PRACTICAL DESIGN OF MOBILITY CONTROL POLYMER PROJECTS

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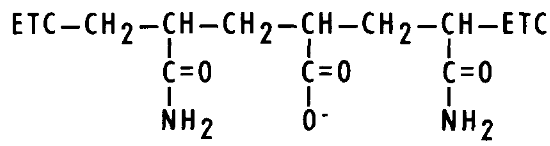
ABSTRACT

Modern mobility control polymers provide the petroleum engineer with a powerful tool for increasing oil production. Successful applications, however, are likely to result only from sound project engineering and careful attention to operating methods. This paper emphasizes a practical understanding of the properties of mobility control polymer solutions as they are likely to affect the success or failure of a project in a given field. Many unsuitable applications can be identified through reference to some simple guidelines. Further selectivity results from an appreciation of the flow patterns of polymer solutions in specific reservoir situations. Good reservoir engineering maximizes the chances for incremental production; methods appropriate to the use of polymers in both waterfloods and surfactant polymer floods are surveyed. Even the best engineering efforts can be negated by careless or uninformed operations in the field. Particular attention is given to potential operational problems and the means available for dealing with them or avoiding them altogether.

THE POLYMERS

After nearly twenty years, economics and the harsh requirements of the petroleum reservoir environment have narrowed the number of currently acceptable mobility control polymers to about two or three. These survivors are very useful, but not perfect, and part of the secret of a successful project lies in understanding the shortcomings of the polymers.

Polyacrylamide (Figure No. 1) has a hydrocarbon backbone like hexane. This kind of backbone confers both immunity from bacterial attack and flexibility, which tends to make the molecule somewhat fragile. The molecule "AMPS®" (2-acrylamido - 2 methylpropanesulfonic acid) is sometimes incorporated into these polymers to impart improved injection properties in tight rock[1] and decreased retention[2] in some instances. Xanthan gum (Figure No. 2) or "biopolymer" has a backbone of sugar and requires a preservative. Its relatively stiff backbone results in considerable resistance to mechanical breakage, but somewhat increased susceptibility to chemical breakage. In brine solutions[3, 4] both molecules are in the 0.3 to 0.4 micrometer range in overall size. This size is significant with respect to pore sizes in rock. Some appreciation of the need for selecting the right size molecule for a particular application can be gained by inspection of the data from an experiment in

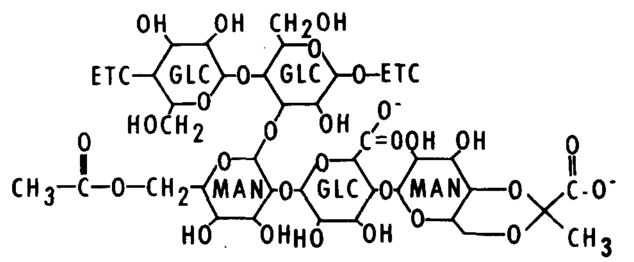


POLYACRYLAMIDE

$C_{253,000}\ H_{423,000}\ N_{56,667}\ O_{113,333}$

M.W. 5,500,000

FIGURE 1—CHEMICAL FORMULA FOR A TYPICAL ACRYLAMIDE-BASED MOBILITY CONTROL POLYMER



XANTHAN GUM

$C_{187,000}\ H_{270,000}\ O_{155,000}$

M.W. 5,000,000

FIGURE 2—CHEMICAL FORMULA FOR XANTHAN GUM

which suspensions of spherical particles of uniform size were passed through pieces of Berea sandstone (Table 1).[5]

TABLE 1 INJECTION OF STANDARD LATICES INTO BEREA SANDSTONE

A. Berea sandstone; air permeability 500 md; brine permeability *about* 250 md

2.95 micron latex	- plugged on face and to shallow depth in core
0.557 micron	- initially penetrated core, then plugged and filtered out
0.088 micron	- no plugging
Latex No. 636 (0.18 micron average)	- no plugging

B. Berea sandstone; air permeability 300 md; brine permeability 1500 md

None of the above latices plugged the specimen

MOBILITY CONTROL—A SIMPLE CONCEPT

Most people with waterflooding experience recognize that it's a lot easier to get good recovery of 35° API oil than of 20° oil because of the approximately 15-fold difference in viscosity. The high viscosity of the 20° gravity oil promotes inefficient bypassing of water and lower recoveries at economic limit. The best way to improve this situation would be to change the viscosity of the 20° gravity oil to that of the 35° oil. A slightly less desirable, but usually more practical, solution is to slow down the water by a factor of about 15. This will give about the same recovery efficiency as a waterflood of the 35° gravity oil (although there will obviously be some difference in overall rate). This is basically what mobility control polymers are designed to do: decrease the mobility of the water relative to the oil with the objective of improving the efficiency of a displacement process.

