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Application of Polymer Gels for Profile Modification and Sweep Improvement of Gas Flooding

Topical Report

By
Clarence Raible
Tao Zhu

December 1992

Performed Under Cooperative Agreement No. FC22-83FE60149

IIT Research Institute
National Institute for Petroleum and Energy Research
Bartlesville, Oklahoma

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U. S. DEPARTMENT OF ENERGY
Bartlesville, Oklahoma

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APPLICATION OF POLYMER GELS FOR PROFILE MODIFICATION AND SWEEP IMPROVEMENT OF GAS FLOODING

By Clarence Raible and Tao Zhu

ABSTRACT

Early CO_2 breakthrough can be a serious problem during miscible and immiscible CO_2 flooding of reservoirs with heterogeneous formations. One potential method to reduce the problem of gas channeling is the use of a gel to restrict flow of fluids into the high-permeability zones. This study included evaluation of several different candidates for their potential as gelled polymer treatments for in situ profile modification. Crosslinking of one gel system (melamine resin-xanthan polymer) was activated in the pH range of 4 to 5. This method depended upon CO_2 contacting reservoir brines to form carbonic acid. For a CO_2 gas flood, brines contacted by CO_2 will have a lower pH than the reservoir brine. The primary disadvantages of the melamine resin-gel system were the high sensitivity of the gel to shear and the inability of the gel to reheal because the resin degraded after the resin activation in acidic brines.

Another gel system was evaluated which was a blend of hydroxypropyl cellulose (HPC) and sodium dodecyl sulfate (SDS). A gel was formed by increasing the salinity of the polymer/surfactant blend. This gel had the advantage of not requiring a crosslinking agent such as a heavy metal compound and did not require any specific solution pH to form a gel. However, because the gel formed immediately upon increasing salinity, the gel could be placed only a short distance from the point of injection. This gel system did not appear to be a practical method for profile modification because of the inability for deep penetration and placement of the HPC/SDS solutions in the reservoir. Also, brine injection following gel placement produced an increase in the sandpack permeability. This demonstrated that the gel was not stable to subsequent brine flooding.

The objective of gel treatments is to restrict flow through fractures and high permeability zones without significantly damaging the adjacent oil productive zones. This involves injection of viscous polymer solution, hopefully into a high-permeability zone. In this study, layered sandpacks were used to show the effect of gelant mobility on gel penetration and placement. X-ray computerized tomography (CT) was used to visualize the flow path of the injected gelant and the location of gel placement. A conventional gel of xanthan and Cr(III) as a crosslinking agent was used for experimental model studies. The results of experimental model studies demonstrated the effects of viscous crossflow which may damage the oil productive strata. More specifically these studies of layered models showed that unless there is a very high-permeability contrast, such as a

fractured zone, a considerable volume of viscous crossflow will occur with damage to oil productive strata. These results indicated the need for injection and placement of a low viscosity gelant prior to gelation.

This report covers work performed for Task 5 of Project BE5B as described in the Annual Research Plan for FY92 under cooperative agreement DE-FC22-83FE60149 with the Department of Energy.

INTRODUCTION

Many CO_2 projects have experienced early gas breakthrough because of fractures, high-permeability zones, and other reservoir heterogeneities. These factors adversely affect sweep efficiency, and a considerable portion of the oil remains in the reservoir because lower permeability oil-bearing zones are often bypassed by the gas flood. For more efficient oil recovery, profile modification and improved mobility control are required to reduce channeling through higher permeability zones.

Water-soluble polymers and gel treatments are widely used to reduce fluid flow in thief zones. For waterflooding, crosslinked polyacrylamide and biopolymers have been used for profile modification. Polymer gels which are sufficiently stable and rigid can potentially reduce the problem of gas channeling by restricting flow of fluids and lower the high-permeability zone. For the crosslinked polymers to properly block high-permeability zones, chemical and polymer injections must be carefully designed so that polymer gelation occurs in thief zones without damaging oil-productive zones.

The development of gel technology continues to be a subject of considerable research to improve sweep efficiency of enhanced oil recovery applications. A number of technical restraints on gel technology require further research to achieve the full potential of gels for oil recovery applications. These technical restraints[1] include the limited control of the time for which gelation occurs, the limited control on gel placement without damaging the oil productive reservoir, and the limited stability of gels formed under high salinity and temperature conditions.

The objective of this work was to develop gel systems which are applicable to CO_2 gas flooding conditions, and to conduct laboratory experiments to demonstrate the potential for selective placement of gels for profile modification. In this study, we evaluated several types of gels for their potential as profile modification agents for CO_2 applications. We also examined some of the constraints and limitations on controlling where the injected gelants are placed in the reservoir using experimental models.

POLYMER GEL STUDIES

A polymer system which has the potential to meet the conditions for applications of CO_2 gas floods at weak acid conditions in the pH range of 4 to 5 was investigated.[2] An essential part of

this method depends upon CO_2 contacting reservoir brines to form carbonic acid. For a CO_2 gas flood, brines contacted by CO_2 will have a lower pH than the reservoir brine. It may be possible to use this property of CO_2 gas floods to selectively form and crosslink stable polymer gels in areas of gas channeling. The selective placement of a rigid gel may be accomplished by injection of a polymer and crosslinking compound into an oil reservoir. Upon entering a gas channel, the lower pH of the brine activates the crosslinking compound to produce a firm polymer. This polymer system used xanthan gum as the polymer and a melamine resin as a crosslinking agent.

Another gel system which does not require a crosslinking agent was investigated. Whittington and Naae[3] reported a blend of hydroxypropyl cellulose (HPC), and sodium dodecyl sulfate (SDS) will form a gel when mixed with brine. The gel was formed by increasing the salinity of the blend. The amount of salt in the solution controlled the formation of mixed micelles where the SDS surfactant strongly binds to the HPC polymer. This gel had the advantage of not requiring a crosslinking agent such as the melamine resin or a heavy metal. In addition, the gel did not require any specific solution pH to form a gel.

Materials for Melamine Resin Crosslinking

The melamine resin (hexamethyl melamine) was obtained from American Cyanamid, Inc. and the product is sold by the tradename Cymel® 303. The alkylated melamine resin has limited solubility in aqueous solutions. A number of cosolvents were tested to find a suitable resin solvent. Solubility tests were conducted with a number of alcohols. Of these alcohols, the resin was most soluble in isopropyl alcohol. The resin then could be dispersed in brine solutions after dissolving the resin in isopropyl alcohol. Surfactants also were effective agents for dissolving the resin in brine solutions. An ethoxylated sulfonate Neodol® 25-3S from Shell Chemical Company was used for these studies. This surfactant was 58% active surfactant. The melamine resin was assumed to be 100% active resin. The concentration used to prepare test solutions was 0.58 parts surfactant to 1.0 part resin by weight.

The polymer was Flocon 4800C® biopolymer provided by Pfizer with a concentration of 16.35% xanthan gum. Test solutions of the polymer were prepared by weight using a high speed blender. For these preliminary tests, high pressure CO_2 was not used to reduce the pH of polymer/resin solutions because of the experimental difficulties in observing the solution properties. The pH of solutions was adjusted with acetic acid.

Bottle Tests with Melamine Crosslinking with Xanthan Polymer

A number of experimental tests were conducted to determine if a firm stable gel could be made by polymer crosslinking at the gas flooding conditions. Screening tests were made for different polymer and resin concentrations, solution pH, temperature, and salt concentration of the brine. Bottle tests were used to observe gel formation and gel properties.

The resin was activated by acidic conditions causing the resin to react with the xanthan polymer and form a gel. A number of polymer/resin solutions were made by adjustment of the initial pH with acetic acid. These solutions were made with different pH values ranging from 3 to 5. The pH of the polymer/resin solution changed the rate of gel formation. At room temperature, gels were formed more quickly in solutions with a lower pH. Although gel formation required longer time periods of several days to several weeks, stable gels were made with solutions initially adjusted to as high as a pH of 4.5. The tests demonstrated that gels can be formed with solutions in the pH range of 4 to 4.5. This is within the pH range expected for some reservoir brines saturated with CO_2 at high pressures. The time for gel formation also depended upon other variables such as temperature and polymer/resin concentrations.

Experimental tests were conducted to determine the effect of temperature on gel formation. A series of polymer/resin solutions were heated at temperatures of 75°, 100°, 120°, and 170° F (23.9°, 37.8°, 48.9°, and 76.7° C). The time required to form gels was much faster at the higher temperatures. At 170° F (76.7° C), gels were formed in less than 1 hour; however, only solutions with high resin concentrations formed gels. Also, resin precipitation was indicated by a change in the solution to a white or milk colored solution. The higher temperatures caused the color of the solutions to change more rapidly. At other temperatures, gels were formed more quickly at 120° F (48.9°C) than at 75° and 100° F (23.9 and 37.8° C). The solution temperature changed both the time of gel formation and the rate of resin precipitation.

Other tests were made which indicated the resin precipitated with time after the resin was hydrolyzed in acid solutions. Solutions of melamine resin were initially adjusted with acetic acid to a pH of 3, 3.4, and 4. Two sets of these solutions were made in brines of 2 and 12% NaCl. The solutions contained a high resin concentration of 6,700 ppm. After preparing the resin solutions, the pH of the solutions was monitored as a function of time at 75° F (23.9° C). The results for the 12% NaCl brine are shown in Fig. 1. As the resin hydrolyzed with the acid, the pH of the solutions increased by about 0.5 pH units in 24 hours. About the same pH change with time was measured for the 2% NaCl brine solutions. It was noted that the resin solutions formed a white precipitate as a function of time. More of the precipitate was formed in the lower pH solutions. The experiments indicated that the resin degraded after the resin was hydrolyzed at a pH of 3 to 5. Also, resin precipitation appeared to be greater in the lower pH solutions. There was no evidence that the rate of precipitation changed in brine concentrations of 2 and 12% NaCl.

