

Poison Spider Field Chemical Flood Project, Wyoming

Final Technical Progress Report

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Abstract

A reservoir engineering and geologic study concluded that approximate 7,852,000 bbls of target oil exits in Poison Spider. Field pore volume, OOIP, and initial oil saturation are defined.

Potential injection water has a total dissolved solids content of 1,275 mg/L with no measurable divalent cations. If the Lakota water consistently has no measurable cations, the injection water does not require softening to dissolve alkali. Produced water total dissolved solids were 2,835 mg/L and less than 20 mg/L hardness as the sum of divalent cations. Produced water requires softening to dissolve chemicals. Softened produced water was used to dissolve chemicals in these evaluations. Crude oil API gravity varies across the field from 19.7 to 22.2 degrees with a dead oil viscosity of 95 to 280 cp at 75°F.

Interfacial tension reductions of up to 21,025 fold (0.001 dyne/cm) were developed with fifteen alkaline-surfactant combinations at some alkali concentration. An additional three alkaline-surfactant combinations reduced the interfacial tension greater than 5,000 fold. NaOH generally produced the lowest interfacial tension values. Interfacial tension values of less than 0.021 dyne/cm were maintained when the solutions were diluted with produced water to about 60%. Na₂CO₃ when mixed with surfactants did not reduce interfacial tension values to levels at which incremental oil can be expected. NaOH without surfactant interfacial tension reduction is at a level where some additional oil might be recovered.

Most of the alkaline-surfactant-polymer solutions producing ultra low interfacial tension gave type II- phase behavior. Only two solutions produced type III phase behavior. Produced water dilution resulted in maintenance of phase type for a number of solutions at produced water dilutions exceeding 80% dilution. The average loss of phase type occurred at 80% dilution.

Linear corefloods were performed to determine relative permeability end points, chemical-rock compatibility, polymer injectivity, dynamic chemical retention by rock, and recommended injected polymer concentration. Average initial oil saturation was 0.796 Vp. Produced water injection recovered 53% OOIP leaving an average residual oil saturation of 0.375 Vp. Poison Spider rock was strongly water-wet with a mobility ratio for produced water displacing the 280 cp crude oil of 8.6. Core was not sensitive to either alkali or surfactant injection. Injectivity increased 60 to 80% with alkali plus surfactant injection. Low and medium molecular weight polyacrylamide polymers (Flopaam 3330S and Flopaam 3430S) dissolved in either an alkaline-surfactant solution or softened produced water injected and flowed through Poison Spider rock. Recommended injected polyacrylamide concentration is 2,100 mg/L for both polymers for a unit mobility ratio. Radial corefloods were performed to evaluate oil recovery efficiency of different chemical solutions. Waterflood oil recovery averaged 46.4 OOIP and alkaline-surfactant-polymer flood oil recovery averaged an additional 18.1% OIP for a total of 64.6% OOIP. Oil cut change due to injection of a 1.5 wt% Na₂CO₃ plus 0.05 wt% Petrostep B-100 plus 0.05 wt% Stepantan AS1216 plus 2100 mg/L Flopaam 3430S was from 2% to a peak of 23.5%. Additional study might determine the impact on oil recovery of a lower polymer concentration.

An alkaline-surfactant-polymer flood field implementation outline report was written.

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Introduction

The alkaline-surfactant-polymer technology was investigated to determine if economic, incremental oil could be produced from a reservoir containing 150 to 300 cp crude oil. Target field is the Crow Mountain reservoir of the Poison Spider field in Wyoming. Work was split into two sections: a field evaluation defining oil target and field characteristics, and a laboratory section to demonstrate that the alkaline-surfactant-polymer technology is applicable as well as designing an injected solution for field implementation. Finally, a field application outline was written.

Poison Spider Field was discovered in 1917 and was a gas supply source for Casper, Wyoming. The field is in Natrona County, Wyoming and operates from federal leases. In 1919, oil was discovered in a lower horizon of the Crow Mountain sand at a depth of 1400 to 1500 ft. Initial production was reported at 100 BOPD of 22.5 degree API oil. Current production is 94 BOPD at an oil cut of 7%. The principal oil and gas trapping mechanism in the Poison Spider Field is anticlinal folding. Original gas/oil contact was +4375 sub sea and original water-oil contact was between +4200 and +4300 feet sub sea. Average porosity is 18% and average permeability is 240 md. A total of 4.148 million barrels of oil has been produced through 2003.

An estimated additional 2.5 million barrels can be produced by application of the alkaline-surfactant-polymer process at a total produced cost of \$4 to \$5 per barrel by reducing capillary forces that trap waterflood residual oil using alkali and surfactant, and improving sweep efficiency by improving mobility ratio using polymer. A well was drilled to obtain core material, reservoir properties, and logging data for current saturation determinations. This information was correlated with other well data and production performance to determine the reservoir character of the Poison Spider field. Core data also helped estimate the current saturation conditions and the target oil for enhanced oil recovery. Core material and produced fluids from the field were used in the laboratory program to 1.) Define chemical systems that provide significant interfacial tension reductions and are compatible with the reservoir rock and fluids. 2.) Define polymer concentrations required for mobility control. 3.) Determine oil recovery potential in radial corefloods using optimized systems. 4.) Demonstrate that a 280 cp crude oil can be mobilized economically with a chemical flooding technology.

Executive Summary

Reservoir Engineering-Geologic Evaluation

Field pore volume estimate ranges from 13,826,000 to 15,592,000 bbls. Original oil in place was 10,231,000 to 12,278,000 bbls. Oil recovery from 1924 through 2003 is 4,148,000 bbls. Oil target for chemical enhanced oil recovery is 7,852,000 bbls.