POLYMER MECHANISMS

There are two ways of decreasing the "mobility" of water flowing through a pipe: increase the viscosity of the water or decrease the pipe diameter by allowing it to scale up. In the same way, there are two ways of decreasing the mobility of water in the capillary size passages in a reservoir rock: increase the viscosity of the water or decrease the size of the passages and cut the effective permeability of the rock to water. Mobility control polymers operate both ways. The Xanthan gums tend to function principally by increasing the viscosity of water. The acrylamide-based polymers both increase the viscosity of water, especially at low salinity levels, and "interact" with the reservoir rock, leaving after their passage a very small quantity of "lodged" polymer, which causes a decrease in the permeability of the rock.

The quantity of polymer required for permeability reduction has been the subject of some recent studies.[2,6] The data plotted in Figure No. 3 (for conditions shown in Table 2) show that the quantity of polymer taken up in a rock can be made as low as 1 to 2 lb per acre-ft by pre-treatment with an adsorption preventing chemical.[5,7] The mobility decrease observed when polymer was passed through this treated core was the same as that produced in untreated rock (normal loss 100 lb per acre-ft).

TABLE 2 CONDITIONS OF TEST OF MOBILITY CONTROL POLYMER RETENTION IN A NON-ADSORBING CORE

Core:	1 in. x 10 in. Berea sandstone; normal polymer loss 100 lb/A-ft; treated to prevent chemical adsorption
Tracer:	Potassium Thiocyanate
Polymer Solution:	250 ppm hydrolyzed polyacrylamide in 3% NaCl
Estimated Loss:	Less than 5 lb/acre-ft; measured values 1 to 2 lb/acre-ft
Mobility Control:	Unaffected by treatment to prevent adsorption

MODEL STUDIES

The way an injected fluid will move in a specific reservoir situation may be hard to visualize, particularly if fluids of differing mobilities are involved. Some model studies simulating the flow of injected water or polymer in different pilot test configurations illustrate some general principles.

Figure No. 4, taken from a time-lapse motion picture, shows the "polymer" banks expanding radially from the injection wells. The oil outside the pattern, which is being pushed very efficiently by the polymer, heads for the nearest point of low pressure, in this case the pilot producing well. The encroachment of this outside oil, as shown in Figure No. 4, ultimately resulted in the production of 142% of the oil lying within the pattern boundaries. Figure

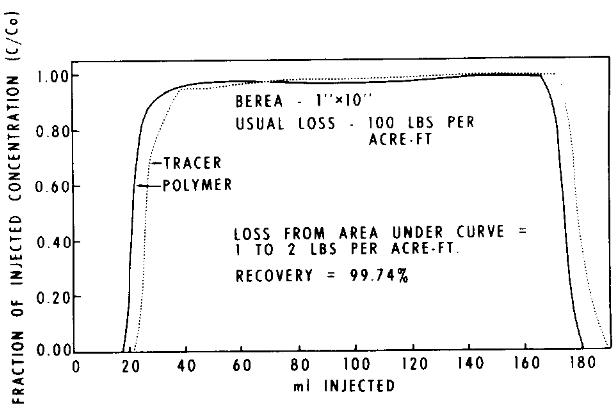


FIGURE 3—LOSS OF MOBILITY CONTROL POLYACRYLAMIDE IN NON-ADSORBING SAMPLE OF BEREA SANDSTONE

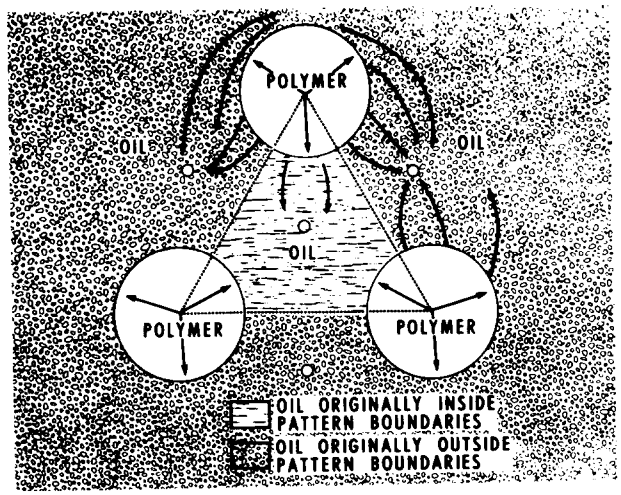


FIGURE 5—MODEL STUDY OF A POLYMER FLOOD IN A FOUR-SPOT PILOT WITH PATTERN EXTENSION GUARD WELLS

No. 5 shows the use of "pattern extension" wells to prevent the encroachment of oil from outside the pattern. This strategy was actually used in some polymer pilot tests.[8]