Other experiments indicated the hydrolyzed resin degraded with time. A solution of 6,700 ppm resin was initially adjusted with acetic acid to a pH of 4.0. The temperature of the resin solution was maintained at 75° F (23.9° C). At different times, portions of the resin solution were mixed with polymer to obtain solutions with 5,000 ppm each of polymer and resin. The polymer

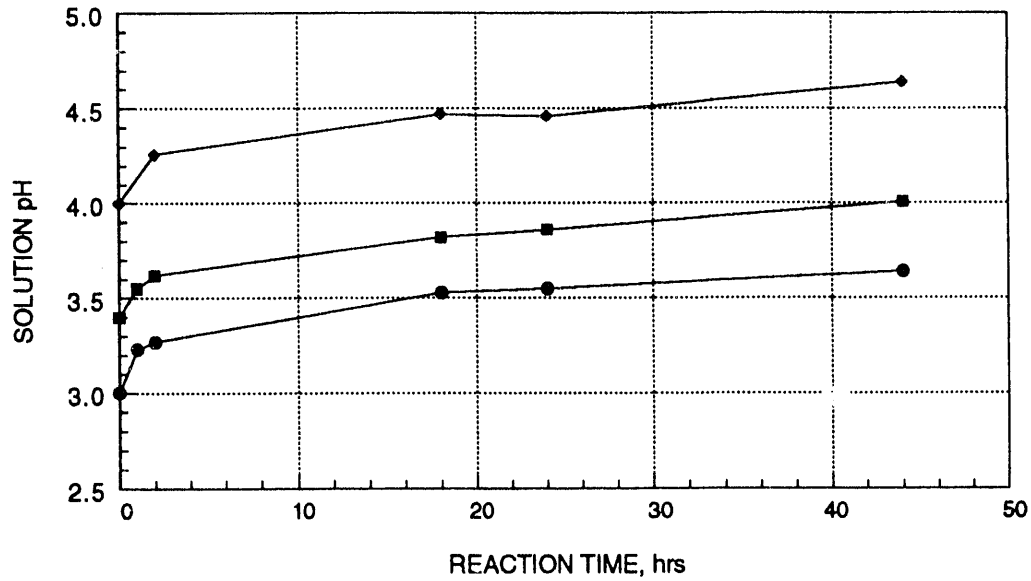

FIGURE 1. - The change in pH of melamine solutions in 12% NaCl brine as a function of time.

and resin mixtures made within 6 hours of resin activation formed firm gels in less than 16 hours at 120° F. Polymer/resin mixtures of the same concentrations made from resin activated for 30 hours formed weak gels only after extended time periods of one week at 120° F (48.9° C). The tests indicated that even at initially high resin concentrations the activated resin precipitated with time until there was insufficient active resin present in solution to form a firm gel.

A series of polymer/resin solutions were made with polymer concentrations of 400, 500, 625, 1,250, and 1,500 ppm. Each solution contained an excess of resin crosslinker (4,500 ppm) sufficient to form a gel. At 120° F (48.9° C), the gels formed for each solution varied in consistency from very soft to a firm gel. The solution with the 625 ppm concentration of polymer produced a very soft gel which was formed in less than 24 hours. The solutions containing 400 and 500 ppm polymer formed small gel particles suspended in the solution but the entire solution was not gelled. Also, these solutions required several days for the suspended gel particles to form. The 1,250 and 1,500 ppm polymer solutions formed medium and firm gels respectively. The experiments indicated the lower limit for polymer concentration to produce a gelled solution was over 600 ppm of polymer. However, stronger and more stable gels were formed with polymer concentrations greater than 1,250 ppm.

A limited number of tests were made with high pressure CO_2. The object was to determine if solutions saturated with CO_2 would reduce the solution pH sufficiently to activate the resin and produce a crosslinked gel. Tests were made by placing polymer/resin solutions in a high pressure

vessel with CO_2 pressures of 600 to 800 psi (4.14 to 5.52 mPa). The gels were shear sensitive. This presented problems in observing formation of gels at high pressures. Upon releasing the CO_2 pressure, the solutions boiled and outgassed because of the absorbed CO_2. Because of shear sensitivity of the gels, release of CO_2 pressure and solution outgassing probably caused break-up of the gels. However, there was some evidence that gels were formed. The solutions had increased in viscosity and the color of the solutions had changed to a white color. As observed previously, a change in solution color indicated resin activation which should have resulted in polymer crosslinking and formation of a gel. Results of this study indicated solutions saturated with CO_2 were sufficient to reduce the solution pH which would activate the resin and produce crosslinking.

An important feature of any gel is the ability of a gel to reheal after gelation. This was a disadvantage of this melamine resin-gel system. The gel was shear sensitive causing breakup of the gel. In addition, the resin precipitated after activation in acidic solutions. After the gel was subjected to shear conditions, sufficient active resin was not present to allow the polymer to reheal crosslinking bonds and recover the original gel viscosity.

Materials for HPC/SDS Gels

Whittington and Naae[3] reported a blend of hydroxypropyl cellulose (HPC) and sodium dodecyl sulfate (SDS) will form a gel when mixed with brine. The gel was formed by increasing the salinity of the polymer/surfactant blend. This gel has the advantage of not requiring a crosslinking agent such as a heavy metal. In addition, the gel does not require any specific solution pH to form a gel. The HPC polymer was obtained from Aqualon Company which markets the polymer under the trade name Klucel.® A high-molecular-weight and viscous grade of the product (Klucel H) was used for this study. The SDS surfactant was a chemically pure grade of SDS (99%). The brines were made with reagent grade NaCl.

Bottle Tests with HPC/SDS Gels

Gels were formed by mixing solutions of HPC and SDS with brine. All solutions were prepared with equal weight of the HPC polymer and SDS surfactant. Figure 2 shows the room temperature (24° C) viscosities of several HPC/SDS solutions measured before the addition of salt. For a solution containing 0.5% HPC and 0.5% SDS, the viscosity measured at room temperature with a Brookfield cone and plate viscometer was 128 cP at a shear rate of 2.25 sec^{-1}.

The effect of increasing brine concentration is shown in Figs. 3 and 4. Viscosity measurements were made with a series of solutions containing 0.5% HPC and 0.5% SDS and increasing the salinity concentrations. Lower viscosity solutions containing 0.0 to 1.0% NaCl were measured with a cone and plate Wells-Brookfield viscometer. For higher viscosity solutions containing salt concentrations greater than 1.0% NaCl, viscosity measurements were made with a

number 3 or a number 4 cylindrical spindle using a Brookfield Model LVS viscometer. As shown in Figs. 2 and 3, the solution viscosity increased with higher salt concentrations. Although stable

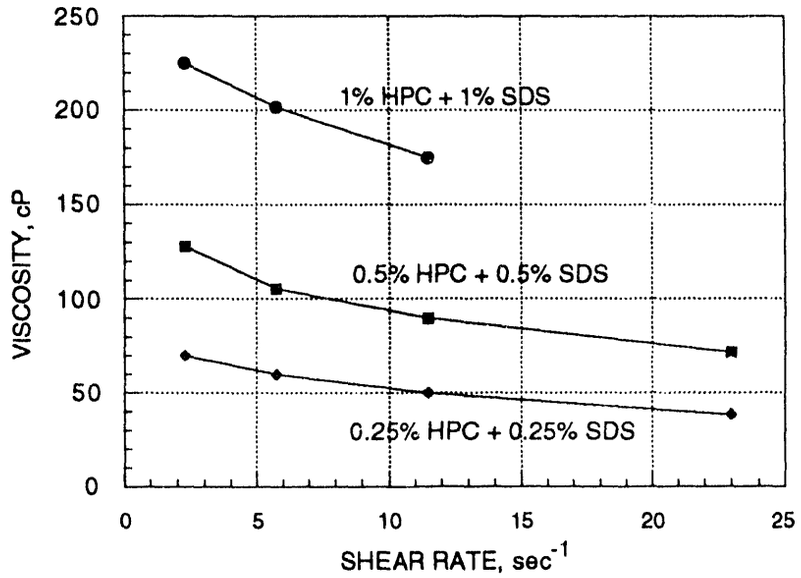

FIGURE 2. - Measured viscosities of fresh aqueous solutions with equal concentrations of HPC and SDS.

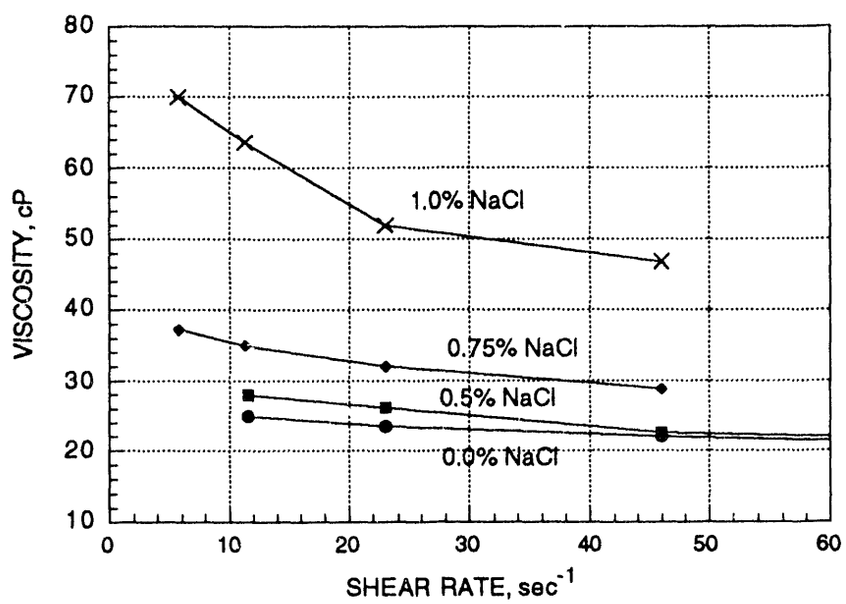

FIGURE 3. - Room temperature (24° C) viscosities of polymer solutions (0.5% HPC and SDS) with brine concentrations ranging from 0.0 to 1.0% NaCl.

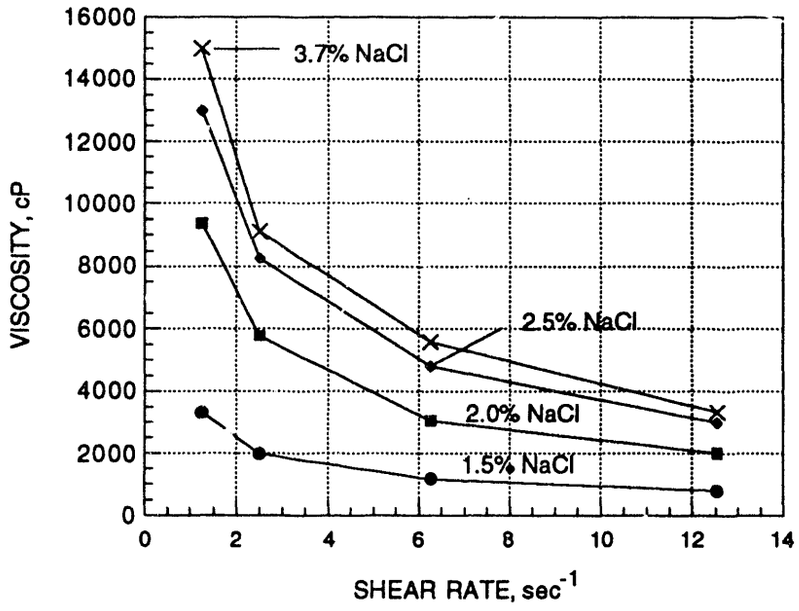

FIGURE 4. - Room temperature (24° C) viscosities of polymer solutions (0.5% HPC and SDS) with brine concentrations ranging from 1.5% to 3.7% NaCl.

gels were obtained with higher salt concentrations, solution viscosities with salt concentrations greater than 3.5% NaCl resulted in no measurable increase in gel viscosity.