Laboratory Program

Fluid-Fluid Evaluation

Interfacial tension reductions of up to 21,025 fold (0.001 dyne/cm) were developed with fifteen of the alkaline-surfactant combinations at some alkali concentration with a 280 cp, 21 API gravity crude oil. NaOH and Na₂CO₃ plus surfactant solutions produced interfacial tension values as low as 0.001 dyne/cm. Interfacial tension values of less than 0.021 dyne/cm were

maintained when the solutions were diluted with produced water to about 60%. NaOH was better at maintaining low interfacial tension values when diluted with unsoftened produced water than Na₂CO₃. NaOH interfacial tension reduction is at a level where some additional oil might be recovered without surfactant addition.

The majority of the alkaline-surfactant-polymer solutions producing ultra low interfacial tension gave type II- phase behavior. Only two solutions produced type III phase behavior. Produced water dilution resulted in maintenance of phase type for a number of solutions at produced water dilutions exceeding 80% dilution. The average loss of phase type occurred at 80% dilution.

Linear Corefloods

Linear coreflood evaluations indicate that Poison Spider is a good candidate for alkaline-surfactant-polymer flooding. A mobility ratio for produced water displacing 280 cp crude oil is 8.6. Linear corefloods indicate that water is a poor displacing agent and that polymer inclusion will improve oil recovery performance. Poison Spider core was not sensitive to alkali, surfactant, or polymer. Chemical solutions injected into and flowed through Poison Spider rock. Injection of either a NaOH-surfactant or Na₂CO₃-surfactant solution improved injectivity by 125 to 290%. Only the NaOH-surfactant Injectivity improvement persisted with subsequent produced water injection. Flopaam 3330S and Flopaam 3430S injected into the core dissolved in either alkaline-surfactant solution or softened produced water. Recommended injected concentration for both polymers is 2,100 mg/L. Alkalis, surfactant, and polymer retention by Poison Spider core is low. All retention values are acceptable for a field application. Effluent analysis indicates the chemical systems used in the linear corefloods were over designed, suggesting that alkali concentrations should be reduced for optimum oil recovery.

Radial Corefloods

Radial coreflood data indicates that an alkaline-surfactant-polymer flood should be implemented in the Poison Spider field. Average initial oil saturation was 0.775 Vp and with an average waterflood oil recovery of 46.4% OOIP after injection of 2.4 Vp. Waterflood residual oil saturation averaged 0.416 Vp.

Average alkaline-surfactant-polymer oil recovery was 18.1% OOIP ranging from a low of 8.2% OOIP to a high of 31.6% OOIP. Peak chemical flood oil cuts ranged from 12.1% to 43.1% indicating that a bank of oil was developed with all chemical solutions and that incremental oil can be produced from Poison Spider by chemical injection. Total oil recovery averaged 64.6% OOIP ranging from 60.8% OOIP to 69.6% OOIP. Average final oil saturation was 0.275 Vp.

Chemical retention was low for all chemicals. Maximum chemical retention for any chemical was 336 lb/acre-ft. Chemicals moved in unison through the core so the interfacial tension reduction capacity will be maintained with injected solutions.

Resistance factor data indicates that polymer, surfactant, and alkali will inject and flow through Poison Spider rock. Mobility ratio of 2100 mg/L polymer provides efficient displacement of crude oil with chemical solution mobility ratio being close to 1 or less.

Resistance factor and produced chemical data indicate that 2100 mg/L polymer concentration can be reduced to optimize economics. Lower alkali concentrations and, possibly, use of ORS surfactants could further improve economics. Based on the radial coreflood results, chemical cost averages \$3.51 per incremental barrel of oil.

Experimental

Aqueous cation concentrations were determined by atomic adsorption spectroscopy (EPA method 213.1). Aqueous chloride was analyzed using a diphenyl carbazone titration (EPR 252.3). Sulfate concentration was measured using a barium turbidimetric technique (EPA 208.1). Carbonate and bicarbonate concentrations were determined by titration with HCl.¹

Crude oil was dewatered prior to use by centrifugation. Water content of crude oil was measured using a Karl Fischer technique (ASTM D 1744). API gravity was determined using a pycnometer (ASTM D 287). Crude oil viscosity was measured using a Brookfield viscometer equipped with a UL adaptor.

Interfacial tension between crude oil and aqueous fluids was measured using a temperature regulated, variable speed spinning drop tensiometer, University of Texas model 500.² Phase behavior was determined by mixing an equal volume of crude oil and aqueous solutions, mixing, and equilibrated at 75°F for two weeks. Phase behaviors were evaluated using the criteria of Nelson and Pope.³

Core plugs for linear corefloods with dimensions of 1 inch diameter by 3 7/8 inches in length were drilled from preserved core using produced water as the bit coolant. Core was saturated with produced water by evacuation. Core was placed in a radial type core holder and crude oil injected to establish an initial oil saturation. Produced water was injected to residual oil saturation followed by alkaline-surfactant-polymer solutions. Three alkaline-surfactant-polymer solutions were injected with 500, 1000, and 1500 mg/L polyacrylamide polymer. Each solution was injected at three frontal advance rates with an unsoftened produced water flush in between. Final chemical solution injection was 1000 mg/L polyacrylamide polymer dissolved in softened produced water. Differential pressures were measured over the entire core length with an internal pressure from the injection face to one inch behind the injection face.

Core discs for radial corefloods with dimensions of 2 inches high by 3 3/4 inches in diameter were drilled from preserved core using produced water as the bit coolant. Core was saturated produced water by evacuation. Core was placed in a Hassler type core holder and crude oil injected to establish an initial oil saturation. An average of 3.1 pore volumes of produced water was injected to simulate a waterflood. An average of 0.352 pore volume of alkaline-surfactant-polymer solution followed by 0.350 pore volumes of polymer drive solution were injected. Final injectant was a 2.42 pore volume water flush. Differential pressures were measured over the entire core diameter with an internal pressure from the injection well bore to one inch in diameter from the injection well bore.

Linear and radial corefloods were performed at 75°F. Produced fluids of the linear and radial corefloods were analyzed for alkali, surfactant, and polymer concentrations. Sodium carbonate

and sodium hydroxide concentrations were determined by titration with HCl.⁴ Surfactant concentration was determined using a dual phase hyamine titration.⁵ Polymer concentrations were determined according to Scoggins.⁶ Residual oil saturation was measured using a Soxhlet extraction technique.