These example studies demonstrate the following:

1. Low-mobility banks tend to expand radially in a uniform way.
2. An unfavorable mobility situation results in unstable displacement fronts.
3. A lot can be learned by trying to determine the path of least resistance for injected fluid.
4. Pilot floods require care in designing and interpreting.
5. A displacement process will result in oil production only if it is conducted in such a way that pressure is developed near producers.

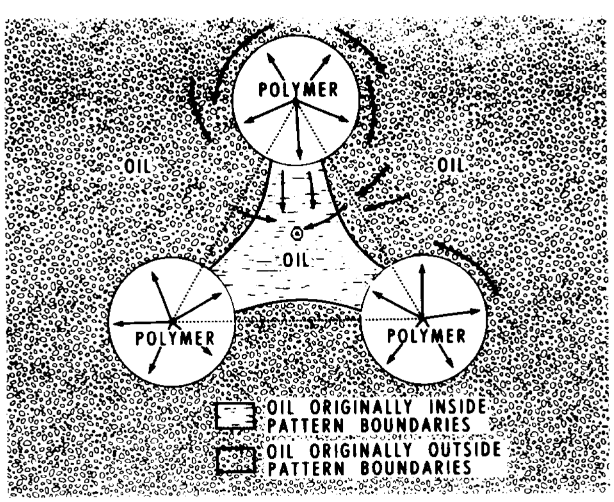


FIGURE 4—MODEL STUDY OF A POLYMER FLOOD IN AN UNGUARDED FOUR-SPOT PILOT

6. Model studies (now preferably run on a computer) may be required to resolve the behavior of complex systems.

Some of this sounds quite obvious, but some plans proposed in the past for polymer or surfactant floods seem to have ignored these points. Examples of situations preferably avoided follow:

1. Injection of expensive low-mobility fluid into marginal producers near an oil-water or gas-oil contact will result in the use of high-cost fluid to displace a lot of water or gas, not oil.
2. Injection of low-mobility fluids into reservoirs containing communicating gas caps or bottom water zones can be expected to result in these zones being substantially invaded by the low-mobility fluid.
3. A single injection well pilot test will usually be unsatisfactory.

SOME GUIDELINES FOR REDUCED MOBILITY FLOODS

The following principles, based largely on past mistakes, should help to avoid misapplications of polymer or surfactant-polymer processes, both of which involve fairly high-cost, low-mobility fluids:

1. Polymer flooding is for improving waterfloods, not fixing them. If a waterflood is not behaving up to expectation, ask why. Something other than mobility control is probably required.
2. If fluid injection exceeds fluid production to

an extent significantly greater than that required for fill-up, injecting a high-cost, low-mobility fluid is likely to be expensive and unlikely to solve the imbalance problem.

3. For straight polymer flooding, a polymer will probably reduce the mobility of water by a factor of 10 economically, or under favorable conditions by a factor of 20.
4. For a surfactant-polymer flood, the polymer will reduce the mobility of water by a factor of 20 to 30 without damaging the economics irreparably.
5. High oil viscosities favor polymer flooding; low viscosities favor a surfactant-polymer process.
6. If simple, idealized calculations don't look favorable for a low-mobility process, complicated ones will not look better.

ESTIMATING POLYMER FLOOD FEASIBILITY

The last item on the above list suggests a method for getting some idea of whether or not a polymer flood makes sense: Use simple, established methods to calculate a waterflood performance, then calculate polymer flood performance assuming it will be the same as that of a waterflood of a lower viscosity oil. The comparison should be made only at a point near the economic limit—95% water cut is traditional. The results will not be exact; the idea is to get some comparative numbers.