Other experiments were made to determine the effect of polymer concentrations on solution viscosity. Figure 5 shows the change in viscosity of gels containing 3.5% NaCl with polymer and surfactant concentrations up to 0.5% HPC at room temperature. For gels with concentrations of HPC and SDS between 0.25 and 0.5%, the increase in gel viscosity was approximately proportional to the polymer and surfactant concentrations. The gel containing 0.5% HPC and SDS was about 15,000 cP at a shear rate of 1.25 sec^{-1}. Higher gel viscosities are possible with solutions containing higher concentrations of HPC polymer. However, there is a practical limit for polymer concentration in field applications because of the high solution viscosity and problems with solution injectivity into the reservoir.

Profile Modification with Sandpacks and HPC/SDS Gels

For initial profile modification tests, it was observed that gel was deposited on the inlet injection screen (300 mesh). Although gel deposition on the screen demonstrated the capability of the gel to plug large sized pores, the gel effectively plugged the screen and interfered with permeability measurements. Formation of a gel in the inlet system was reduced by redesigning the injection system to minimize dead volume. This resulted in less solution mixing and gel

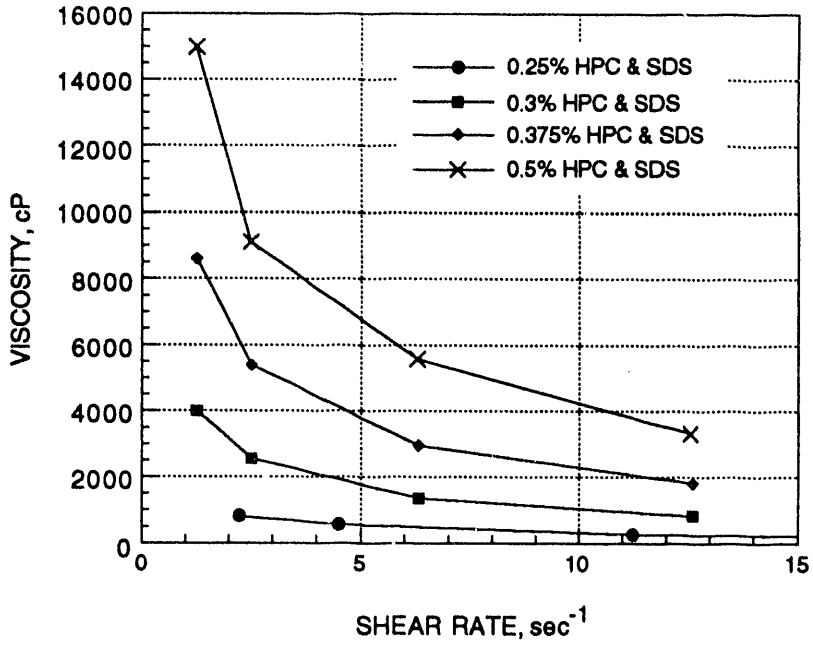

FIGURE 5 - Viscosity at room temperature of gels with 3.5% NaCl brine and different concentrations of HPC and SDS.

formation in the injection system. Also, premature gel formation in the inlet system and screen plugging was reduced by chasing each of the polymer/surfactant and brine slugs with small quantities of deionized water (0.01 PV). These steps eliminated gel deposition on the inlet screens.

Profile modification tests using the HPC/SDS gel were made with sandpack floods. For these tests, alternating slugs (0.05 PV) of 1% polymer/surfactant solution and a 7% brine were injected into a sandpack. A total of about 0.3 PV of the polymer/surfactant solution was injected. The strategy was to promote intimate mixing of the two solutions to form a gel. Injection rates were maintained at a constant flow rate of 0.7 m/d and the differential pressure across the sandpack was monitored as a measure of changes in the sandpack permeability. Although the resistance factor after gel treatment was typically 200, examination of sandpack indicated the gels were largely located near the inlet section of the sandpack. Because the gel formed immediately when the HPC/SDS solution was mixed with brine, the gel plugged the sandpack only a short distance from the inlet.

For profile modification treatments, the gel must be placed at some distance away from the wellbore in high-permeability channels. Various strategies, including displacement with slugs of fresh water, were used to place the HPC/SDS solution away from the sandpack inlet prior to brine contact and gel formation. However, fresh water displacement effectively reduced the gel resistance factor presumably because of dilution of the HPC/SDS solution. Also, a 1% SDS

surfactant solution in fresh water was used as a displacement fluid for the HPC/SDS slug. The SDS surfactant slug then was followed by a high concentration brine to contact the HPC polymer and form a gel. However, the brine caused precipitation of the surfactant when the brine exceeded 3% NaCl. This was demonstrated by both sandpack flow and bottle tests. Using SDS in fresh water as a displacement fluid also caused the HPC polymer to become phase unstable. The HPC polymer will precipitate from brine solutions without the SDS surfactant. The effluent from sandpack flow tests initially contained precipitated SDS surfactant followed by precipitated HPC polymer.

Additional bottle tests were made with several ethoxylated cosurfactants in an attempt to stabilize and overcome the problems associated with SDS surfactant precipitation and to improve HPC/SDS gel stability. Also, the presence of divalent cations (Ca^{2+} and Mg^{2+}) will cause precipitation of anionic surfactants such as the SDS surfactant. As discussed previously, the precipitation of the SDS surfactant can cause the HPC polymer to precipitate. Tests were made with an ionic ethoxylated cosurfactant (Neodol 25-3S) to improve salt tolerance of the solutions. For a solution containing 0.5% SDS and 0.3% Neodol 25-3S as a cosurfactant, the salt tolerance was increased to nearly 9% NaCl. Small quantities of precipitate were observed with 9% NaCl at a temperature of 24° C. This was an improvement in SDS salt tolerance from 3% NaCl without the cosurfactant.

Other tests were made to determine the effect of the ethoxylated cosurfactant on HPC/SDS gel properties. Solutions of 0.5% HPC and 0.5% SDS were prepared with 0.17% Neodol 25-3S in various brine concentrations. For previous gel tests without a cosurfactant, a maximum gel viscosity was obtained with 3.5% NaCl. No further improvement in gel viscosity was measured for gels containing higher brine concentrations. The addition of the cosurfactant (Neodol 25-3S) produced solutions with lower viscosities. A gel was not formed with 3.5% NaCl. Only a small increase in solution viscosity was measured. Solutions containing the cosurfactant and higher concentrations of brine (5 to 10% NaCl) formed weak gels and the viscosity was lower than that of gels without the cosurfactant.

Another problem was noted with the cosurfactant gel system. Gels samples heated to 50°C degraded with time. At the higher temperature, this was indicated by the formation of a white precipitate and a reduction in viscosity. Also, the rate of gel degradation increased for gels containing higher brine concentrations. Another nonionic ethoxylated surfactant (Neodol 91-2.5) was used as a potential cosurfactant candidate for increasing salt tolerance of the gels. This cosurfactant improved salt tolerance of the SDS surfactant solutions, but gels were not formed when combined with the HPC polymer. A small improvement in solution viscosity was measured with brine concentrations up to 5% NaCl. A fibrous precipitate was formed for solutions containing concentrations greater than 5% NaCl.

These tests indicated that the addition of an ethoxylated cosurfactant resulted in either gels with lower viscosities or unstable gel mixtures. The use of an ethoxylated cosurfactant does not appear to be a satisfactory method for improving salt tolerance of the HPC/SDS gels.

In summary, the experimental results show that the HPC/SDS gel can be formed by the injection of suitable brines and HPC/SDS solutions. However, because the gels form immediately when the HPC/SDS solutions are mixed, gel plugging extends only a short distance from the point of injection. This gel system does not appear to be a practical method for profile modification because of the inability for deep penetration of the HPC/SDS solutions in the reservoir. Also, after gel placement, brine flow through the gel increased the sandpack permeability, and the gel resistance factor decreased. This demonstrated the gel was not persistent or stable to subsequent brine flooding.

Bottle Tests with Cr(III)/Xanthan Gels

Another part of this study was the use of laboratory models to investigate selective placement of gels. In particular, experimental models were used to demonstrate the potential for gel placement in heterogeneous layered strata. Therefore, a gel system was required to be used with experimental model studies. A conventional crosslinked gel system which would meet the requirements for use with experimental models was chosen. Screening tests were performed with this gel system to determine the conditions for gelant injection, the gelation time, and gel properties.

The gel system to be used with experimental model studies was xanthan polymer and Cr(III) as a crosslinking agent. The xanthan polymer (Flocon® 4800C) was a concentrated broth with an active biopolymer concentration reported by Pfizer to be 16.35%. In this report, the polymer concentrations were reported using the manufacturer's assay. Chromic chloride used as the Cr(III) crosslinker was purchased from Fisher Scientific. Solutions of the biopolymer and chromic chloride were prepared in a stock brine with a concentration of 6.6% NaCl, 1.5% $CaCl_2$, and 0.5% $MgCl_2$. After mixing the stock solutions, the polymer solutions were adjusted with dilute HCl and NaOH to obtain the desired pH.

The viscosities of polymer solutions were measured with a Brookfield viscometer Model LVT-CP. Viscosities of solutions with different polymer concentrations were measured over a shear-rate range of 1.15 to 230 sec^{-1}. Figure 6 shows the linear plot of shear thinning rheograms for polymer concentrations of 1,000, 1,500, and 2,250 ppm. A regression of the viscosity and shear data was made for each polymer concentration using the power law model in Eq. 1:

$$\mu = K\gamma^{n-1} \qquad (1)$$

The power law constants (K and n) of the viscosity and shear data are listed in Table 1.

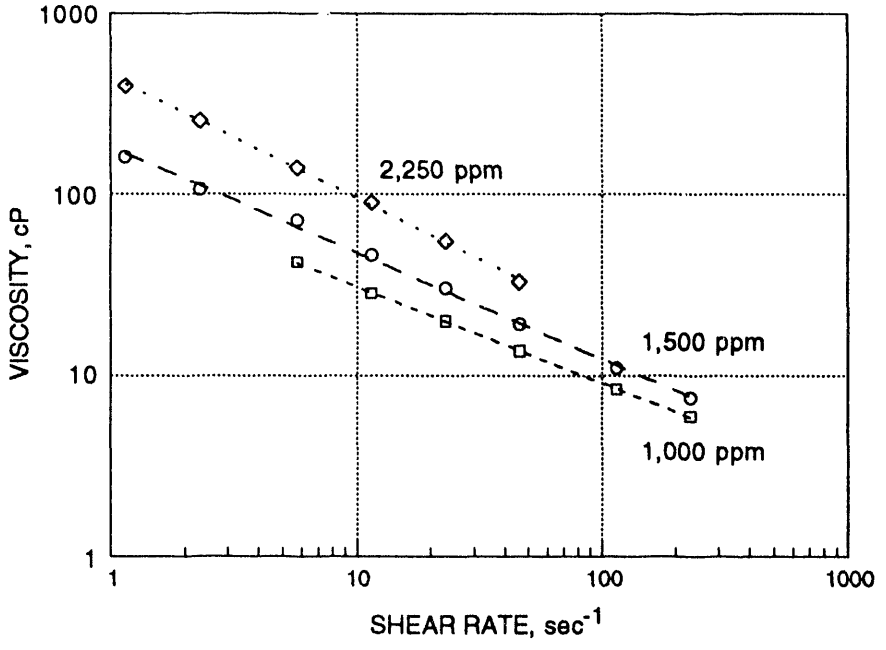

Figure 6. - Effect of shear rate on viscosity of xanthan solutions.

