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SURFACTANT-ENHANCED ALKALINE
FLOODING FIELD PROJECT

ANNUAL REPORT

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ABSTRACT

The Tucker sand from Hepler field, Crawford County, Kansas, was characterized using routine and advanced analytical methods. The characterization is part of a chemical flooding pilot test to be conducted in the field, which is classified as a DOE Class I (fluvial-dominated delta) reservoir. Routine and advanced methods of characterization were compared. Traditional wireline logs indicate that the reservoir is vertically compartmentalized on the foot scale. Routine core analysis, X-ray computed tomography (CT), minipermeameter measurement, and petrographic analysis indicate that compartmentalization and lamination extend to the microscale. An idealized model of how the reservoir is probably structured (complex layering with small compartments) is presented.

There was good agreement among the several methods used for characterization, and advanced characterization methods adequately explained the coreflood and tracer tests conducted with short core plugs. Tracer and chemical flooding tests were conducted in short core plugs while monitoring with CT to establish flow patterns and to monitor oil saturations in different zones of the core plugs. Channeling of injected fluids occurred in laboratory experiments because, on core plug scale, permeability streaks extended the full length of the core plugs. A graphic example of how channeling in field core plugs can affect oil recovery during chemical injection is presented.

The small scale of compartmentalization indicated by plugs of the Tucker sand may actually help improve sweep between wells. This prediction is supported by comparison of corefloods and tracer tests conducted with outcrop rock samples of Tallant formation sandstone that have lamination similar to that of Tucker sand core plugs and by the results of several field-scale waterfloods that have been successfully conducted in the Tucker sandstone. The success of field-scale waterflooding and the fluid flow patterns observed in highly heterogeneous outcrop samples are reasons to expect that reservoir flow patterns are different from those observed with short core plugs, and better sweep efficiency may be obtained in the field than has been observed in laboratory floods conducted with short core plugs.

BACKGROUND

The Tucker sandstone (a local equivalent Bartlesville sand) is a Class I reservoir that was deposited in a fluvial dominated deltaic environment. This reservoir is located in southeast

Kansas in Hepler oil field, which extends southward from Bourbon County into Crawford County. The geology of the Hepler site is typical of that of many southeast Kansas reservoirs. In the late 1950s, a large waterflood, the Walter Duncan project on the Shireman lease, demonstrated that the Tucker sand is a candidate for chemical flooding (Powell, 1959). This project was conducted in the S 1/2 Sec 19 R 22E T 27S, which is northwest of the site selected for the field test which is the subject of this report. Cumulative waterflood recovery from the Shireman lease was 161 bbl/acre-ft for 14 ft of sand underlying 215 acres, thus demonstrating that the sand is floodable.

In 1962, Waldo Huning started water injection into three wells on the Elmer C lease, N 1/2 Sec 30 R 22E T 27S, where the field project is to be conducted. Records from this project no longer exist, but response to waterflooding was evidently poor, probably because of microscopic heterogeneity of permeability which has recently been revealed by geologic evaluation of the site with advanced analytical methods.

In 1984, Advanced Recovery Services developed the Elmer C lease for polymer flooding. The company drilled and cored 23 wells. Nine were injectors and the others producers. The lease also had 24 old wells. No records for the amount of polymer used are available. Evidently polymer injection was discontinued after injection of only a small amount of polymer. Flood response was apparently poor, and sustained production was less than 25 BOPD. Core analysis data indicate that the mobile oil content in place in 1984 was approximately 200 bbl/acre-ft. The reason this oil was not mobilized during polymer injection is not apparent. Water channeling through gas sand, induced fractures, or natural fractures could have occurred during the flood. However, there is not enough information available from this project to support a conclusion.

Performance of the current waterflood on the Elmer C lease since 1991 is shown in Fig. 1. Current estimated oil saturation and content in this area (field project area) is 46.3% PV, or 700 bbl/acre-ft which equates to 83,900 bbl oil. For the Elmer C lease overall, it is 46.6%, 684 bbl/acre-ft and 616,000 bbl oil. The water-oil ratio (WOR) has remained steady at about 40 since 1991. Therefore, since the reservoir still contains substantial oil, other methods for recovery, especially a surfactant-enhanced alkaline flood, are under consideration.