Results and Discussion

Engineering Analysis

A classical engineering and geological analysis estimates a field pore volume of 13,826,000 to 15,592,000 bbls. Original oil in place was 10,231,00 to 12,278,000 bbls. Depth varies from 1,350 to 1,500 ft. Average porosity is 21.1% and the average permeability is 450 md. Original oil saturation based on laboratory analysis is 77.5%.

Oil recovery from 1924 through 2003 is 4,148,000 bbls. Average oil cut over the last 26 years is 9.2%. Current oil cut is 7%, 94 bbl oil per day and 1,275 bbl water per day. Oil target for chemical enhanced oil recovery is approximately 7,852,000 bbls, 0.503 to 0.568 Vp.

Oil and Water Analysis

Produced water and a source water to potentially dissolve chemicals for injection were collected. Well G-13 produced water had a total dissolved solids content of 2,835 mg/L with a total hardness ion content of 19 mg/L. Total dissolved solids and hardness of produced waters from across the field were consistent, varying from 2,160 to 3,430 mg/L total dissolved solids. Lakota water is a possible secondary water that could be used for dissolving chemicals. Lakota water had a total dissolved solids content of 1,275 mg/L with a total hardness ion content of essentially zero.

Poison Spider crude oil samples were collected from wells across the field. API gravities varied from 19.8 up to 22.2 degree. Viscosities varied from 95 cp up to 280 cp at 75°F. The majority of oil API gravities were in the 21.5 degree range with viscosities of 120 cp. Interfacial tension between oil and produced water is 21.0 dyne/cm.

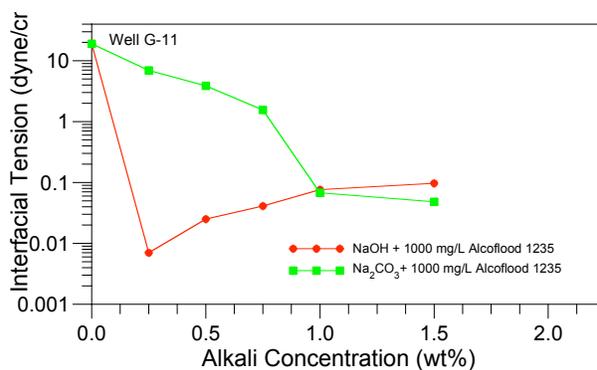


Fig. 1 Interfacial Tension between Well G-11 Crude Oil and Aqueous Alkali

Alkali Interfacial Tension Evaluation

Two alkaline salts, sodium hydroxide (NaOH) and sodium carbonate (Na₂CO₃), were dissolved in softened produced water, and the interfacial tension between Poison Spider crude oil from a number of wells and the aqueous alkaline solutions were determined at 75°F. Figures 1 and 2 depict interfacial tension as a function of alkali concentration for two of the oils. Poison Spider crude oil shows interfacial tension reduction with NaOH but not Na₂CO₃ with both crude oils. A 675 fold interfacial tension reduction was observed at

approximately 0.35 wt% NaOH.

Alkaline plus Surfactant Solution Interfacial Tension Reduction

Combinations of alkali and surfactant can have lower interfacial tension values than either chemical alone.^{7,8} Seventeen surfactants of varying structure and molecular weight were evaluated after determining stability in softened produced water. Surfactants were from three manufactures. Structures were primarily alkyl aryl sulfonates, alkyl naphthalene sulfonates, linear chain sulfonates, and alpha olefin sulfonates. Surfactants and surfactant blends were mixed with each alkali type at alkali concentrations from zero to 2.00 wt%. Total surfactant concentration was 0.05 wt% to 0.10 wt% active. Low surfactant concentrations were selected for economic viability of the chemical flood. Interfacial tension between the aqueous alkaline-surfactant-polymer solutions and Poison Spider crude oil was measured at 75°F. None of the surfactants without alkali reduced the interfacial tension to values sufficient to produce incremental oil at 0.1 wt%. The best interfacial tension reduction with surfactant alone was 36 fold with a blend of ORS-57HF and Stepanan AS-1216. Addition of alkali to the surfactant solutions