At a water cut of 95% areal sweep is not a large factor, so only displacement efficiency and vertical conformance need to be considered. The Buckley-Leverett calculation uses relative permeability data and fluid viscosities to obtain displacement efficiency estimates.[9] Figure No. 6 shows standard "f" vs. "S_w" plots derived from relative permeability data from a Squirrel sand reservoir in Kansas.[11] Lines tangent to the curves at the f value of 0.95 (95% water cut) intersect the f = 1 line at points related to the percentage recovery of waterflood mobile oil as indicated by the supplementary scale. The results are shown in Table 3 for several viscosities of oil. If we assume that we can decrease the mobility of water economically by a factor of 10, we can determine the resulting change in displacement efficiency by comparing the recoveries at oil viscosities differing by a factor of 10. The data in Table 3 show that the displacement efficiency of a flood of 120 cps oil

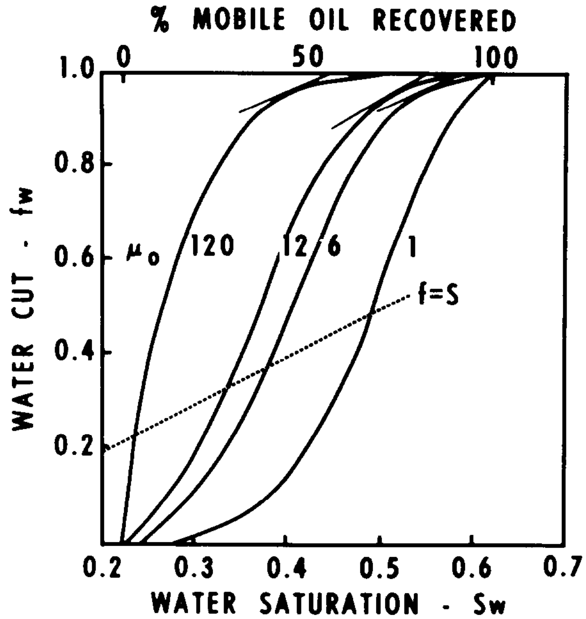


FIGURE 6 BUCKLEY-LEVERETT PLOT SQUIRREL SAND EXAMPLE

could be improved markedly. A waterflood of 6 cps oil already has a displacement performance which is 93%, and polymer could not improve this too much.

The effect of polymer on vertical conformance, which is due to reservoir heterogeneity, can be evaluated by a simple Stiles calculation if only relative values are required.[10] Stiles calculations of recoveries using core log data from the same Squirrel sand reservoir are shown in Table 3 for a water cut of 95%. These results show that a large improvement in vertical conformance might be obtained by the use of a mobility control polymer in the 120 cps oil case. A modest improvement would be expected from the use of polymer if the oil in the reservoir were 6 cps viscosity. Since the Stiles

TABLE 3 ESTIMATES OF OIL RECOVERY AT 95% WATERCUT BY SIMPLE CALCULATION TECHNIQUES

Oil Viscosity Centipoise	Recovery As Per Cent of Waterflood Mobile Oil: Displacement Efficiency (Buckley-Leverett)	Vertical Conformance (Stiles-Core Log)	Product
1	1.000	0.950	0.950
6	0.925	0.806	0.745
12	0.850	0.785	0.667
120	0.550	0.514	0.283

calculation ignores the effects of displacement efficiency, it also over-predicts recovery unless corrected. It is not unusual to see the displacement efficiency factor and the vertical conformance factor multiplied together to give an over-all efficiency factor (also shown in Table 3). This is probably a little too pessimistic.

The situation in the field from which the data were taken approximated that for the 120 cps oil examples. Combined primary and waterflood production amounted to about 40% of the 515 bbl of mobile oil in place, and polymer flooding, with a mobility reduction of about 8, resulted in recovery of about 80% of the mobile oil. The calculations are therefore not exact, but the indications with respect to the desirability of polymer flooding correspond to the results in the field test. Had the field contained 12 cps oil, polymer flooding calculations would still have looked favorable. For a 6 cps oil, the results would have been mildly encouraging. Polymer flooding calculations for 1 cps oil in this reservoir would have appeared unfavorable.

CLASSIFICATION OF POLYMER FLOODS

Polymer floods might be divided into three categories depending on the philosophy behind them:

1. The "traditional" polymer flood—the use of a partial pore volume of a dilute polymer solution optimizes some economic indicators. Incremental recoveries range from 30 to 80 bbl per acre-ft.
2. The "insurance" flood—a low concentration of polymer is used to ensure good waterflood performance despite the absence of any indications of economic benefit from engineering calculations.
3. The "all-out" polymer flood—maximum technology is combined with extended use of polymer in an effort to maximize the recovery of high-value oil.