Estimates show that 15 to 18% PV (220 to 264 bbl/acre-ft) of mobile oil of the 680 bbl/acre-ft in place in the NE quarter could be recovered. However, an effective polymer flood would be required to recover a substantial amount of this mobile oil at an economic WOR. If another 8% PV of oil could be mobilized with the addition of alkali and surfactant, the potential would be increased to 23 to 26% PV (337 to 381 bbl/acre-ft); the average residual oil being reduced to 20 to 23% (337 to 293 bbl/acre-ft).

RESERVOIR CHARACTERIZATION BY CONVENTIONAL ANALYTICAL METHODS

Well locations at the site of the field project are shown in Fig. 2. Conventional wireline logs were available from all wells. Fresh cores were obtained from wells J-4, H-4, and G-5, which were drilled to complete the injection and production well pattern. Wireline logs for well H-4 are shown in Fig. 3. The pay zone extends from approximately 576 to 587 ft depth. Spontaneous potential (SP) and gamma ray (GR) logs indicate a general fining-upward of sand over the entire interval. The GR log, in particular, indicates the existence of multiple stacked point bar sands, with a fining-upward nature for each sand body. The scale of resolution of the wireline logs is in feet. Overall, the sand appears to be vertically heterogeneous, with perhaps a few feet of homogeneous sand bodies. Logs from wells J-4 and G-5 are very similar to well H-4 logs, with a slight thinning of pay from south to north.

Core plugs were cut from each whole core at 1-ft intervals, and each plug was analyzed for fluid saturation, permeability, and waterflood susceptibility. Well H-4 routine core analysis for permeability is shown in Fig. 4. Routine core analysis indicates 1 ft of core with permeability less than 10 mD, 8 ft of core with permeability between 50 and 150 mD, and 2 ft with permeability of 250 mD. Highest permeability is in the lower portion of the sand, which is consistent with the upward fining nature indicated by the well logs. Overall, the well logs and routine core analyses indicate about 10 ft of permeable sand in this area of the field, using 10 mD cutoff.

RESERVOIR CHARACTERIZATION BY ADVANCED ANALYTICAL METHODS

The entire sand interval in each well was analyzed by X-ray computed tomography (CT) using third-generation equipment originally designed for medical applications and modified for rock analysis with special software and a high-accuracy positioning table. The mathematical relationships for correlation of CT density and rock-fluid properties have been described by Tomutsa et al. (1990). Instrument resolution is 0.5 mm. CT-derived core permeability of the interval from 579.5 to 585.5 ft depth in well H-4 is shown in Fig. 5. Areas of high permeability are shown in dark shades; low permeability, in light shades. Sands with the highest permeability are shown as nearly black, whereas areas with low permeability are shown in white. From Fig. 5, the lenticular, laminated nature of the sand is apparent. Laminations extend from the top of the sand to the bottom of the sand. Laminations extend across the entire width of the core (3 in.). Most of the laminations appear to be nonparallel, and from the apparent angles of individual laminations, it is concluded that the horizontal width of individual sand compartments is less

than previous estimates (Olsen and Johnson, 1993). The horizontal width of individual compartments is probably on the feet or tens of feet scale (French et al., 1993). Some high-energy foreset beds are visible in the lower parts of the sand, and these trough-bedded zones contain the most vertically homogeneous sand bodies.

Figure 6 directly compares CT as an analytical technique with wireline logs. The CT image shows the sand interval between 584.5 and 585.5 ft to be much more complex than indicated by wireline logging. CT shows that this 1-ft interval is the result of many cut-and-fill cycles. The interval between 585.0 and 585.5 ft is some of the most uniform sand in the core from well H-4, but CT imaging reveals the existence of high-permeability variation, on the fraction of an inch (millimeter) scale, over this 0.5-ft interval.