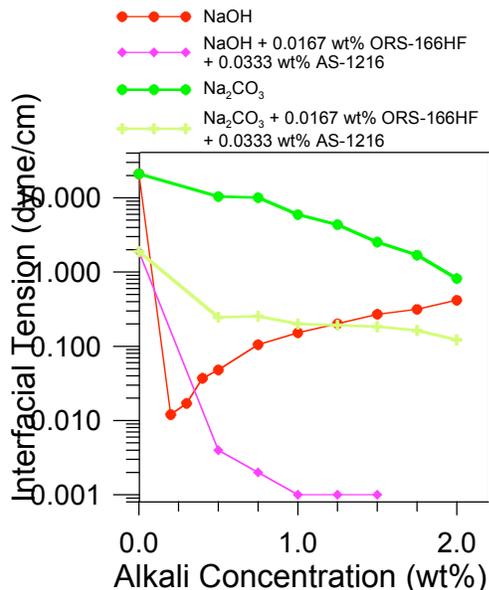


Fig. 4 Interfacial Tension between Crude Oil and Alkali plus ORS-166HF and

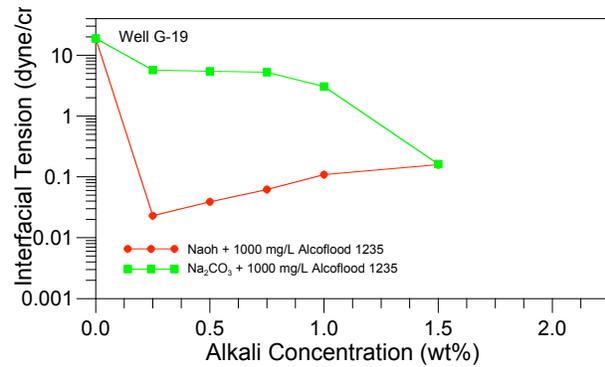


Fig. 2 Interfacial Tension between Well G-19 Crude Oil and Aqueous Alkali

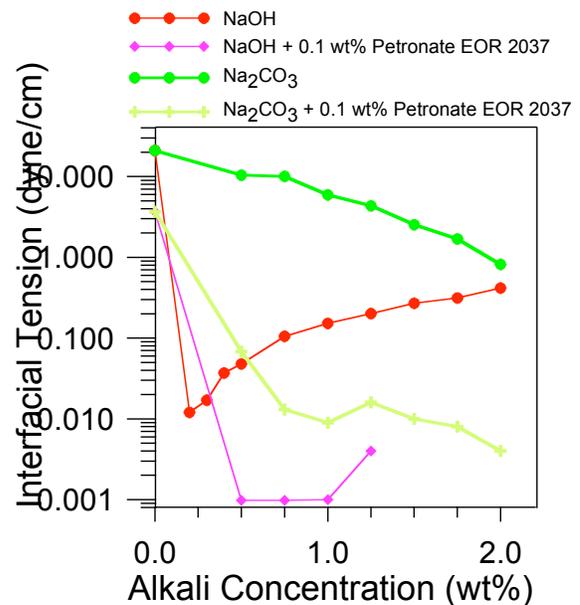


Fig. 3 Interfacial Tension between Crude Oil and Alkali plus Petronate EOR 2037 Solutions

greatly improved results. Every surfactant tested lowered interfacial tension values compared to water by approximately 2,000 fold (0.010 dyne/cm or less) with at least one of the alkaline-agents. Fifteen of the seventeen surfactants provided interfacial tension reductions of 10,000 fold (0.002 dyne/cm or less) or more when blended with alkali. Figures 3 and 4 show typical interfacial tension reduction with surfactant and alkali. Figure 3 shows the interfacial tension reduction with Petronate EOR 2037 and NaOH compared to NaOH with no surfactant, and the same

comparison with Na_2CO_3 . Figure 4 shows a similar set of data for ORS-166HF blended with Stepantan AS-1216. Stepantan AS-1216 is added to stabilize the solution. These two alkali plus surfactant systems are typical of the majority of the chemical combinations in that interfacial tension reductions exceeding 2,000 fold are with NaOH but not Na_2CO_3 .

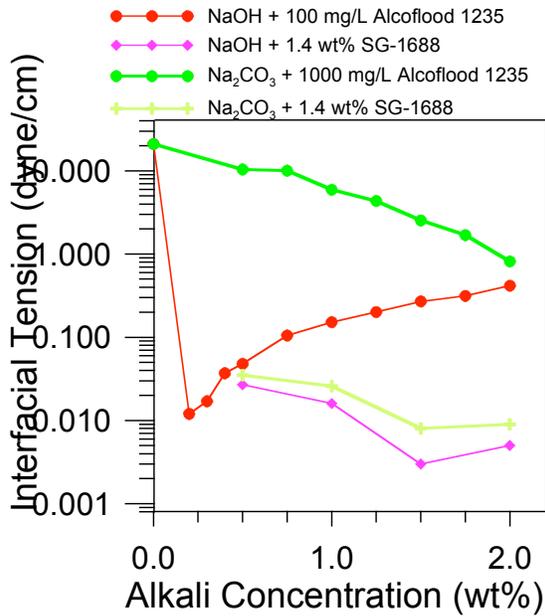


Fig. 5 Interfacial Tension between Crude Oil and Alkali Mixed with a Surfactant-Polymer Molecule

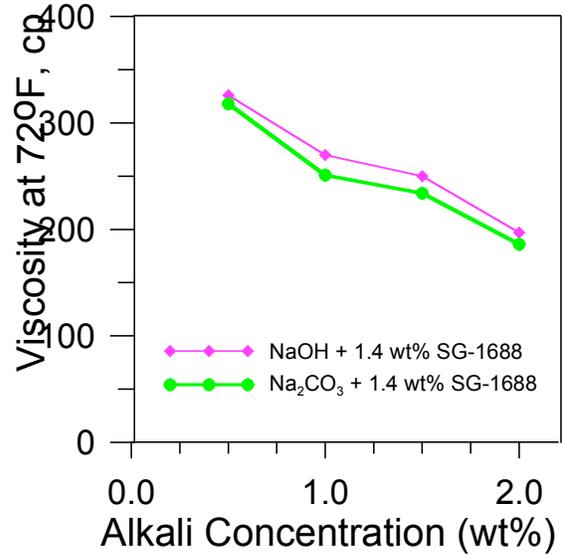


Fig. 6 Viscosity of a Surfactant-Polymer Molecule Solution as a Function of Alkali Concentration

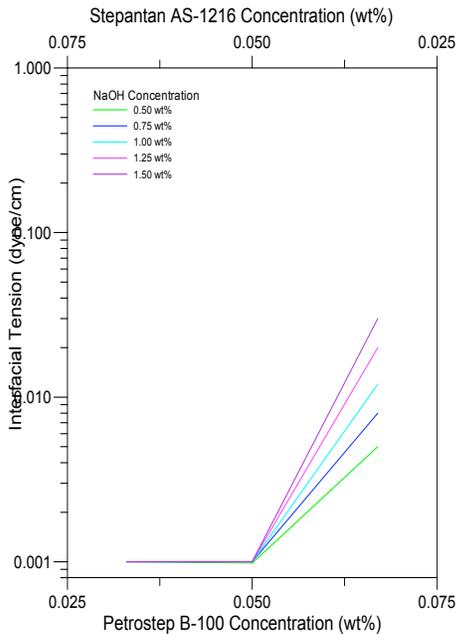


Fig. 7 Interfacial Tension between Crude Oil and a Petrostep B-100 plus Stepantan AS-1216 plus NaOH Solutions of Varying Hydrophilic Character