TABLE 1

Power Law Parameters of 1,000 and 1,500 ppm Xanthan

Concentration ppm	n	K cP^n
1,000	0.467	106
1,500	0.417	182
2,250	0.330	445

These shear and viscosity results were compared with a report by Hejri, et. al.[4] where active biopolymer concentrations were based on isopropanol precipitation. The biopolymer concentration reported by the manufacturer was 1.5 times higher than the concentration measured by precipitation. The lower value for polymer concentration by precipitation was used in Hejri's report. Good agreement which was within the experimental error of the viscosity measurements was found for polymer viscosity and shear data. As shown in Table 1, for a polymer concentration of 1,500 ppm, the regression parameters were n = 0.417 and K = 182. Hejri reported values of 0.418 and 181 for the regression parameters at a comparable concentration of

1,500 ppm based on the manufacturer assay. Hejri developed correlations and an empirical models to predict the apparent viscosity of xanthan solutions polymer solutions flowing through sand packs. Later in this report, these regression models were used to predict the apparent viscosity of polymer solutions used in experimental models.

Gelation Rate of Cr(III) and Xanthan Polymer

The rate of gelation and gel strength were measured by observation of the samples according to the properties described in Table 2. The gel descriptions are similar to those reported by Sydansk.[5] Although the gel strength descriptions are subjective observations, the bottle tests provided a qualitative method for rapid screening of the gel formulations. The pH of the solutions was an important variable which controlled both the rate of gelation and precipitation of chromium. Samples adjusted to a pH of 5.5 resulted in chromium precipitation. These experiments indicated that before gelation this gel system can be applied only when the gel solutions do not exceed a pH of about 5.0.

Some of the results of gel bottle tests are presented in Table 3. These results also are shown in Figs. 7 and 8 where the gel descriptions of Table 3 were assigned arbitrary values for viscosity. The lowest viscosity description of the gel solution (A) was assigned a value of one; the highest viscosity (H) was assigned a value of 8. As shown in Table 3 and Fig. 7, faster gelation rates were observed as the pH of the gel solutions increased from 4.0 to 5.0. Table 3 and Fig. 8 show the effects of Cr(III) concentration where higher chromium concentrations increased the rate of gelation. Thus, gelation rates may be varied by changing the polymer and Cr(III) concentrations, and pH of the solutions.

TABLE 2

Physical Description of Gel Strength for Xanthan Polymer and Cr(III) Crosslinker Solutions

Gel Strength Code	Description of Gel Strength
A	No gel formed. The gel appears same viscosity as the original polymer solution.
B	Highly flowing gel. The gel appears to be only slightly more viscous than the initial polymer solution.
C	Flowing gel. Detectable gel with the gel rapidly flowing to the bottle cap upon inversion.
D	Moderately flowing gel. Gel does not readily flow to the bottle cap upon inversion.
E	Barely flowing gel. Gel slowly flows to the bottle cap upon inversion.
F	Highly deformable nonflowing gel. Gel readily deforms but does not flow upon inversion.
G	Slightly deformable nonflowing gel. Gel surface slightly deforms upon inversion.
H	Rigid gel. No gel surface deformation upon inversion with gel syneresis.

TABLE 3

Reaction Time and Physical Description of Gels with 2,000 ppm Xanthan Polymer and Various Cr(III) Crosslinker Concentrations

Solution pH	Reaction Time hrs	Cr(III) Concentration 25 ppm	50 ppm	75 ppm	100 ppm
4.0	1	A	A	A	A
	8	A	A	A	A
	24	A	A	B	C
	48	A	B	B	C
	96	A-B	C	C	F
	192	B	C	C	F
	312	C	C	C-D	F-G
4.5	1	A	A	A	A-B
	2	A	A-B	A-B	B
	4	A-B	C	D	E
	8	B	E	F	F-G
	24	E	F-G	G	G
	48	F	F-G	G	G
	96	F	G-H	G-H	G-H
	192	G	G-H	G-H	G-H
5.0	0.5	A	A-B	C	D
	1	B	B-C	D	E
	2	C	E	F	F
	4	C-D	F	G	G
	8	C-D	F-G	G	G
	24	E	G	G	G
	48	F	G	G-H	G-H
	96	F	G-H	G-H	G-H
	192	G	H	H	H

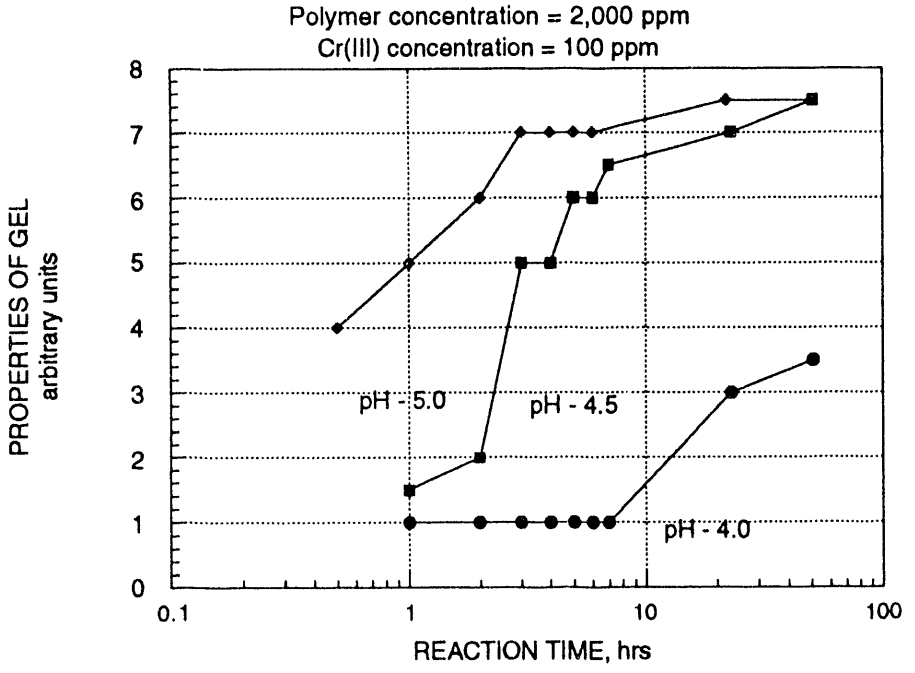

FIGURE 7.- Gel properties and reaction time of 2,000 ppm xanthan and 100 ppm Cr(III) solutions with initial pH values of 4, 4.5 and 5.

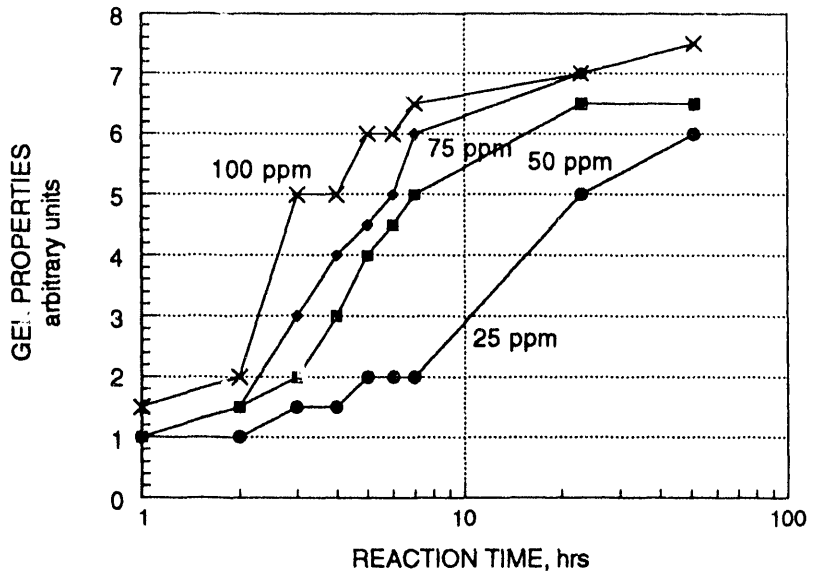

FIGURE 8. - Gel properties and reaction time of 2,000 ppm xanthan solutions with an initial pH of 4.5 and various concentrations of Cr(III).

Other tests were made to show the effect of the porous media sandpacks on gelation rates. A series of gelant samples was prepared in brine with 1,000 ppm xanthan and 100 ppm Cr(III). The initial pH of this mixture was 3.45. Silica sands used for sandpack experiments and other sands prepared from crushed rocks were added to each test sample. The quantity of sand added to each sample was equal to 20 % of the liquid weight. A limited quantity of sand was used to allow observation and measurement of the properties of the liquid solution. Actually, for a gelant flowing through a porous sandpack, the fluid volume would occupy only the pore volume of the sand. Although the quantity of the test liquid was substantially greater than the sand pore volume, the tests were made to show the relative changes in fluid properties produced by different sands. Each gel solution was mixed slowly with a magnetic stirring bar for several hours after addition of the sands.

Figure 9 shows the pH changes of the gel solutions resulting from different sands. The limestone mixture increased rapidly to a pH of nearly 6, a value that would cause precipitation of chromic ions which would inhibit gel crosslinking. There was no evidence of gel formation. Also, the polymer appeared to adsorb onto the limestone particles resulting in polymer agglomeration with the sand. Because of the high capacity of a limestone matrix to neutralize the Cr(III)/biopolymer solution, it was unlikely a gel would be formed in a carbonate matrix even with a highly buffered gel system. Thus, the Cr(III)/biopolymer system would not be effective as a mobility control agent for reservoirs with large quantities of reactive carbonate minerals.

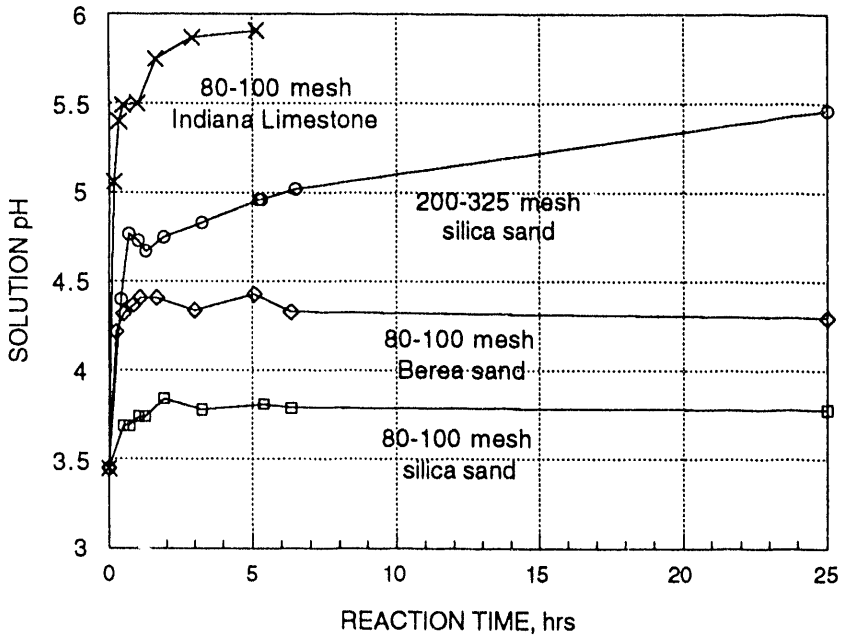

FIGURE 9. - The pH of 1,000 ppm xanthan and 100 ppm Cr(III) solutions with various sand mixtures.