Petrographic image analysis (PIA) was used to determine if variations in rock properties extend to micron scale and pore level. A representative thin section of core is shown in Fig. 7. In Fig. 7, dark shading corresponds to compacted, low-porosity areas, and light shades correspond to mineral grains and porosity. Individual sand grains and pores are identifiable. An area of low porosity extends from left to right across the thin section. This area of low porosity is defined by areas of high compaction of interstitial clays that appear as black bands. The areas of rock with different porosities extend across the rock in a generally horizontal direction. Thin section views show that vertical heterogeneities in the cores can be identified as occurring at the pore and micron level, as well as at the millimeter and meter scales. Core heterogeneities can be detected with all of the analytical techniques so far described including open hole logs (foot scale), routine core analyses (foot scale), CT (millimeter scale), and PIA (micron and pore scale). Routine and advanced core analysis techniques complement one another for characterization of reservoir heterogeneity from large scale to small scale.

The permeability of core plugs was also characterized with a minipermeameter, which allows direct measurement of permeability across core faces. The minipermeameter, shown schematically in Fig. 8, is used to measure permeability a shallow distance into the core face. The degree of resolution of this instrument is the diameter of the o-ring seal, which is 3 mm. In Fig. 9, minipermeability measurement correlates well with CT-derived porosity. Permeability varies greatly across the core face, and the areas of highest permeability correspond to the areas indicated by CT to have the highest porosity. Figure 10 shows permeability distribution from CT and minipermeameter across another core plug. Note that the minipermeameter results at both core faces correlate with the CT results at both core faces and verify that rock heterogeneities extend completely through the length of the 3-in. core plug.

IDEALIZED RESERVOIR MODEL

Analytical information from three wells was insufficient to characterize an entire reservoir, however, sufficient information was available to identify the heterogeneities that exist vertically. The three cores had remarkably complex, yet similar structures. It was not possible to identify individual layers that extend from well to well. The complexity of the layering and the angles of individual layers, which are not exactly parallel, indicate that individual sand bodies probably extend horizontally for only a few feet or tens of feet. Figure 11 shows an idealized model of how the reservoir is probably structured: complex layering with small compartments.

COREFLOODS

Corefloods conducted with field core plugs are summarized in Table 1. Corefloods RP-26, 27, 28, 29, 30, 31, 34, 35, and 36 were performed using chemical slug sizes that could be potentially economic when scaled to field conditions. Typically, these floods were conducted with a total of 0.4 or 0.5 PV of injected chemicals. Surfactant concentrations for the injected chemical slugs were either 0.1 or 0.5% active concentrations of Chevron XP-100 or CF-100 surfactant. NaHCO_3 concentration was between 1.2 and 3.2% in the chemical formulations. STPP (sodium tripolyphosphate) concentration was 0.45% active. In most corefloods, a small chemical slug was followed with 1,200 ppm Alcoflood 1135 polymer for mobility control. (An alternate injection strategy was to include the polymer in the same slug as the other chemicals.) In all cases, formulation was in water from a water supply well on the lease.

Average recovery efficiency from field core plugs was much lower than that from Berea sandstone cores, which was reported previously (French, 1991). For the nine corefloods described above, average recovery efficiency was 9.1%. This included one coreflood, RP-28, which produced no oil during chemical flooding. Average recovery by chemical flooding was 3.7% PV of oil. Corefloods RP-34, 35, and 36, which were performed with a slightly different chemical formulation than the other six corefloods, had an average recovery efficiency of 14.1%, or 6.4% PV. Since an effective polymer flood probably should yield an oil recovery in the range of 11 to 16% PV (160-235 bbl/acre-ft), the results from the coreflooding tests were somewhat disappointing.

Core plugs RP-26 and RP-30 were well characterized with CT and minipermeameter measurements. The results are shown in Figs. 9 and 10. In Fig. 9, the RP-26 minipermeability measurement correlates well with CT-derived porosity. Permeability varies greatly across the core face, and the areas of highest permeability correspond to the areas indicated by CT to have the highest porosity. Figure 10 shows the permeability distribution from CT and minipermeameter measurements across core plug RP-30. Note that the minipermeameter results

at both core faces correlate with the CT results and verify that rock heterogeneities extend completely through the length of the 3-in. core plug.

An injection test was conducted with the core plug shown in Fig. 10. Brine, tagged with potassium iodide, was injected while monitoring the flood with CT. Figure 12 shows that tracer followed a path through the core plug that corresponds to invasion of the areas of high permeability. After only 0.08 PV of tracer injection, tracer was detected at the core outlet end. As tracer injection continued, the portion of the core swept by tracer increased, but after 3 PV of injection, some areas of the core still had not been swept by the tracer. The results of this coreflood could not have been explained from wireline logs and conventional core analyses; however, the results of this coreflood seem reasonable as a result of characterization of the core by advanced analytical techniques.