A surprising number of polymer floods have been insurance floods, sometimes with unanticipated good responses (References 12 and 13, for example). Insurance floods may have the added feature of preparing a reservoir for a subsequent tertiary effort with surfactants.[14] The third type of flood can be used in some higher viscosity reservoirs to obtain recovery increases of the same magnitude as those usually projected only for surfactant processes, which are generally restricted to lower viscosity crudes. Adsorption preventing agents[7] may be required to obtain the desired performance. Cost levels may be quite high for this kind of flood. Only a couple of small polymer floods approximating the all-out situation have been run,[8,11] but incremental oil production on the order of 200 bbl per acre-ft indicates that the all-out flood should find wider application at today's oil prices, particularly if government assistance can be obtained.

SURFACTANT-POLYMER FLOOD FEASIBILITY ESTIMATES

The surfactant-polymer process is aimed at the irreducible oil saturation left behind by waterflooding. The chemical requirements for a given situation can be determined only by laboratory tests, so average values have to be used. The following procedure gives results which are probably optimistic in most cases, so unfavorable economics based on this method are a definite red flag. The procedure for a waterflooded field is as follows:

1. Using the equation $\lambda_t = \frac{k_w}{\mu_w} + \frac{k_o}{\mu_o}$ and relative permeability data, calculate the mobility of mixed oil and water banks. Determine the minimum mobility (see Figure No. 7 for examples). Determine mobility control requirements by comparing this figure to the mobility of water (k_w/μ_w) in oil-free rock.
2. Determine the composition, f, of the stabilized oil-water bank displaced by the surfactant slug by finding the value at which $f = S_w$ from a plot like Figure No. 6.
3. Assume the surfactant flood will contact the same fraction of the reservoir as that represented by primary plus waterflood production. This can be obtained by dividing total production by total waterflood mobile oil.
4. Assume the oil saturation in the contacted part of the reservoir is equal to the irreducible waterflood saturation as determined from laboratory tests and/or core log and field test data.
5. Calculate chemical costs on the basis of the contacted reservoir volume as 8% of pore

volume of surfactant at \$5/bbl and 60% of pore volume of polymer at \$0.33/bbl.

6. Calculate oil recovery as 70% of the irreducible oil saturation in the contactable portion of the reservoir. Calculate chemical costs per barrel of oil.
7. From the contacted volume 3, the volume of displaced oil 6, and the composition of the oil-water bank 2, calculate the amount of injection to first production response, and the time required.

As an example, consider that a field has the relative permeability behavior of Figure Nos. 6 and 7, contains 6 cps oil, is 30 ft thick, has a porosity of 20%, is developed on a 40-acre, 5-spot pattern, has an injection rate of 300 bbl/day/well, and has produced 400 bbl/acre-ft to the end of waterflooding. Note from Figure No. 6 that the irreducible oil saturation is 38% (S_{wro} = 62%). Relative permeability to 1 cps water in clean rock is equal to 1.

Table 4 summarizes some of the pertinent data. The following results were obtained:

1. The mobility of water must be reduced by a factor of at least 15 to give stable displacement.
2. The bank contains 40% water and 60% oil.

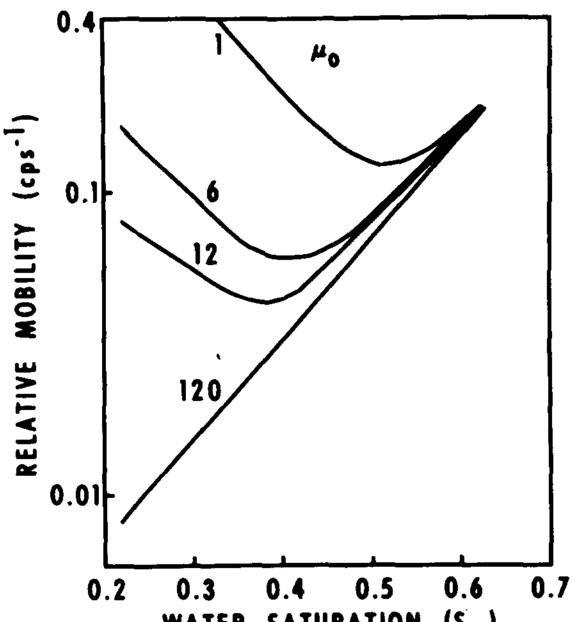


FIGURE 7—OIL WATER BANK MOBILITIES FOR SURFACTANT FLOODS IN SQUIRREL SAND

3. The contacted part of the reservoir is 64.4%.
4, 5, 6. Chemical costs are \$2.25 per barrel of oil.
7. Injection to production response is 166,872 bbl per pattern, requiring 18 months.

