drilled to 1,120 feet (just above the zone to be cored) and 7 inch casing was run and cemented to surface. The Corniferous formation was cored with a total of 60 feet of 4 inch core from 1130 to 1190 feet being recovered. The well was open hole logged showing a net of 25 feet of continuous net pay in the primary waterflood zone and 11 feet from a lower, tighter zone.

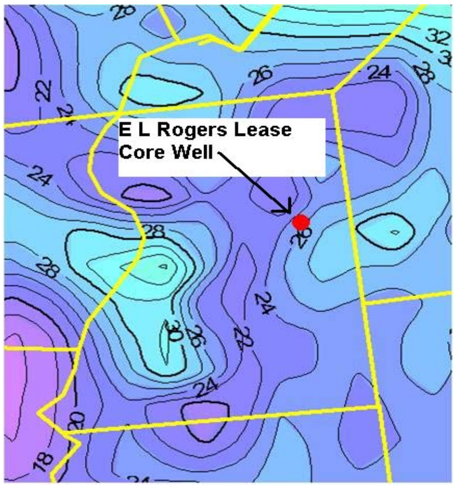


Figure 10 Single Well Injectivity Test Well Location and Net Pay Isopach

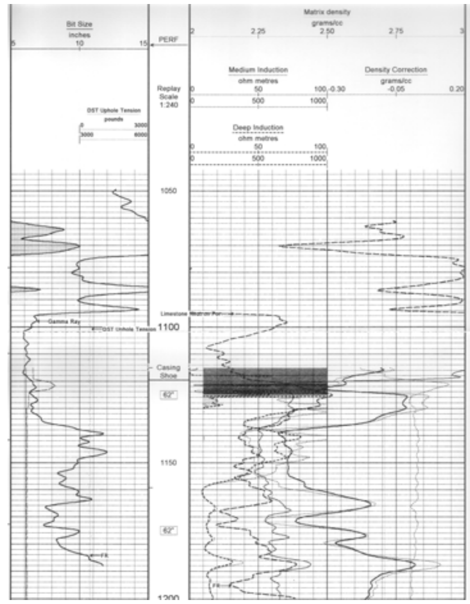


Figure 11 Log of #1T E.L. Rogers Well

The resistivity is high on the log due to the injection of fresh water. The log is shown in Figure 11.

2. **Injectivity Test**

The injectivity test was performed by injecting fluid into the #1T E.L. Rogers well. Water was initially be injected followed by alkaline-surfactant solution followed by water. The initial alkaline-surfactant solution selected from the linear corefloods, 0.75 wt.% NaOH plus 0.2 wt.% AX-210-6, had to be replaced with a 0.50 wt.% NaOH plus 0.1 wt.% ORS-162HF solution because of the manufacturers inability to supply the AX-210-6. Radial coreflood injectivity improvement with the NaOH plus ORS-162HF plus polymer solution is shown in Figure 9.

a. **Well Set Up** - The cored well was completed for the injectivity test open hole. First the well was plugged back to 1162 feet (354 m), just below the primary zone. Second, the well was bailed clean with a service rig and bail tested at 30 barrels per day. Third, two inch, internally lined tubing and a packer were run to 1100 feet.

b. **Surface Equipment** - The pumping and mixing equipment were designed to use liquid NaOH delivered in 55 gallon drums at 50 wt %. Surfactant was also delivered in 55 gallon drums at 50% active. The primary mixing constraint was to blend the NaOH with water prior to adding the surfactant. The pH prior to adding the surfactant was approximately 13.2. The resultant solution was filtered to 5 microns. All piping downstream of added NaOH was stainless steel including the injection pump. The pump was setup as a mixer for NaOH with part of the pumped volume being recycled. The surfactant was mixed into the injection solution downstream of the pump. Two chemical injection pumps were setup to be able to blend 0.5 wt% NaOH plus 0.1 wt% active ORS-162HF. At the required concentrations of chemicals, the injection pump volumes were