Minipermeameter measurements are shown for core plugs RP-34, 35, and 36 in Fig. 13. Although somewhat better oil recovery was achieved with these core plugs, permeability variation was nearly as great as that for the other core plugs. Low oil recovery from these core plugs was probably due to poor sweep efficiency that resulted from the high permeability variations in these cores. This effect would be more pronounced during chemical flooding with small pore volumes of injected chemicals than it would for injection of large volumes of water during waterflooding. These cores, in fact, waterflooded quite well.

Eight plug samples were waterflooded from a common header so that injection pressure was the same for all samples. Table 2 lists the incremental oil recovered from each sample and compares the core plug waterflooding results with similar results from waterflooding three radial flood samples. Average oil recovery by waterflooding of the eight plug samples was 17.7% PV; average recovery from the three radial floods was 21.8% PV.

Figure 14 includes plots for each of the three radial samples and the composite plot for the eight plug samples. The composite of the eight plug samples may be illustrative of a problem with this reservoir. The WOR for a recovery of 10% PV of oil ranged from 65:1 to 100:1. The limiting economic ratio is probably in the range of 40 to 50:1.

Only one radial sample responded well to water injection. The other two produced minimal oil below a 5:1 and 8:1 WOR. Average for the three indicated a recovery of 4% PV at a WOR of 3 and 11% PV at WOR of 35. However, current WOR for the NE quarter of the lease is 40:1, and the waterflood recovery since 1984 is about 3.1% PV.

After completing injection of a total of 0.5 PV of alkali-surfactant-polymer during coreflood RP-27, chemical flood recovery efficiency was 5.8% (1.6% PV of oil). Successive injections of more viscous chemical solutions (corefloods RP-27A through 27D), produced progressively more oil. This is exactly the type of behavior that would be expected if channeling is occurring in the core. This is representative of the type of flooding behavior that was seen

during the tracer test conducted in core plug RP-30, which was discussed above. Similar behavior was seen during coreflood RP-29R. Injection of a very viscous alkali-surfactant-polymer slug produced extremely high oil recovery, with 95.5% recovery efficiency. Unfortunately, it is not possible to inject such high viscosity mixtures in the field because formation parting pressure would be exceeded.

Subsequently, core plug RP-27 was cleaned of oil and polymer so that special displacement tests could be made with and without tagged water, followed by oil. Core plug RP-27 was selected because it was the most homogeneous core plug of the several plugs that have been flooded. Permeability across the core faces of the RP-27 core are shown in Fig. 15. Several CT scans were made to determine the flow pattern through the core plug. After cleaning, this core plug was referred to as RP-27E. After oil flooding, the core RP-27E was CT scanned while waterflooding and chemical flooding. The reconstituted sample had an irreducible water saturation of 35.3%. The reservoir is preferentially oil-wet (see Fig. 16), and the high, irreducible water saturation suggests that the wettability of the plug might have been changed from preferentially oil-wet to water-wet. Waterflood residual, however, still was 32.2%; after chemical flood, the residual was 23.4%. Incremental oil and WOR data were obtained for this experiment and are included in Table 3.

Figure 17 is the plot of WOR vs. volume of fluid injected. Oil recovery at the end of water injection was 32.5%, S_{ow} was 32.2%, and WOR was 30:1 with a cumulative injection of about 2.2 PV. A 20% PV of alkali-surfactant mixture was then injected, followed by 20% PV of polymer. During injection of polymer, the WOR decreased from 65:1 to 7:1. Incremental oil recovered after waterflood was 8.7% PV with an end-point WOR under 30:1. The volume of chemical plus chase water was 1.5 PV. (Injection of additional chase brine resulted in recovery of more oil at high WOR.) These results were encouraging.