Initially, with the 80-100 mesh silica sand, the solution pH increased to about a pH of 4. After 1 day, a weak gel was formed and the solution pH remained constant at a pH of 3.8. The crushed Berea sand increased the solution pH one pH unit. After 1 day, a firm gel was formed and the solution pH remained constant at a pH of 4.3. The quantity of clays in the porous media can affect the gelation rates because of competition between the biopolymer and clays.[6] For this experiment, the effect of clays was probably not significant because of the low cation-exchange-capacity of the Berea sand[7] and high concentration of Cr(III).

After 5 hours with the 200-325 mesh sand, the solution pH increased to about 5, and a weak deformable gel was formed. After 1 day, the solution pH had increased to a nearly 5.5; a value which would inhibit further gelation. In addition, the weak gel was reduced in size by syneresis which produced over 50% of the liquid volume as brine. The reason for the gradual pH increase in the 200-325 mesh sand solution was not evident. Additional tests with dilute HCl acid indicated the 200-325 mesh sand did not contain significant quantities of carbonate minerals. X-ray images of sandpacks indicated the 200-325 mesh sand had a higher X-ray density than the 80-100 mesh sand even though the porosities of the two sands were nearly the same. The sand may have contained other minerals, such as clays, which could change the solution pH by ion exchange. For sandpack flow tests, where the proportion of sand to gel solution is larger, the solution pH would increase more rapidly and further inhibit the formation of a gel.

Other tests in sandpacks with the 80 to 120 mesh and 200 to 325 mesh sand were made for in situ gelation of the Cr(III)/biopolymer. The gelant solution was stock brine with 1,000 ppm xanthan and 100 ppm Cr(III) which was adjusted to a pH of 3.4. For each sandpack, 0.42 PV of the gelant was injected followed by 0.3 PV of 1000 ppm xanthan. After 24 hours to allow gelation, the brine permeability was measured. For the 80 to 120 mesh sandpack, the gel resistance factor was 800. For the 200 to 325 mesh sandpack, the resistance factor was less than 10 indicating virtually no gelation of the polymer.

The bottle and sandpack tests clearly indicate that screening tests must consider the effects of the reservoir matrix in the gelation process. The Cr(III)/biopolymer system required a weak acidic pH for polymer gelation. This Cr(III)/biopolymer was not a candidate gel system for carbonates reservoirs. The high capacity of these reservoirs to change the pH of injected solutions would probably inhibit the formation of these gel systems even for solutions containing pH buffers. In this study, the ability to control the time of gelation was of interest for gel placement using experimental model studies.

EXPERIMENTAL MODELS FOR GEL PLACEMENT

Successful gel treatments require placement of a gel in high permeability zones with minimal damage to the adjacent, less permeable, oil productive reservoir. Numerous laboratory studies have used single permeability floods or parallel floods with different permeabilities for testing the effectiveness of gels and fluid diversion agents. Although these studies were useful for measuring resistance factors of gels, these experiments can provide erroneous results on improvement of sweep efficiency. Single or parallel cores do not evaluate the effects of crossflow during placement of the diversion agents. Crossflow into the nearby oil productive zone during injection of profile modification agents can seriously impair flow and reduce sweep efficiency of the oil productive formation. Therefore, evaluation of profile modification agents must consider the impact of crossflow into the adjacent oil productive zone.

To measure the effect of crossflow, profile modification experiments using layered sandpacks with contrasting permeabilities were conducted. Two different vessels were used as sandpack holders. A high pressure model was constructed of aluminum for pressures up to 2,500 psi (17.2 mPa). The internal dimensions of this vessel were 7.69 cm in diameter and 54.6 cm in length. The wall thickness of the vessel was sufficiently thin to allow CT imaging of X-ray tracers. Experiments were conducted with a layered sand model using a potassium iodide as an X-ray tracer to monitor the flow path of fluids.

Also, a low pressure sandpack holder was constructed of a plexiglass cylinder with an internal diameter of 7.62 cm and a length of 51 cm. The model was used for displacement experiments with liquid pressures up to 100 psi (0.69 kPa. For some experiments, the model was used with a suitable liquid dye to visually observe liquid displacement. However, because these

observations were limited to the external surface of the sandpack, most experimental observations of fluid displacement were made using CT imaging. To provide contrast in X-ray density between the liquid phases, the displacement liquid was tagged with a high X-ray density salt which was usually 6 wt % of potassium iodide.

For heterogeneous sandpacks, layers of high and low permeability silica sands were packed parallel to the direction of flow. Different sized sands (20-40 mesh, 80 to 120 mesh, and 200 to 325 mesh) were used to obtain sand layers with different permeabilities. Each layered sandpack was prepared by placing a thin aluminum sheet in the cylindrical sand holder. The aluminum sheet was nearly the same diameter as the sand holder to minimize crossflow of different sized sands during the packing operation. An air vibrator attached to the sand holder was used to vibrate and settle the sand during the packing operation. The sands were wet packed with each sand poured into the tube partially filled with water. The aluminum divider was slowly removed after filling the tube with sand. The permeability contrast between layers of 80 to 120 mesh and 200 to 325 mesh sands was about 5, and the permeability contrast between 20 to 40 mesh and 200 to 325 mesh sands was about 50.

CT Cross Sections of Experimental Models

CT imaging was used for visualization of fluid flow and gel placement. Each CT scan was a 4 mm slice of the sandpack cross section. For a sandpack 51 cm in length, 25 CT scans at 2 cm intervals were obtained to characterize the sandpack. The resolution of the image along the sandpack axis was 3.2 % of the sandpack length. As shown in Fig. 10, by computer

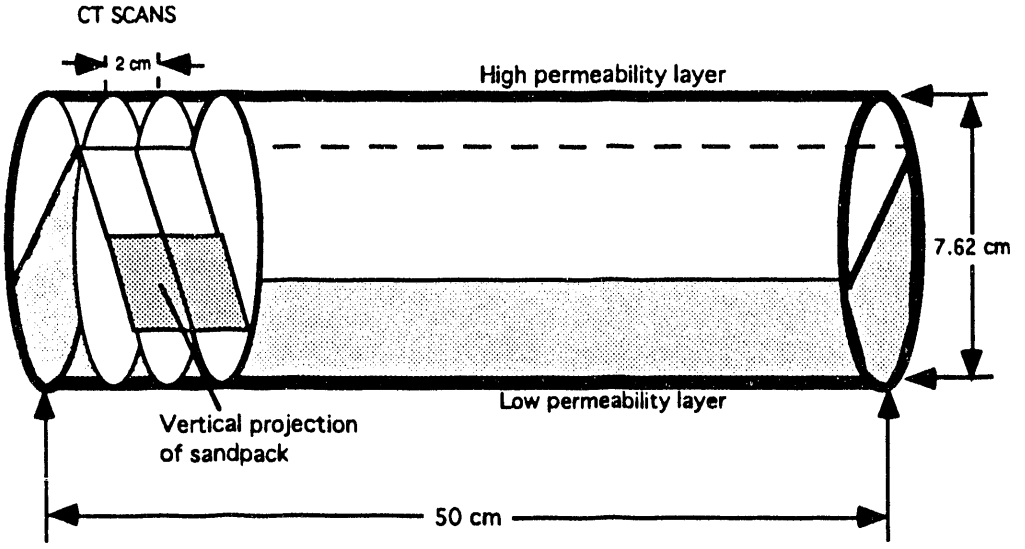

FIGURE 10. - CT scans of sandpack and with 2-dimensional image reconstruction of image along the sandpack axis.

reconstruction, a 3-dimensional image was obtained of the sandpack.[8] For this study, a 2-dimensional image was made showing a lengthwise projection of the sandpack perpendicular to the high- and low-permeability layer plane. The figures used in this report show the most permeable layer at the top of the image.

A potassium iodide tagging agent was used to provide an X-ray contrast between the injected and displaced fluids. Injected brines and polymer solutions contained 6 to 7.5 wt % of potassium iodide. To further enhance the X-ray images, the sandpack was scanned prior to injecting the tracer fluid. For each scan location, the appropriate background scan was subtracted from all subsequent scans. This enhanced the location and intensity of the injected tracer.

Flow Experiments for Polymer Placement

Initial experiments with layered sandpacks were performed by injecting a X-ray tagged brine into a brine saturated sandpack. The permeability contrast between layers of 80 to 120 mesh and 200 to 325 mesh sand was about 5. Density of the injected and the saturation brine had approximately the same density, thus minimizing gravity effects. These experiments were designed to demonstrate the simple case of permeability contrast between sand layers and the relative penetration of the injected brine. CT cross sections of the sandpack shown in Fig. 11 were made after injecting 0.15, 0.4, and 0.5 PV of brine. The distance of brine penetration for the high-permeability layer was about 5 times that of the low-permeability layer. Also, as shown in the CT cross sections, there was virtually no crossflow between the high- and low-permeability layers because the viscosity of the injected brine and the displaced brine were the same. For this idealized case of fluids with the same viscosity and mobility, the injection fluid placement was largely controlled by the permeability contrast of the porous media. The length of penetration into the high- and low-permeability layers (L_1/L_2) was proportional to the permeability contrast of k_1/k_2. For this experiment, the relative displacement of the two brine fronts remained nearly constant as the brine was injected. Other factors such as gravity and capillary forces also could influence this relationship in a reservoir. These factors were small because of large pores in the sandpack, fluid miscibility, and small differences in liquid densities.

Effect of Polymer Solution Viscosity and Permeability on Crossflow

There are many studies of gel properties in porous media. Typically, these studies measure the resistance to brine flow after gel formation. Although these studies are useful in gel assessment and the determination of residual resistance factors, flow through virtually any porous media can be effectively reduced if sufficiently high concentrations of polymer are used, and often, these polymer solutions have high viscosities. These studies ignore the problems associated with placement of high viscosity solutions which can seriously influence crossflow and damage to the lower permeability strata.