27.4 gallons of NaOH (50 wt%) and 8.0 gallons of surfactant (50% active) per 100 barrels of fresh water. The maximum wellhead pressure was set at 800 psig.

c. **Injectivity Test Program** - The injectivity test was to be completed in four months. The injected sodium hydroxide/ORS-162HF solution was preceded with a pre-flush of 1,500 barrels of fresh water. During the pre-flush, a base injection rate and injection pressure was established. Next, 1,500 barrels of an alkaline-surfactant solution was injected to treat approximately a 25 foot radius around the wellbore. Fresh water is then injected to establish the injection rate and injection pressure followed by the injection of produced water.

d. **Injection History** - Injection of fresh water started on September 5, 2003. The initial injection rate was 90 BWPD. After one month and 2,600 barrel of continued water injection, the rate stabilized at 41 BWPD and 910 psig bottom hole pressure. The alkaline-surfactant solution injection began at the 41 BWPD; however, after injecting for one day the well pressured up to the maximum bottom hole pressure of 1,180 psi and the rate dropped below 20 BWPD. The well was shut in. A ¾ inch circulating string was run in and circulated the well clean. Samples of the bottoms up material along with the surfactant, source water, and filter element were sent to lab for analysis. It was discovered that while water the divalent cation concentration of the water used in the laboratory for chemical dissolution were low enough to dissolve alkali, the city water used in the injectivity test required softening. A loss of injectivity resulted due to precipitation and skin damage. The injection rate decline was compounded by mixing too high a concentration of chemicals due to mechanical difficulties. An attempt to restart water injection was made but the skin damage was too great. Two hundred gallons (5 bbl) of 15% HCl was spotted on bottom of the well. Injectivity was restored by dissolving the hardness precipitate causing the skin damage. The initial injection pump had to be changed out due to the packing not being resistant to a high pH fluid. A 500 barrel buffer of fresh water was injected. Alkali plus surfactant dissolved in softened city water injection resumed on November 21, 2003. The equipment was initially designed to run in warmer weather. Because the 50 wt.% NaOH solution solidifies at 40^{o}F, the equipment had to be weatherized. NaOH was stored in a warm building and brought out as needed. The 1,500 barrel treatment of alkaline-surfactant solution was completed on December 25, 2003. A nine day injection of fresh water followed. Stabilized fresh water injection rate was 75 BWPD at 760 psig an increase of over 30 BWPD at lower injection pressure.

If injectivity change ratio is defined as

$$Injectivity\ Change = \frac{\left[q / \Delta P\right]_{final}}{\left[q / \Delta P\right]_{initial}}$$

where q is injection rate, ΔP is the bottom hole injection pressure, final is water injection after chemical, and initial is water injection before chemical, the injection improvement due to injecting the alkaline-surfactant solution is 2.19. This represents a 220% increase in injection rate, about two thirds the order of magnitude observed in the linear corefloods and greater than that observed with the NaOH plus ORS-162HF-polymer radial coreflood.

D. **Economics of Alkaline/Surfactant Treatment**

The basic ingredients of the treatment are alkali and surfactant. The delivered cost for the NaOH was US$1,725, including US$500 deposit on the drums. The designed surfactant was US$1,250 delivered on site from Houston, TX. Design costs are dependent upon the economies of scale. Fresh water used will be dependent upon hardness and availability in the area. Pumping and blending equipment is dependent upon the degree of automation. In this case, the field treatment cost estimate is US$8,500. For a mature waterflood with an efficiency of 15:1 (barrel injected/barrel oil produced), a 30 barrel increase in water injection would result in a payout time of approximately 8 months with oil at US$25/bbl.

E. **Technology Transfer**

The single well injectivity test has been presented and reported to the Stripper Well Consortium. A paper has been written which will be presented at the SPE/DOE Fourteenth Symposium on Improved Oil Recovery, Tulsa, Oklahoma, April 17-21, 2004.[3] A copy of the SPE paper is included with this report. Additional technology transfer activities will be performed as allowed.