Since the RP-27E flood was conducted with a slightly different chemical formulation than that of previous floods (0.1% surfactant vs. 0.5% surfactant), three replicate floods were conducted with core plugs RP-34, 35, and 36. These plugs were not cleaned or oil flooded before chemical injection. Average oil recovery from these three floods was 6.4% PV. Maximum recovery was 10.8% PV, and minimum recovery was 3.0% PV. All three floods behaved in a very similar manner. A plot of WOR versus cumulative oil is shown in Fig 18. This plot is for RP-36 and is very similar to the results for RP-34 and 35. In all three floods, WOR decreased as chemical was injected. WOR then increased markedly for about 1 PV of injection. WOR then decreased and then increased again. The first oil production occurred after about 0.5 PV of chemical injection. This production evidently occurred as the alkali, surfactant, and polymer swept through the high-permeability portion of the core plug. The second oil

production occurred later and was probably due to oil being swept from lower permeability portions of the core plug as waterflooding with chase water was continued.

A better understanding of the results from corefloods RP-27, 27E, 34, 35, and 36 was gained from CT results. CT images are displayed with core inlet at the left-hand side of figures. The porosity map for core RP-27 is shown in Fig. 19. Porosity is variable, between 15 and 25%, and average porosity is 22.6%. The porosity map agrees quite well with the minipermeability across core faces shown in Fig. 15. Overall, permeability varies only about two-fold across the core, and this core was more uniform than any of the other cores which were tested. (Compare with Figs. 9, 10, and 13.)

Initially, the core was saturated with brine which was tagged with sodium iodide. Results of injection of 0.3 PV of untagged brine are shown in Fig. 20. Flow is shown to be preferential to higher permeability areas which are physically located in the lower portions of the core at the inlet end.

After the tracer test, the core was oil flooded with field crude. Viscosity of field crude is 69 cP, which assures favorable mobility control during displacement by oil. Displacement of brine by oil is shown in Fig. 21. Displacement was very efficient, but there was still a tendency to have the best displacement in the lower sections of the core. At the end of the oil flood (Fig. 21), average oil saturation was 64.73%. Minimum saturation was about 14%, and maximum was about 86%. Figure 22 shows the distribution of oil across the core for 14 CT slices. The abscissa corresponds to positions across the core plug perpendicular to the bedding planes of the core. The core plugs are 38 mm in diameter and the 0 mm position corresponds approximately to the bottom of the core, as shown in Fig. 21. Oil saturations were fairly uniform across the core except for lower saturation near the edges. The average oil saturation by CT was 64.68% PV which was nearly the same as that calculated from the coreflood effluent volumetric data (64.73% PV).

Oil saturation was followed by waterflooding with tagged brine. CT results are shown in Fig. 23. Initially, most brine flow was in the upper portion of the core, which was not the highest permeability area, but an area with lower oil saturation. The water front then wedged through the central portion of the core to the core outlet. Oil was pushed laterally and toward the edges. Eventually, oil saturation was reduced to an average of 34.79% (calculated from CT for a single, vertical, longitudinal section), with areas as low as 25% and as high as 60%. Figure 24 shows the distribution of oil across the core for each slice that was monitored with CT. The figure shows that the waterflood swept the upper central portion of the core most efficiently. Also, differences in oil saturations were less in this area of the core. Average oil saturation by CT after waterflooding was very nearly equal to volumetric calculations (32.20% PV).

After waterflooding, the core contained both oil and tagged brine. Chemical flooding was commenced with a chemical formulation that was untagged. In Figs. 25, 26, 27, and 28, the flow patterns during chemical flooding are shown. Progress of the chemical flood can be followed by monitoring the concentration of tagging agent left in the core after waterflooding and during chemical flooding. Figures 25 and 26 show qualitatively that the chemical flood followed the same wedge pattern as that of the waterflood. Figure 27 shows that when the chemical slug was followed by tagged chase brine, the flow pattern changed with more flow in the lower portions of the core, very similar to the flow pattern during the tracer test and, to a lesser extent, the oil flood.

After injecting several pore volumes of tagged chase brine, there should have been a correspondence between CT density and oil (or tagged brine) saturation. This correspondence did not prove to be exactly observable. In Fig. 28, the concentration of tagged brine appears to be lower than that expected from the volumetric oil recovery from the coreflood. This may have been due to the presence of trapped polymer in the core.