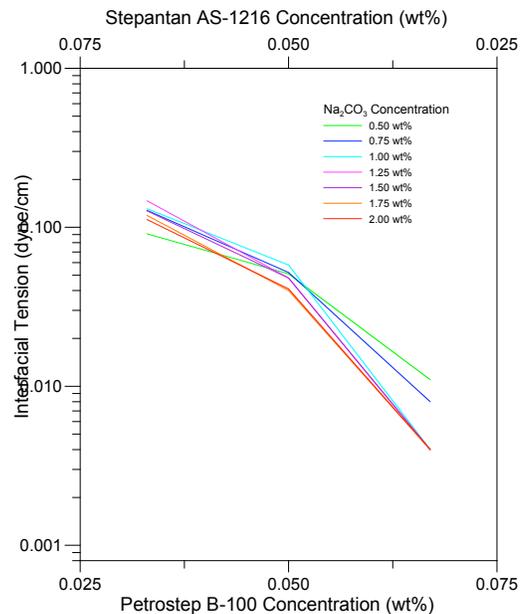


Fig. 8 Interfacial Tension between Crude Oil and Petrostep B-100 plus Stepantan AS-1216 plus Na_2CO_3 Solutions of Varying Hydrophilic Character

The interfacial tension between Poison Spider crude oil and a solution of compound that combines a polymer and a surfactant in the same chemical, SG-1688 (both functional groups in one molecule), blended with NaOH and Na₂CO₃ was tested. Figure 5 depicts the interfacial tension data. Low interfacial tension values were observed with SG-1688 mixed with both alkalis, up to a 7,008 fold reduction. Figure 6 depicts the viscosity developed. Viscosities as high as 326 cp were developed. Like a polyacrylamide, the viscosity is affected by alkali concentration. This is intriguing in that polymer and surfactant are in one molecule. As a result, chromatic separation is not an issue and the solution cost might be lower in that polymer is not required.

Another interesting aspect of this study is the affect of NaOH and Na₂CO₃ on the hydrophilic character of Petrostep B-100 plus Stepantan AS-1216 solutions that produced low interfacial tension solutions. Figures 7 and 8 depict the data. Increasing the concentration of Petrostep B-100 concentration give the solution more hydrophobic characteristics. Conversely, higher concentrations of Steapantan AS-1216 result in a more hydrophilic solution. NaOH solutions lowest interfacial tension values were observed when the solution was more hydrophilic. Na₂CO₃ solutions lowest interfacial tension values were observed when the solution had a greater hydrophobic characteristic.

Phase Behavior of Alkaline-Surfactant Solutions

Phase behavior evaluations were performed to help define which alkaline-surfactant-polymer solutions have the best potential to recover additional oil beyond a waterflood in the Poison Spider reservoir. Nomenclature was according to Nelson and Pope.³ A favorable phase behavior observed over the duration of the evaluation suggests that the interfacial tension between the Poison Spider crude oil and the chemical mixture has remained low throughout the elapsed time. Phase behavior evaluations involved blending the crude oil with equal volumes of the chemical solution and mixing. After approximately two weeks of equilibration at 75°F, the type, appearance, and number of phases observed were recorded.

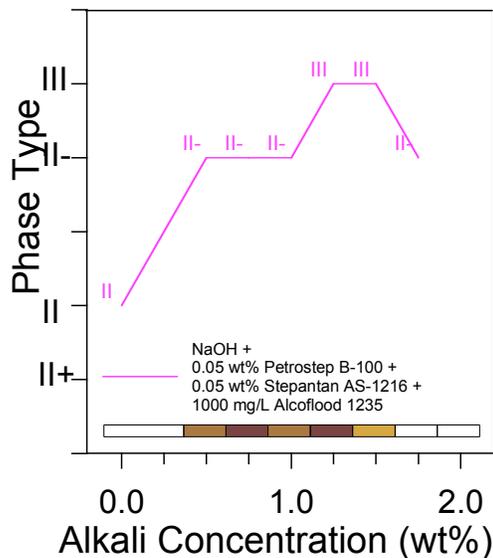


Fig. 9 Phase Behavior of Crude Oil with NaOH plus Petrostep B-100 plus Stepantan AS-1216 Solution

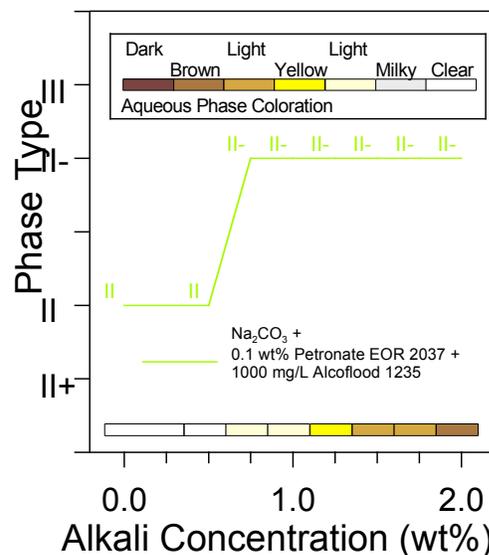


Fig. 10 Phase Behavior of Crude Oil with Na₂CO₃ plus Petronate EOR 2037 Solution

Phase behaviors with just alkali were not favorable in that the only concentration of either NaOH or Na₂CO₃ to demonstrate type II- phase behavior was 0.2 wt.% NaOH. All other concentrations gave type II. When surfactant was added to either alkali type II- phase behavior was observed for thirty-seven of the thirty-eight surfactant-alkali combinations tested. Petrostep-B100 plus Stephantan AS-1216 with NaOH and Na₂CO₃ with Petronate 2095 were the only two solutions to develop type III at high alkali concentrations. Figures 9 and 10 depict typical data for both alkalis. Nomenclature for aqueous phase coloration is located in Figure 10.