Conclusions

1. Fluid analysis and core displacement testing using actual reservoir core and fluids and field injectivity testing are good prediction tools to estimate the relative increase by chemical injection into a well to increase injectivity. Water injection rate was increased 220% in the field compared to 320% in linear coreflood using alkali plus surfactant and 130% with radial coreflood using alkali plus surfactant plus polymer.

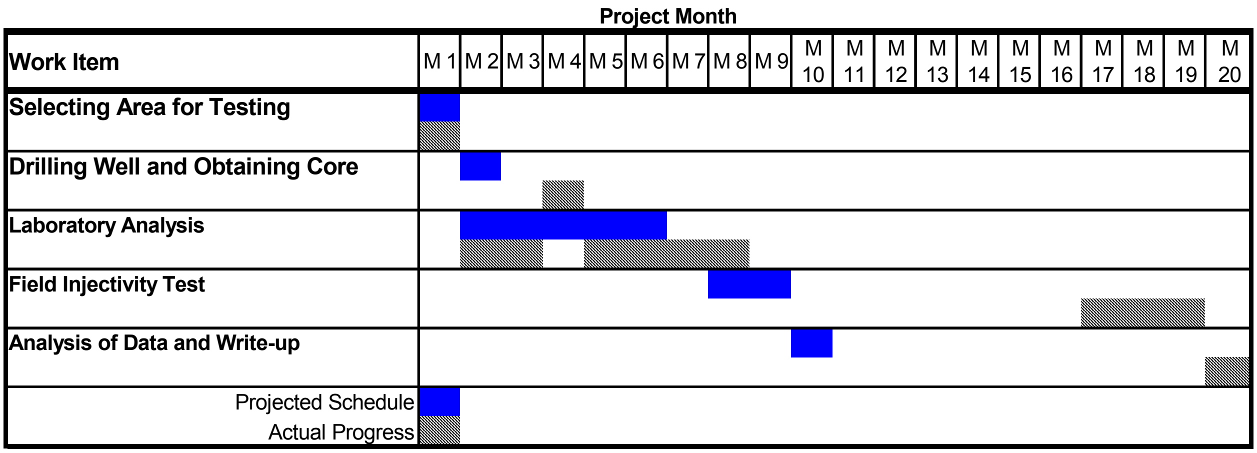
2. A properly designed alkaline-surfactant solution has the ability to significantly increase the effective permeability to water and, therefore, increase injectivity.

3. While the injection process is relatively simple, tight quality control is needed to maintain the consistency of the mixture during the long treatment period.

4. The alkaline-surfactant treatment process offers a relatively inexpensive option for small and large producers for increasing the long term injectivity of injection wells.

Project Schedule and Budget

The project is complete and within budget.



Actual expenditures are compared with the budgeted expenditures in Table 4.

Table 4
Big Sinking Actual and Budgeted Expenditures

Expenditure Category	Budgeted	Actual	Cost Share
Selecting Area for Testing	$ 5,000	$ 5,000	$ 5,000
Drilling Well and Coring	$ 38,000	$ 34,921	$ 34,921
Laboratory Program	$110,000	$110,000	$ 11,000
Injectivity Field Test	$ 10,000	$ 37,825	$ 37,825
Information Dissemination	$ 5,000	$ 5,000	$ 5,000
Travel for Presentations as of 1-31-04	$ 4,000	$ 1,782	$ 1,782
Total	$172,000	$194,528	$ 95,528
% Cost Share			49%

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2. Sydansk, R.D.: “Stablizing Clays with Potassium Hydroxide,” J. Pet. Tech., August 1984, pages 1366-1374.

3. Miller, B., Pitts, M.J., Dowling, P., and Wilson, D.: “Single Well Alkaline-Surfactant Improvement Test in the Big Sinking Field,” SPE 89384, presented at the SPE/DOE Fourteen Symposium on Improved Oil Recovery, Tulsa, OK, April 17-21, 2004.