Figures 29 and 30 also show the concentration of tagged brine for 14 slices of the core during chemical flooding. These figures are only qualitative because during the chemical flood it was impossible to distinguish untagged chemical from oil, which was also untagged. Figures 31 and 32, which are after injection of several pore volumes of tagged chase brine, are normalized so that the average oil saturation determined by CT is equal to the oil saturation determined volumetrically. These figures show that oil was displaced from the core very efficiently in the area of the data point position 18 mm from the core edge, with oil saturation in that area varying from about 10 to 25%. Oil saturations across the core at other positions vary to a greater extent, with an average saturation of about 23% in Fig. 31 and 16% in Fig. 32.

SUMMARY

Cores from the Tucker sandstone from Hepler oil field were characterized with routine and advanced analytical techniques. Routine core analyses and wireline logs indicated that sand properties vary with depth. Wireline logs indicate a general fining-up sequence, with several point bar sands being identifiable. Routine analyses of core plugs, taken at 1-ft intervals, demonstrated that 100% and greater changes in permeability occur over small vertical reservoir distances.

Cores were also evaluated with advanced analytical techniques: X-ray computed tomography (CT), petrographic image analysis (PIA), and a minipermeameter. Advanced analytical techniques demonstrated that heterogeneity and lamination extend to the microscale. There was good agreement among all analytical methods, with advanced techniques allowing

better resolution at smaller scales than could be achieved with the routine methods used for reservoir characterization.

Flow patterns during tracer tests in cores were adequately explained by characterization of core plugs with advanced analytical techniques. Channeling of injected fluids occurred in laboratory experiments because, on core plug scale, permeability streaks extended the full length of the core plugs. A good graphic summary of how channeling affected oil recovery by the chemical formulation is shown in Fig. 33. Oil saturations for 14 slices down the length of core RP-27E were averaged. Average oil saturations across the core, perpendicular to the bedding planes, are shown after waterflood and after chemical flood. It can be seen that the chemical flood reduced oil saturations in the core most in the interval between 14 and 23 mm, which is the interval shown by CT and minipermeameter measurement, to have the highest permeability.

However, flow patterns during reservoir flooding are predicted to be considerably different than those observed with small core plugs. One tracer test was conducted at the site with fluorescein. After tracer injection, no trace of fluorescein was found in produced fluids at adjacent wells. This indicates that, at least, there are not fractures that directly connect adjacent wells. Pressure fall-off tests are shown for two injection wells in Fig. 34. While these tests are not definitive, pressure fall-off occurred more rapidly than was expected.

Analytical information from three wells is sufficient to characterize an entire reservoir; however, sufficient information is available to identify the heterogeneities that exist vertically. The three cores (from Well J-4, H-4, and G-5) had remarkably complex, yet similar structures. It was not possible to identify individual layers that extend from well to well. The complexity of the layering and the angles of individual layers, which are not exactly parallel, indicate that individual sand bodies probably extend horizontally for only a few feet or tens of feet. Figure 11 shows an idealized model of how the reservoir is probably structured: complex layering with small compartments.

Previous laboratory experiments, conducted with outcrop samples of Tallant sandstone, have shown much better sweep by injected fluids in situations where the fluids must traverse through many small lenses of variable permeability similar to those in the Tucker sandstone (Tomutsa et al., 1993), and several field-scale waterfloods conducted in the Tucker sandstone were reported as successful (Powell, 1959). These are two additional reasons to expect that reservoir flow patterns are different from those observed with short core plugs, resulting in better sweep efficiency in the field than has been observed in laboratory floods conducted with short core plugs.

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TABLE 1. - Corefloods with field core from Hepler (KS) oilfield.