Produced Water Effect on Interfacial Tension and Phase Behavior

A number of solutions with low interfacial tension values and favorable phase behavior were diluted with unsoftened produced water to 80%, 60%, 40% and 20% of their original concentration. Interfacial tension between the aqueous solutions and Poison Spider crude oil and phase behavior characteristics were determined at 75°F. Monitoring the interfacial tension and phase behavior changes when the solutions are diluted with unsoftened produced water provides

an estimate of how the injected chemical solution oil recovery potential will change as it moves through the reservoir.

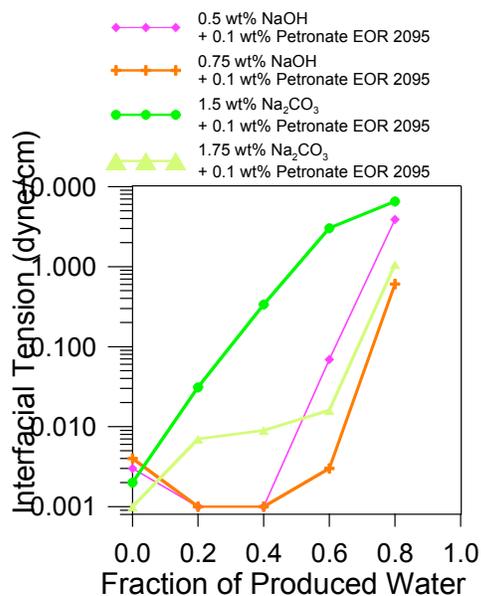


Fig. 11 Effect of Produced Water Dilution on the Interfacial Tension between Crude Oil and Alkali plus Petronate EOR 2095 Solutions

Interfacial tension was maintained at lower values at greater dilution with unsoftened produced water with for NaOH solutions at lower alkali concentrations than Na₂CO₃. A number of the blended surfactant systems (Stepantan AS 1216 with Petrostep B-100 or a number of the ORS surfactants) low interfacial tensions were maintained at very high dilutions. Higher concentrations of alkali generally resulted in better maintenance of the low interfacial tension values. Typical results are shown in Figure 11 for a NaOH and Na₂CO₃ plus Petronate EOR 2095 solutions. Maintenance of ultra low interfacial tension values up to 40 or 60% unsoftened produced water dilution was typical for NaOH solutions. Interfacial tension values of Na₂CO₃ solutions typically began increasing with 20% unsoftened produced water dilution.

Changes in phase behavior characteristics with unsoftened produced water dilution are similar for almost all alkali plus surfactant solutions. Typical dilution phase behavior change is shown in Figure 12.

Drilling of Core

Well G-28 was drilled and a core taken. Sixty feet of core was collected from depth range of 1402 to 1461 ft. Arithmetic mean permeability was 284 md. Mean porosity was 17.5%.

Waterflood and Relative Permeability End Points

Produced water was injected into two linear core plugs from well Poison Spider G-28 at a depth of 1,452.5 and 1,450.2 ft. Average initial oil saturation was 0.796 Vp. Water injection recovered 53.0% OOIP with injection of more than 19 Vp of water. Average waterflood residual oil saturation was 0.375 Vp. Relative permeability to water at residual oil was 0.03. Permeability to water is relative to the effective permeability to oil at immobile water. Mobility ratio for water displacing 280 cp crude oil is 8.6.

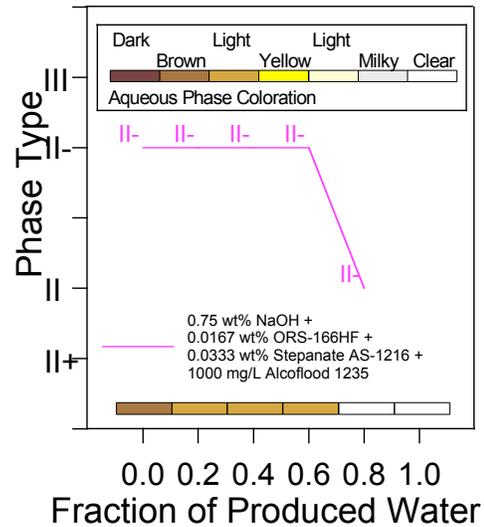


Fig. 12 Effect of Produced Water Dilution on the Phase Behavior Characteristics of an ORS-166HF plus Stepanant AS-1216 Solution

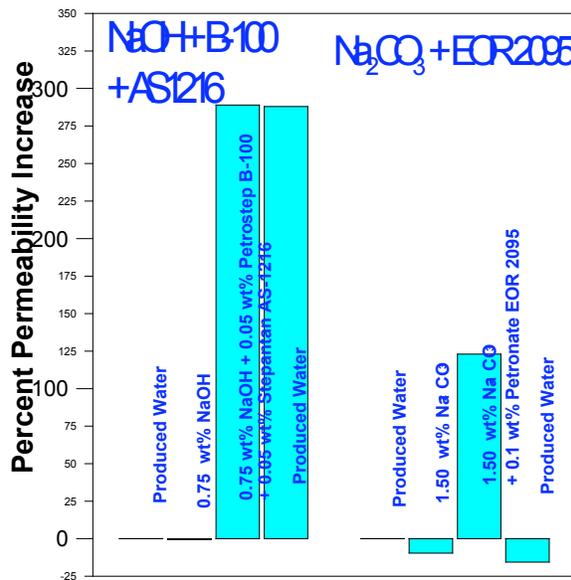


Fig. 13 Injectivity Improvement by Alkaline-Surfactant Solutions in Linear Corefloods

Core-Chemical Compatibility

Poison Spider rock maintained effective water permeability when either NaOH or Na₂CO₃ was injected. Dissolving surfactant into the two alkaline solutions improved injectivity by 125 to 290% during alkaline-surfactant injection. Injectivity improvement was maintained with subsequent produced water injection with the NaOH-Petrostep B-100-AS-Stepantant AS-12116 solution but was not maintained with the Na₂CO₃ plus Petronate EOR 2095 solution. Figure 13 shows the change in effective water permeability with each fluid injected. Poison Spider core is compatible with alkali type and alkali plus surfactant mixtures.