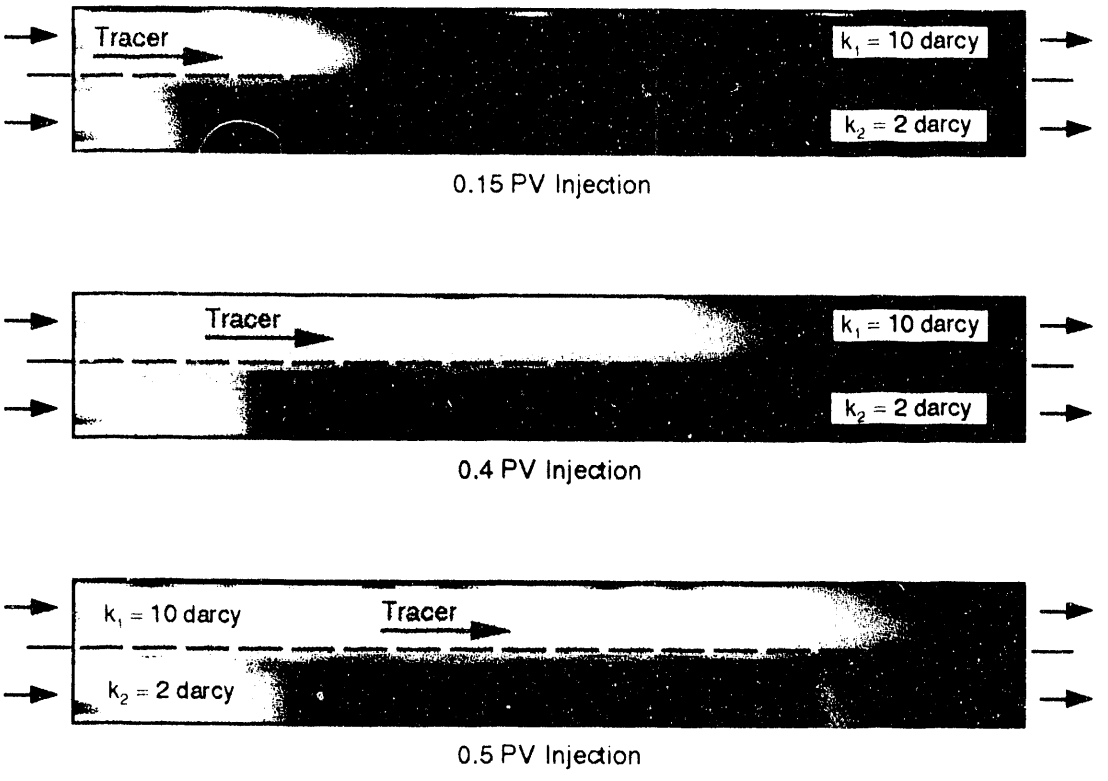

FIGURE 11. - CT cross sections of layered sandpack with a permeability contrast between layers of about 5. The figure represents a gray scale for the injected brine tracer profile where white is the location of high tracer concentration. The ratio of the brine penetration into the two layers was the same as the permeability contrast ($k_1/k_2 \approx 5$) between layers. Virtually no crossflow occurred because the viscosity or mobility of displaced and injected brines were nearly the same.

The objective of gel treatments is to restrict flow through fractures and high-permeability zones without significantly damaging the adjacent oil productive zones. This involves injection of a viscous polymer solution before gelation, hopefully in the high-permeability zone. For the injection of a polymer solution in a porous media, two dominant factors can influence the reduction in the mobility of the polymer solution, i.e., solution viscosity and permeability reduction resulting from polymer retention.

Layered sandpacks were used to show the effect of viscous crossflow on gel penetration and placement. For one experiment, the sandpack consisted of a high-permeability layer (k_1) of 80 to 120 mesh sand and a lower permeability layer (k_2) of 200 to 325 mesh sand. The permeability contrast (k_1/k_2) between the two sands was about 5. A polymer solution (1,500 ppm xanthan) was injected at a flow rate of 75 cm^3/hr. The polymer solution contained 6% potassium iodide as an X-ray tracer. Some polymer retention was expected as the polymer solution flowed through the sandpack. However, separation of the polymer and tagged brine was minimal because of the large

sandpack pores. Therefore, location of the polymer and tagging agent was nearly coincident and within the resolution limitations of the CT images.

A series of CT cross sections (Fig. 12) shows the relative position of frontal advancement after injecting 0.14, 0.28, 0.54, and 0.95 PV of polymer solution. The figures show only a small offset of the lower permeability polymer front and the large quantity of polymer crossflow into the low permeability layer. For this experiment, the ratio of the polymer viscosity to displaced brine (μ_p/μ_w) was much larger than the permeability contrast of the two layers ($k_1/k_2 = 5$) resulting in nearly total polymer invasion of the lower permeability layer.

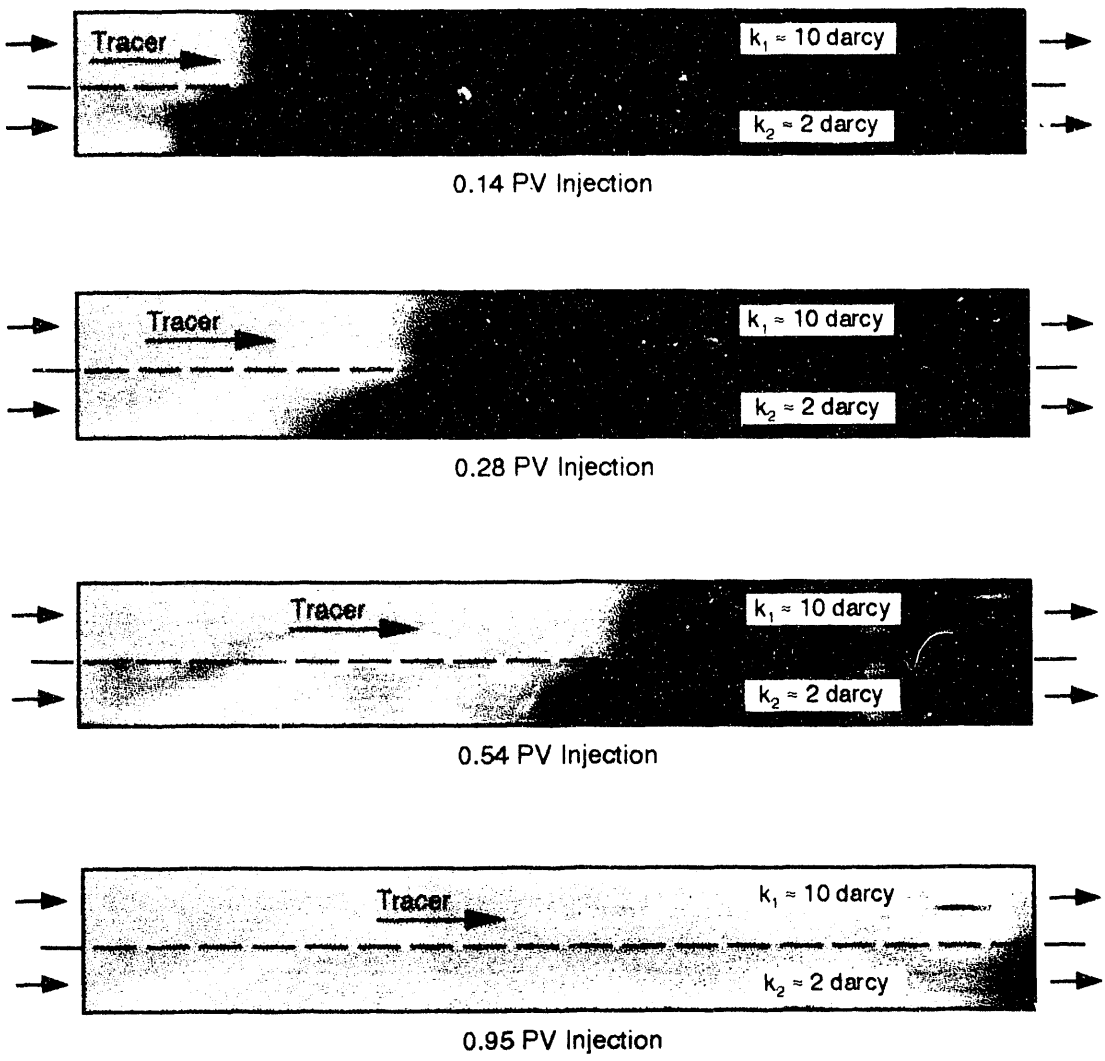

FIGURE 12. - CT cross sections showing the position of a 1,500 ppm biopolymer injection with a permeability contrast between layers $k_1/k_2 \approx 5$. The figures show only a small offset in the biopolymer fronts between the low and high permeability layers. The ratio of the displaced brine mobility to the injected polymer mobility $(\lambda_w/\lambda_p \approx 53)$.

A similar experiment was conducted with a brine saturated sandpack with a larger permeability contrast. The brine saturated sandpack consisted of 20 to 40 mesh and 200 to 325 mesh sand layers with a permeability contrast (k_1/k_2) of about 50. A 1,500 ppm xanthan polymer solution with 6% potassium iodide as an X-ray tagging agent was injected at a rate of 100 cm^3/hr. Figure 13 shows CT cross sections of the sandpack after injecting 0.19, 0.34, 0.59 and 0.73 PV of polymer. Even with the high-permeability contrast of the two layers, the cross sections show