	K, mD	φ, %	Pore vol., mL	Orig. Soi	Before WF		Oil Produced, % PV		Recovery Efficiency, %		Information about coreflood		Well Depth, ft
					Soi	Sowf	Soef	WF	CF	Overall			No.
RP-25	Impermeable										Impermeable		J-4 576.6
RP-26	154.4	21.1	14.60	39.2	82	43	39.1	39	4.20	47.6	9.10	52.30 High Permeability Variation	J-4 581.1
RP-27	211	22.6	15.06	59	81	26.83	25.28	54.4	1.55	68.4	5.80	68.84 0.5% XP-100, 1.2% NaHCO ₃ , 0.45% STPP, 1200 ppm Alcoflood 1135	J-4 584.4
RP-27A	-	-	-	-	-	25.28	25.08	-	0.20	-	0.80	69.10 Same, but 2000 ppm Alcoflood 1135	
RP-27B	-	-	-	-	-	25.08	24.56	-	0.52	-	2.07	69.73 Same, but 2500 ppm Alcoflood 1135	
RP-27C	-	-	-	-	-	24.56	22.34	-	2.21	-	9.00	72.45 Same, but 3500 ppm Alcoflood 1135	
RP-27D	-	-	-	-	-	22.34	17.37	-	4.97	-	15.70	78.57 Same, but 5000 ppm Alcoflood 1135	
TOTAL RP-27	-	-	-	59	81	26.83	17.37	-	9.45	-	35.93	78.57 Cumulative RP-27A thru RP-27D	
RP-27E	-	-	-		64.7	32.2	23.43	32.53	8.76	50.28	27.21	63.82 0.1% CF-100, 3.2% NaHCO ₃ , 0.45% STPP, 1200 ppm Alcoflood 1135	
RP-28*	303.2	23.2	17.00	35.6	-	26.76	35.6	-	0.00	-	0.00	0.00 0.5% CF-100, 2.2% NaHCO ₃ , 0.45% STPP, 1200 ppm Alcoflood 1135 (note difference in Chem Formulation)	J-4 579.2
RP-29	28.2	17.81	12.14	39	39	27.3	22.9	11.7	4.40	30	16.00	41.20 Highly Laminated	J-4 579.5
RP-29R	-	-	-	-	72.68	30.65	3.24	42	27.41	57.83	89.43	95.54 0.5% CF-100, 2.2% NaHCO ₃ , 0.45% STPP, 1200 ppm Alcoflood 1135 Clean Core, resaturate, WF, same chem. slug except 5000 ppm polymer	
RP-30	175.7	21.87	14.74	41.04	41.04	-	40.23	-	0.81	-	1.98	1.98 0.5% CF-100, 2.2% NaHCO ₃ , 0.45% STPP, 3500 ppm Alcoflood 1135 CT Tracer Test indicates channeling	J-4 583.1
RP-31	170.5	21.1	14.11	46.35	-	-	43.09	-	3.26	-	7.03	7.03 0.5% XP-100, 2.2% NaHCO ₃ , 0.45% STPP, 1200 ppm Alcoflood 1135	H-4 586.5
RP-32	Impermeable											0.5% CF-100, 2.2% NaHCO ₃ , 0.45% STPP, 1200 ppm Alcoflood 1135	J-4 593.4
RP-33	Vertical imp												J-4 582.67
RP-34	192.0	21.6	14.88	36.81	36.81	-	33.79	-	3.02	-	8.22	8.22 0.1% CF-100, 3.2% NaHCO ₃ , 0.45% STPP, 1200 ppm Alcoflood 1135	J-4 578.6
RP-35	141.2	21.5	15.24	45.20	45.20	-	39.89	-	5.31	-	11.76	11.76 0.1% CF-100, 3.2% NaHCO ₃ , 0.45% STPP, 1200 ppm Alcoflood 1135	J-4 582.4
RP-36	36.4	20.0	14.31	48.78	48.78	-	37.95	-	10.83	-	22.20	22.20 0.1% CF-100, 3.2% NaHCO ₃ , 0.45% STPP, 1200 ppm Alcoflood 1135	J-4 590.3
*Chemflood before wf, no oil produced. Waterflood after chemflood at high frontal adv. rate.													
Orig. Soi (%PV) is the original field oil saturation for the core plug. Sowf and Soef are, respectively, the oil saturations after waterflood and chemical flood.													
Recovery efficiency is the volume of oil produced by the recovery process / volume of oil remaining in the core at the beginning of the process x 100.													
STPP is sodium tripolyphosphate. CF-100 and XP-100 are Chevron surfactants. Alcoflood 1135 is an Allied Colloids polyacrylamide polymer.													