Polymer Injectivity

Flopaam 3330S and Flopaam 3430S injected into and flowed through Poison Spider core dissolved in either alkali plus surfactant solution or in softened produced water. Figure 14 shows the resistance factor change with chemical injection for the Flopaam 3430S. Note resistance factors increased with decreasing injection rate when blended with alkali and surfactant, and in softened produced water, in a manner consistent with the pseudo plastic solution.

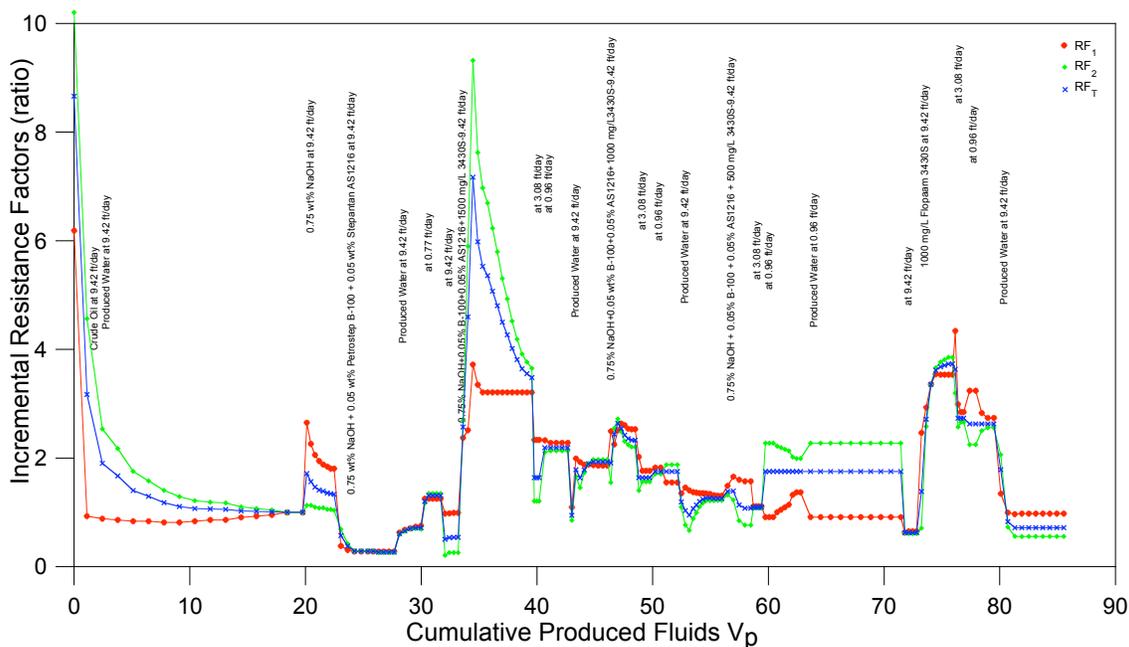


Fig. 14 Incremental Resistance Factor for Flopaam 3430S Solutions as Function of Volume of Fluid Injected

Chemical solutions with Flopaam 3430S injected and flowed through radial coreflows.

Chemical Retention by Poison Spider Rock

Chemical retention by Poison Spider was low for alkali, surfactant, and polymer. Linear coreflood consumption of NaOH was 5,485 lb/acre-ft and was 24,720 lb/acre-ft for Na_2CO_3 . Alkali consumption decreased considerably in radial coreflows to 292 and 218 lb/acre-ft, respectively. Surfactant consumption by Poison Spider sand was also low, ranging from 3,638 lb/acre-ft for Petronate EOR-2095 to 5,407 lb/acre-ft for Petrostep B-100 plus Stepanian AS-1216 in the linear coreflows. Produced surfactant concentrations increase significantly with each unsoftened produced water flush, suggesting that both alkaline-surfactant solutions were over designed and the surfactant was trapped in the oil phase during chemical injection. Alkali concentration should be decreased in both formulations to achieve optimum oil recovery performance. With lower alkali concentrations and less volume of chemical injected, average surfactant consumption in the radial coreflows decreased to 117 lb/acre-ft. Polymer retention

value for Flopaam 3330S was 168 lb/acre-ft during alkaline-surfactant-polymer solution injection. Flopaam 3330S consumption increased to 483 lb/acre-ft when for polymer was dissolved in unsoftened produced water. Flopaam 3430S retention by the Poison Spider rock was similar; 214 lb/acre-ft was retained during alkaline-surfactant-polymer injection that increased to 313 lb/acre-ft during polymer flush injection. Average polymer retention by Poison Spider rock in radial corefloods was 250 lb/acre-ft. Retention of all chemicals by Poison Spider core is acceptable for a field application.

Oil Recovery

Water injection into linear corefloods recovered an average of 53% OOIP, representing primary plus waterflood in the field. Chemical injection increased average oil recovery to 81.2% for a net incremental gain of 28.2% OOIP. Average initial oil saturation was 0.796 Vp with a waterflood residual of 0.375 Vp. Final average oil saturation was 0.149 Vp. Alkaline-surfactant-polymer solution injection recovered 0.226 Vp oil.

Radial coreflood waterflood oil recovery averaged 46.4% OOIP with oil saturation decreasing from an average of 0.775 Vp to 0.416 Vp. A net change is 0.359 Vp. Injection of an alkaline-surfactant-polymer solution reduced the average oil saturation to 0.275 Vp, recovering an average of 18.1% OOIP or 31.6% of the waterflood residual oil saturation. Average chemical flood oil saturation decrease is 0.141 Vp. Average total oil recovery is 64.6% OOIP.