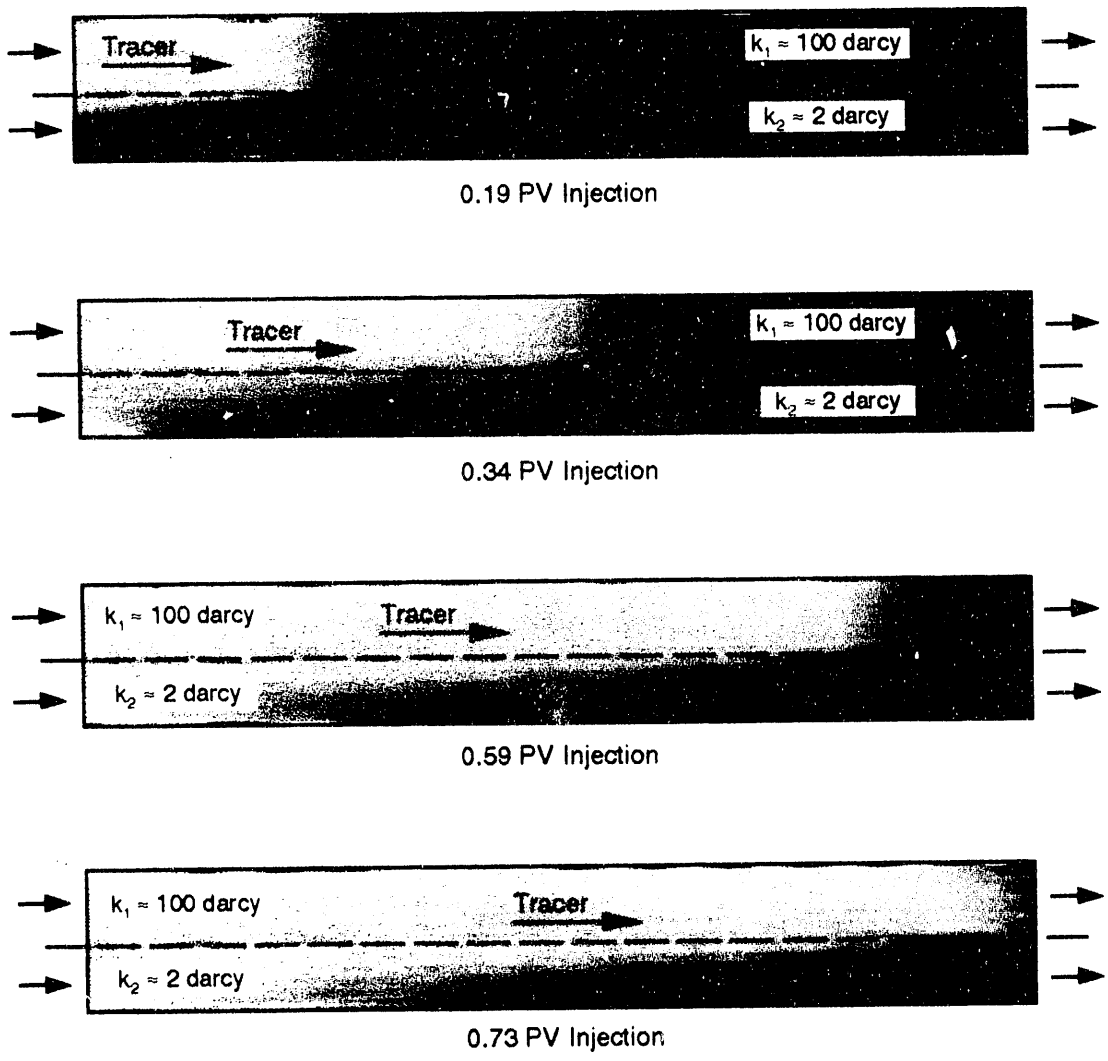

FIGURE 13. - CT cross sections showing the position of a 1,500 ppm biopolymer injection with a permeability contrast between layers $k_1/k_2 \approx 50$. For this experiment with a high-permeability contrast, the polymer resistance factor ($\lambda_w/\lambda_p \approx 53$) was too large for polymer placement without significant invasion ($\approx 50\%$) of the low-permeability layer.

considerable polymer invasion into the low-permeability layer. If the polymer solution was a gelant (polymer with crosslinker before gelation), the low-permeability layer would have been extensively damaged after formation of a gel. When the polymer penetrated to the end of the high-permeability layer (0.73 PV), over 50% of the low-permeability layer was invaded by polymer. This dramatically shows the problems associated with placement of viscous gelant in a high-permeability thief zone without extensively invading and damaging the adjacent oil-producing strata.

For a polymer flood where a gel is not formed, viscous crossflow may have a beneficial effect on oil mobilization. Polymer invasion may displace oil and ultimately increase sweep efficiency. However, polymer invasion of less permeable strata is not the objective of a gel treatment where a gel is formed to block subsequent flooding processes.

Of interest was the mobility ratio of the polymer to the displaced brine. CT cross sections were used to determine the distance of polymer penetration and the polymer frontal velocity of sand layer L_1. As the polymer penetrated the high-permeability layer, the distance and injection time gave a frontal velocity of 2.06 m/d (darcy velocity of 0.74 m/d). Since the polymer solution was a non-Newtonian fluid, mobility of the injected fluid was corrected for shear thinning and flow behavior in sandpacks. The power law Eq. 1 and the coefficients of Table 1 were used for rheological fluid properties. Also, flow behavior indices developed by Hejri[4] in sandpacks were used to determine the biopolymer mobility factor. The mobility factor (apparent viscosity) of the polymer in L_1 was estimated to be about 1,870 md/cP. Sorbie[9] defined a resistance factor (F_r) as ratio of the displaced fluid mobility divided by the polymer or gelant mobility. This gave a polymer resistance factor (F_r) of about 53 which was close to the permeability ratio ($k_1/k_2 = 50$) of the two layers. The value of $F_r k_2/k_1 \approx 1$ was too high for the polymer placement without significant invasion of L_2.

Sorbie[9] performed similar experiments with beadpacks with contrasting permeability layers. Newtonian liquids with different viscosities were used to simulate the injected polymer or gelant and displaced fluid. His study indicated an approximate guideline of $F_r k_2/k_1 \leq 0.3$ to reduce crossflow to an acceptable level.

Even this experiment, with relatively high-permeability contrast, was not sufficient to place the polymer solution without significant crossflow and invasion into the low-permeability layer. The polymer solution was too viscous for thief zone placement which emphasizes the need for gelant injection with a low viscosity and a low resistance factor.

Flow Experiments for Gel Placement

Experiments were performed for gel placement in layered sandpacks with a permeability contrast of 5. The sand layers were 80 to 120 mesh and 200 to 325 mesh silica sands. For this report, the term "gelant" is used to describe the polymer/crosslinker solution before gelation.

Gelant mixtures for these flow tests was xanthan polymer with 100 ppm Cr(III). The biopolymer concentration for gel experiments 1 and 3 was 1,000 ppm. For gel experiment 2, the biopolymer concentration was 1,500 ppm. Relatively low concentrations of biopolymer were used in these experiments because of the problems associated with polymer placement in the high-permeability layer. This was demonstrated in previous experiments which showed the effect of fluid viscosity on crossflow in layered sandpacks. Therefore, a gelant with a low viscosity was used. Bottle tests indicated xanthan concentrations of 1,000 ppm was the lowest practical limit to obtain reasonably firm gels.

Gelant solutions of the biopolymer and chromic chloride were prepared in brines with a concentration of 6.6% NaCl, 1.5% $CaCl_2$, and 0.5% $MgCl_2$, and the solutions were adjusted to a pH of 3.8. Previously, bottle and sandpack tests with this gelant and sand mixtures had indicated the different sands would influence the gelant pH and polymer gelation. These tests indicated the 80 to 120 mesh sand would increase the gelant pH to a value of less than 5 to form a gel; the 200 to 325 sand would increase the gelant pH sufficiently to inhibit gel formation.

For gel experiments 1, 2, and 3, a brine containing 7.5% potassium iodide was injected following gel placement. Then, CT scans were made to show the tracer flow path, and the areas of high flow resistance. These areas of high flow resistance indicating the gel location are shown in Figs. 14, 15, and 16 as CT cross sections.

For gel experiment 1, all injection flow rates were 100 cm/hr. The injected gelant was 170 cm^3 which was 0.4 PV of the high-permeability sand layer. This was followed by injecting 75 cm^3 of polymer (1,000 ppm without crosslinker) to displace the gelant from the sandpack inlet. The sandpack was shut-in for over 48 hours to allow for polymer gelation. Then, an X-ray tracer (200 cm^3 of 7.5% potassium iodide) was injected to indicate the path of lowest flow resistance.

The location of the gel was indicated by the area of high resistance to fluid flow in the high-permeability layer. A 3-dimensional reconstruction of the CT scans was used to describe the bulk volume of the gel mass. The sandpack porosity was about 36%. Therefore, gel volume was measured as 36% of the bulk volume.

Figure 14 shows the X-ray cross section after injecting the brine tracer. The figure shows the gel location in the high-permeability layer; an area of higher resistance to the injected brine tracer. The volume of gel measured by CT imaging (62 cm^3) corresponds to approximately 0.15 PV of the high-permeability layer or the gel occupied about 37% of the injected gelant. The gel location was later verified by removing the sandpack from the holder. Physical examination indicated this section of the sandpack was cemented by the gel and the bulk was approximately the same as measured by CT imaging. A gel was not formed for approximately 63% of the gelant volume. Some loss in gelant volume may have resulted from polymer filtration or incomplete

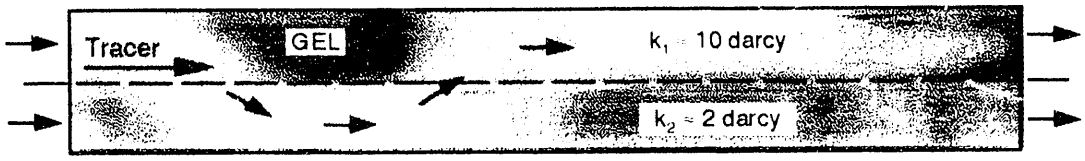

FIGURE 14. - CT cross section of gel placement. Gel location is indicated by the flow path of an injected brine tracer. Because much of the gelant crossflowed into the low-permeability layer, the gel volume was measured as only 37% of the injected gelant. In the low-permeability layer, a gel was not formed because the gelant pH increased sufficiently to inhibit gel formation.

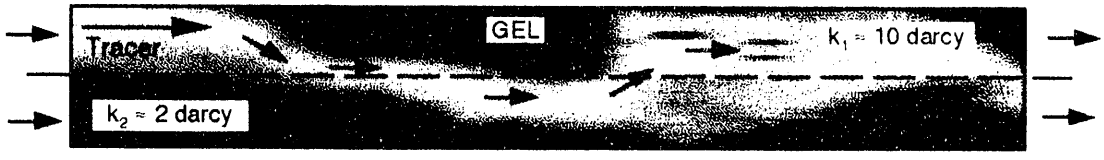

FIGURE 15. - CT cross section of gel placement. Gel location is indicated by the flow path of an injected brine tracer. For this experiment, a gelant and a polymer solution with the same viscosity before gelation were injected at the same rate into the high- and low-permeability layers. Because of lower permeability in the lower layer, the biopolymer crossflowed into the high-permeability layer diverting the gelant into the upper part of the high-permeability layer. The gel placement in the high-permeability layer was measured as 54% of the injected gelant.

FIGURE 16. - CT cross section of gel placement. Gel location is indicated by the flow path of an injected brine tracer. For this experiment, the gelant and a brine were simultaneously injected into the high- and low-permeability layers. The rate of brine injection was 2.3 to 2.75 times the rate of gelant injection. By simultaneous injection of a brine at a higher injection rate into the low-permeability layer, gelant crossflow was reduced and about 66% of the injected gelant was placed in the high-permeability layer.

gelation. However, most of the remaining gelant probably crossflowed into the lower permeability layer where the gelant pH increased sufficiently to inhibit gel formation. Most of the gelant loss was attributed to gelant flow into the lower permeability layer. If the pH changes resulting from the lower permeability sand were not present, the gelant would have resulted in significant damage to the lower permeability layer.

A second gel experiment was performed to increase gelant placement in the high-permeability layer. For this experiment, the gelant (100 ppm Cr(III) and 1,500 ppm biopolymer) was injected

at 100 cm^3/hr into the high-permeability layer. Simultaneously, a polymer solution of the same concentration was injected at 100 cm^3/hr into the low-permeability layer. The pH of the injected gelant was 3.8; the polymer solution was 4.0. Before gelation both fluids had the same viscosity. The objective was to use a second injection to prevent gelant crossflow. A total of 200 cm^3 (0.48 PV of the high-permeability layer) of gelant and 200 cm^3 (0.48 PV of the low-permeability layer) of polymer were injected. The gelant injection step was followed by injecting 125 cm^3 of polymer without crosslinker to displace the gelant away from the injection inlet. As in gel experiment 1, the sandpack was shut-in for over 48 hours to allow for polymer gelation. Then, an X-ray tracer (250 cm^3 of 7.5% potassium iodide) was injected to indicate the brine flow path and the areas of flow resistance.