TABLE 2 - Results of Routine Laboratory Waterflooding Tests

Sample	1	2	3	4	5	6	7	8	Average 8 plug samples	Average 3 radial samples
Oil saturation, % PV	20	40	48	65	50	46	56	53	51.2	52.3
bbl/acre-ft	230	642	715	978	869	582	951	855	799	807
Oil Recovery, % PV	0	9	20	30	18	10	20	16	17.7	21.8
bbl/acre-ft	0	145	298	452	313	126	340	258	276	336
Residual Oil, % PV	20	31	28	35	32	36	36	37	33.6	30.5
bbl/acre-ft	230	497	417	526	556	456	611	597	523	471
K_w at S_{Or}^1 , mD	4.9	2.7	23.3	27.7	11.0	0.33	10.7	1.2	11.0	
Pressure at initial fluid production, psi	10	10	15	10	15	30	15	20		
End Point WOR ²									15000	4000

1-Permeability to water at residual oil saturation.

2-Water:oil ratio.

TABLE 3 - Coreflood RP-27E effluent measurements

Volume injected, %PV	Oil saturation, %PV	Incremental oil, mL	WOR	Comments
0	64.73			
0.21	53.44	1.70	1.83	Begin waterflood
0.31	46.14	1.10	1.38	
0.41	43.88	0.34	4.47	
0.61	41.82	0.31	9.82	
1.02	38.17	0.55	11.07	
1.42	35.18	0.45	13.52	
1.82	33.52	0.25	24.34	
2.23	32.20	0.20	30.43	End waterflood Begin chemflood
2.44	31.87	0.05	65.07	
2.56	30.87	0.15	11.65	
2.65	29.54	0.20	7.00	
2.74	28.88	0.10	12.95	
3.00	27.22	0.25	16.03	
3.29	26.22	0.15	28.98	
3.40	24.89	0.20	8.01	
3.78	23.57	0.20	27.49	
4.07	23.43	0.02	231.22

FIGURE 3. - Well H-4 wireline logs.

FIGURE 4. - Well H-4 permeability.

FIGURE 5. - CT derived permeability, Well H-4.

FIGURE 6. - Wireline logs and CT scan, Well H-4.

FIGURE 7. - Petrographic image, depth 581.1 ft, well J-4.

FIGURE 8. - Minipermeameter schematic.

FIGURE 9. - CT porosity and permeability contrast, depth 581.1 ft, well J-4.

FIGURE 10. - Permeability distribution, depth 583.1 ft, well J-4.

FIGURE 11. Idealized model of Tucker sandstone.

FIGURE 12. CT tracer test.

FIGURE 13. - Core plug face permeability.

FIGURE 14. - Water-oil ratio for linear and radial corefloods.

FIGURE 15. - Permeability of core plug RP-27 across end faces.

FIGURE 16. - Wettability measurements, well H-4, depth 584.9 ft.

FIGURE 17. - Effluent analysis, coreflood RP-27E.

FIGURE 18. - Effluent analysis, coreflood RP-36.

FIGURE 19. - Core plug RP27E porosity.

FIGURE 20. - Injection of a 0.3 PV slug of untagged brine.

FIGURE 21. - Core plug RP-27E oil flood.

FIGURE 22. - Core plug RP-27E oil saturation after oil flood.

FIGURE 23. - Core plug RP-27E waterfood.

FIGURE 24. - Core plug RP-27E oil saturation after waterflood.

FIGURE 25. - Chemical flood, core plug RP-27E, 0.1 and 0.2 PV.

FIGURE 26. - Chemical flood, core plug RP-27E, 0.3 and 0.4 PV.

FIGURE 27. Chemical flood, core plug RP-27E, 0.5 and 0.6 PV.

FIGURE 28. Chemical flood, core plug RP-27E, 2.6 and 11.2 PV.

FIGURE 29. - Core plug RP-27E oil saturation during chemical flood, 0.3PV.

FIGURE 30. - Core plug RP-27E oil saturation during chemical flood, 0.4PV.

FIGURE 31. - Core plug RP-27E oil saturation during chemical flood, 2.62 PV.

FIGURE 32. - Core plug RP-27E oil saturation after chemical flood.

FIGURE 33. - Oil saturations before and after chemical flood, RP-27E.

FIGURE 34. - Pressure falloff tests.

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