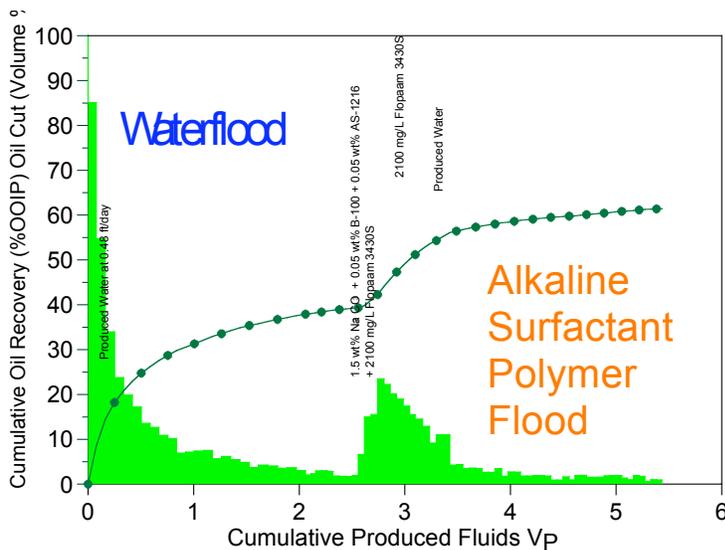


Fig. 15 Radial Coreflood Oil Recovery with a Na₂CO₃, Petrostep B-100, Stepantan AS126, Flopaam 3630S alkaline-surfactant-polymer solution, Oil cut is the histogram and cumulative oil cut is the line plot

Figure 15 shows the cumulative oil recovery and oil cut for a typical radial coreflood in which water was injected for 2.4 Vp followed by an alkaline-surfactant-polymer injection sequence. A solution of 1.5 wt% Na₂CO₃ plus 0.05 wt% Petrostep B-100 plus 0.05 wt% Stepantan 1216 plus 2100 mg/L Flopaam 3430S was the ASP solution injected, followed by 2100 mg/L Flopaam 3430S polymer drive. Produced water injection followed 0.3 Vp of each of the chemical solutions. Waterflood recovered 39.2% OOIP, leaving a waterflood residual oil saturation of 0.478 Vp. Chemical solution injection resulted in oil cut increasing from 2% or less to a peak of 23.5%. Alkaline-surfactant-polymer incremental oil

production was 22.2% OOIP. Total oil recovery was 61.4% OOIP. Final oil saturation was 0.303 Vp for a net oil saturation decrease from the waterflood residual of 0.175 Vp.

Application Outline for an Alkaline-Surfactant-Polymer Flood

A report outlining the steps to implement an alkaline-surfactant-polymer flood in Poison Spider was written. The report emphasized the importance of careful study and analyses of a project before implementation and continuous monitoring of production and injection performance once a project is started. Project study and analyses should include detailed reservoir understanding, design of a chemical solution that will recover economic volumes of incremental oil, numerical simulation to translate laboratory data to field performance, defining the issues and goals of a field application, design and building injection facilities that will mix a chemical solution that has the correct chemical concentrations as well as the required physical characteristics, outlining operating and safety procedures for field personnel, and developing a quality control plan. Field performance monitoring includes production as well as injection data analyses. Periodic produced fluid analysis to supplement oil production is critical to production performance analyses.

Conclusions

Interfacial tension and phase behavior work suggests alkaline-surfactant-polymer flooding has potential for a 100 to 300 cp reservoir like the Poison Spider field. A number of alkaline-surfactant solutions were formulated that provided sufficient interfacial tension reduction and optimum phase behavior to mobilize waterflood residual oil, based on capillary number theory. Poison Spider is a good candidate for chemical flooding based on the fluid-fluid evaluations.

Mobility ratio for produced water displacing crude oil from higher permeability Poison Spider core was 8.6. Water is an inefficient fluid for displacing crude oil from Poison Spider rock. Core displays strongly water-wet characteristics. Water injection recovered an average of 53.0% OOIP after injection of more than 19 pore volumes. Comparative radial coreflood waterflood oil recoveries are 46.2% OOIP after injection of 2.4 pore volumes.

Poison Spider core from well Poison Spider G-28 was not sensitive to NaOH and Na₂CO₃ when injected either with or without surfactant. Poison Spider core showed no sensitivity to surfactant injection. Injectivity improved significantly during alkaline plus surfactant solution with injectivity improvement persisting when a NaOH solution was injected but not with a Na₂CO₃ solution.

Flopaam 3330S and Flopaam 3430S injected and flowed through Poison Spider core from well Poison Spider G-28. Flopaam 3330S showed pseudo plastic behavior. Retention of NaOH, Na₂CO₃, Petronate EOR 2095, Petrostep B-100 plus Stepantan AS-1216, Flopaam 3330S and Flopaam 3430S are acceptable for a field application. Polymer retention was lower when dissolved with alkali and surfactant than when dissolved in softened produced water.

Chemical injection improved oil recovery to 81.2% OOIP from a waterflood oil recovery of 53.0% OOIP. Radial coreflood incremental oil recovery averaged 18.1% OOIP, leaving a final residual oil saturation of 0.275 Vp.

Alkaline-surfactant-polymer flooding is a viable technique to produce more oil than waterflooding from Poison Spider. Two chemical systems produced sufficient incremental oil to warrant consideration for inclusion in a field trial, 1.5 wt% Na₂CO₃ plus 0.05 wt% Petrostep B-100 plus 0.05 wt% Stepantan AS1216 plus 2100 mg/L Flopaam 3430S and 1.0 wt% NaOH plus 0.1 Petronate EOR 2037 plus 2100 mg/L Flopaam 3430S.

Engineering analysis indicates that an oil target of approximately 7,852,000 bbls exists for alkaline-surfactant-polymer flooding. Production of 4,148,000 bbls of oil from 1924 through 2003 has reduced the estimated original oil in place of 10,231,000 to 12,278,000 bbls to current target value. Current oil cut of 7%, 94 bbl per day and 1,275 bbls water per day, suggests Poison Spider is mature.

A report outlining the steps to implement an alkaline-surfactant-polymer flood in Poison Spider was written emphasizing the importance of careful study and analyses of a project before implementation and continuous monitoring of production and injection performance once a project is started.

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