Figure 15 shows the X-ray cross section after injecting the brine tracer and the gel location in the high-permeability layer. As shown in Fig. 15, the shape of the gel mass was influenced by the injection of biopolymer into the low-permeability layer. The gel volume was measured as 54% of the injected gelant volume. Because of the lower permeability in the lower layer, some of the biopolymer flowed into the high-permeability layer diverting the gelant into the upper part of the high-permeability layer. As injection of the gelant progressed, the frontal area of the gel mass filled the high-permeability layer. This indicated premature gelation during injection. The frontal area of the gelant slug with higher viscosity resulted in displacement of the biopolymer and some loss of the gelant into the low-permeability layer.

Two problems were noted with this experiment for gel placement in the high-permeability layer. First, the biopolymer solution was too viscous to balance the pressure between layers for the two fluids injected at the same flow rate. A lower viscosity biopolymer equivalent to $\mu_g k_2/k_1$ (where μ_g = gelant viscosity) would have resulted in better placement of the gelant. Also, as gelant injection progressed, premature gelation resulted in crossflow and loss of the gelant in the lower permeability layer. Premature gelation is another problem associated with gel placement in high-permeability layers.

A third gel experiment was performed to increase gelant placement in the high-permeability layer. For this experiment, a gelant (100 ppm Cr(III) and 1,000 ppm biopolymer) was injected at 100 cm^3/hr into the high-permeability layer. Gelant volume was 150 cm^3 (0.32 PV) of the high-permeability layer. Simultaneously, brine was injected into the low-permeability layer at a higher flow rates ranging from 230 to 275 cm^3/hr. The gelant injection step was followed by injecting 100 cm^3 of polymer without crosslinker to displace the gelant away from the injection inlet. As in gel experiment 1 and 2, the sandpack was shut-in for over 48 hours to allow for polymer gelation. Then, an X-ray tracer (325 cm^3 of 7.5% potassium iodide) was injected to indicate the brine flow path and the areas of flow resistance and location of the gel.

For the third gel experiment (Fig. 16), a larger proportion of the gelant was placed as a gel in the high-permeability layer. The gel volume was measured as 66% of the injected gelant. Crossflow was reduced by injecting a second fluid in the lower permeability layer. Even with brine injection into the second layer, the injection rate appeared too low to completely balance the gelant injection, and some crossflow occurred. In the porous media, there are considerable uncertainties in the estimate of the polymer viscosity and mobility. The porous media has a strong effect on the shear rate and apparent polymer viscosity. However, the experiment demonstrated that simultaneous injection of the gelant and a second fluid may be a useful method for reducing crossflow of the gelant.

RESULTS AND DISCUSSION

The rationale for using simultaneous injection of a gelant and another fluid to reduce crossflow was as follows. For injection rates (q_1 and q_2) into the high- and low-permeability layers (L_1 and L_2), the relationship for Darcy flow of Newtonian fluids was:

$$\frac{q_2}{q_1} = \frac{k_2 A_2 \Delta P_2}{\mu_2 L_2} \frac{\mu_g L_1}{k_1 A_1 \Delta P_1} \tag{2}$$

For Newtonian fluids, μ_2 was the fluid viscosity injected in L_2; μ_g the gelant viscosity. To simplify Eq. 2, the cross sectional areas were assumed to be equal ($A_1 = A_2$). At some distance where $L_1 = L_2$, and for the condition of balanced pressure ($\Delta P_1 = \Delta P_2$) between the two injected fluids, Eq. 2 reduced to:

$$q_2/q_1 = k_2\mu_g/k_1\mu_2 \tag{3}$$

For equal injection rates ($q_2 = q_1$), the equation suggested a pressure balance between the fluids could be obtained by injecting an appropriate fluid viscosity into the lower permeability layer where $\mu_2 = k_2\mu_g/k_1$. For example, a permeability contrast (k_1/k_2) between layers of 5 would require injection of a fluid with a viscosity of $\mu_g/5$ into the lower permeability layer. This was one of the problems found in gel experiment 2 where the viscosities of the gelant and polymer solution were the same.

Also, when q_2 was greater than q_1, a less viscous fluid would be required to balance the pressure of the injected fluids. This was the strategy used for gel experiment 3, although some gel crossflow occurred because of nonideality of polymer flow.

Equation 3 will apply only to Newtonian fluids. The previous discussion has not considered the shear thinning properties of polymer solution and that the rheological properties are dependent upon flow characteristics of the porous media. In addition, polymer retention can occur as a gelant or polymer solution flows through porous media which can result in a reduction of the gelant or

polymer mobility. Therefore, to obtain balanced flows between layers, the rheological properties and mobility of each injected fluid must be considered. Further discussion of biopolymer mobility in porous media may be found in other technical papers.[4,10]

In field applications, however, the technique of simultaneous injection would require zone isolation of the high- and low-permeability zones, and the simultaneous injection of the gelant into the thief zone and injection of another lower viscosity fluid into the oil productive strata.

There are other factors which may effect the placement of the gelant. These include the effects of vertical to horizontal permeability and oil saturation. These factors were not considered in the experimental models.

The ratio of vertical to horizontal permeability typically is less than unity because of reservoir stratification. Zapata and Lake[11] discussed the effect of these relationships on vertical equilibrium. Assuming there is not a barrier to flow between layers, vertical equilibrium will depend upon the reservoir aspect ratio (L/H), and the ratio of vertical to horizontal permeabilities (k_v/k_h). They proposed the following relationship as a measure of vertical equilibrium:

$$R = L/H(k_v/k_h)^{0.5} \tag{4}$$

Using experimental and simulation data, they determined a range for values of R. Vertical equilibrium was essentially achieved when $R \geq 10$, and for the condition of virtually no crossflow when $R \leq 0.1$. For example, a reservoir with an aspect ratio of 50 (L = 1, 000 ft and H = 20 ft), these values of R would correspond to a vertical permeability less than 4×10^{-6} times k_h to achieve no crossflow, and greater than 0.04 times k_h to achieve total crossflow and vertical equilibrium. In between these extremes, the degree of crossflow would vary depending on the value of R.

Finally, oil saturation and relative permeability may influence the relative penetration and crossflow of the polymer injection. Assuming the high-permeability layer is a watered-out zone, the following numerical simulations were performed for a layered model with a permeability contrast of 50. The viscosity of the oil and water were 3.0 and 0.8 cP, respectively. The injected polymer was 3,000 ppm of polyacrylamide. The figures represent a gray scale for the concentration profile of the injected polymer where white is high polymer concentration.

The results of the simulation are shown in Fig. 17A where the S_o of the high- and low-permeability layers were 25% and 75% respectively, representing a watered-out, high-permeability layer. For Fig. 17B, the S_o of the high and low permeability layers were both 75%. Comparison of figures Figs. 17A and B shows the concentration profiles after injecting 0.6 PV of polymer. The watered-out layer had less polymer penetration and greater crossflow than the layer with higher oil saturation.

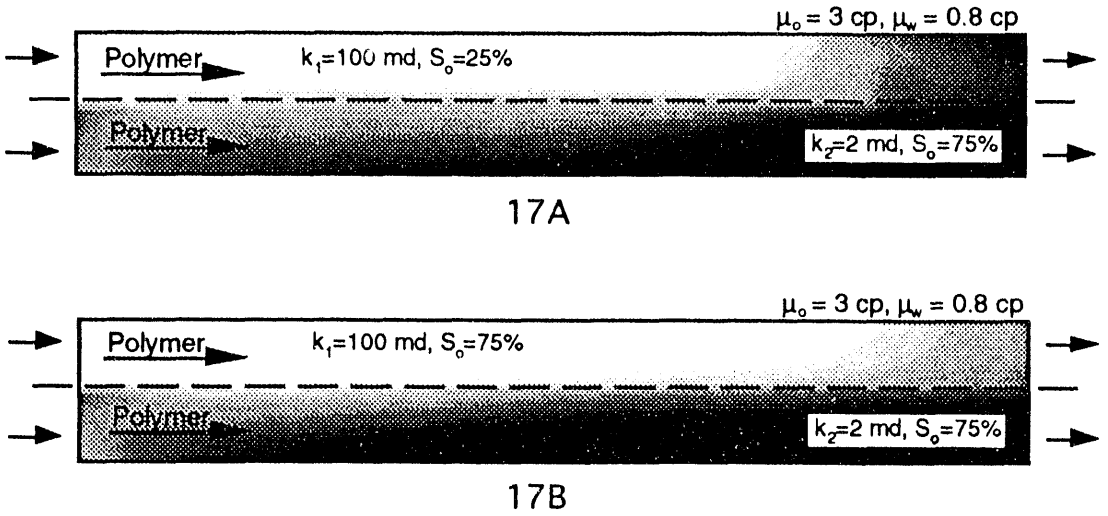

FIGURE 17. - Numerical simulation demonstrating the effect of oil saturation on crossflow in a two layer system. Viscosity of the saturation fluids of oil and water were 3.0 and 0.8 cP, respectively. The polymer resistance factor of the watered-out layer (Fig. 17A) was higher, resulting in more crossflow than the layer with higher oil saturation (Fig. 17B).

The difference between the two simulations was due to the fluid mobility of the two high-permeability layers. For Fig. 17A, the displaced fluid was mostly brine, and for Fig. 17B, the fluid displaced was mostly oil with a higher viscosity. Consequently, fluid mobility of the watered-out layer was larger, and therefore, the polymer resistance factor ($Fr \approx \lambda_w/\lambda_p$) was larger than the layer with higher oil saturation ($Fr \approx \lambda_o/\lambda_p$). The simulation study indicated that for a reservoir with an oil viscosity greater than the reservoir brine, a highly watered-out zone would result in more viscous crossflow with a corresponding lower quantity of polymer placement in the high-permeability layer.

CONCLUSIONS

1. Viscous crossflow into oil-productive formations during gel placement is minimized by gelant formulations with a low viscosity or low resistance factor.

2. A gelant with a low resistance factor during injection provides better placement of gel treatments in unfractured reservoirs.

3. An effective gelant with a low resistance factor during placement is required for polymer gels to effectively improve the sweep efficiency of CO_2 floods.

NOMENCLATURE

A = Cross sectional area, cm^2

F_r = mobility ratio of the displaced fluid mobility divided by the mobility of the injected fluid.

k_w = permeability to brine, md [μm^2]

k_{wp} = permeability to brine after polymer, md [μm^2]

K = consistency index, cP^n [$(mPa \cdot s)^n$]

n = flow behavior index, dimensionless

ΔP = pressure drop, atm [MPa]

u = darcy velocity, ft/d [m/s]

q = injection rate, cm^3/s

γ = shear rate, s^{-1}

μ = viscosity, cP [$mPa \cdot s$]

λ = mobility factor mD/cP [$mPa \cdot s$]

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