These chemical costs are in the lower range of those calculated for surfactant-polymer floods. Note that over 90% of the chemical costs are incurred before any response is obtained. Equipment costs for handling and mixing chemicals will usually be modest compared to the cost of the chemicals, but some development and workover costs may have to be added to ensure effective use of the process.

TABLE 4—ESTIMATES OF MOBILITIES OF STABILIZED OIL-WATER BANKS FORMED DURING SURFACTANT-POLYMER DISPLACEMENT PROCESSES

	Oil Viscosity - cps			
Calculation Results	1	6	12	120
S_w at Minimum Bank Mobility (Fig. 7)	0.53	0.40	0.37	0.22
S_w when f equals S_w (Fig. 6)	0.49	0.38	0.33	0.23
Minimum Mobility Value (Fig. 7)	0.13	0.064	0.046	0.0083
Mobility for $f=S_w$	0.13	0.068	0.051	0.0083
Average Bank Mobility	0.13	0.066	0.0485	0.0083
Decrease required of Polymer to achieve 1:1 ratio	7.7	15	21	120

NEXT STEPS

If the field looks satisfactory and the preliminary calculations look favorable, the next step is usually to acquire more information, particularly in the case of a high-cost surfactant flood. Assistance in getting this needed information can be obtained from good consultants, independent laboratories, and people with something to sell. Information concerning the condition of the field can be obtained by injecting tracers, studying waterflood behavior, determining *in situ* oil saturations, and running transient well tests and special logs.

Laboratory studies using materials from the field should include determination of the mobility control effectiveness of different polymers at different concentrations in the proposed injection fluids. Table 5 is an abbreviated example of some of this kind of data. Polymer adsorption should also be measured under realistic conditions. If a surfactant is involved, a customized formulation will be developed for the particular field in question, and oil displacement tests will be run to make sure everything works together. Reservoir and laboratory data will go into a computer model for the design of the best flood strategy. A good model will consider such factors as chemical adsorption, reservoir heterogeneity, relative permeability, slug size, changes in polymer concentrations, effects of connate water and residual gas saturations, previous recovery operations, etc. A final project design may require some special tactics to get around some of the reservoir problems indicated in preceding sections. The drilling of additional wells may be worthwhile to get good project efficiency, especially if a surfactant process is involved. Because of the expense, surfactant processes are ordinarily pilot tested. The design of these pilot tests requires close attention to some of the factors illustrated by the model studies.

TABLE 5 TYPICAL LABORATORY TEST DATA SHOWING MOBILITY REDUCTION BY POLYMERS IN FIELD CORE SAMPLES

Polymer Mol. Wt. Grade	Test Water	Core No.	Mobility Decrease at Different Polymer Concentrations 250ppm	500ppm	1000ppm
Medium	Field Brine 6.1 Per cent Solids	1	-	5.5	7.4
		2	-	8.2	10.0
	Supply Water 0.15 Per cent Solids	1	-	20.0	26.4
High	Field Brine 6.1 Per cent Solids	1	-	10.2	18.3
		2	-	13.3	15.0
	Supply Water 0.15 Per cent Solids	1	23.5	29.8	-

POTENTIAL PROBLEMS IN LOW MOBILITY FLOODS

The best engineering and laboratory operation cannot overcome poor operation. A look at some of the possible problems and the ways that have been devised to deal with them will provide some idea of the additional operating requirements called for when mobility control polymers are used.

Problem No. 1: The Injection Wells Plug Up

The usual reason is poor water quality. Insoluble iron compounds ("black" and "red" water) are bad for waterfloods, worse for polymer floods. Additives such as sodium hydrosulfite are used to control ferric hydroxide and corrosion, but black-water problems are best avoided by staying clear of sour brines if possible and controlling sulfate reducing bacteria. Segregation of produced water may be required in some cases. Poor dissolving of the polymer can cause wellbore plugging, but most suppliers have automated equipment that will do the job if it is properly operated and cleaned up occasionally. Xanthan gum solutions may require diatomaceous earth filtration because of the presence of bacterial residues from the manufacturing process.[15]

Problem No. 2: The Polymer Gets Degraded

This can happen on the surface, in the injection well, or in the reservoir. Oxygen is the enemy of the long-term stability of all mobility control polymers, especially at elevated temperatures, and additives will almost always be recommended to deal with this problem. The effectiveness of these additives is quite well established.[16] Figure No. 8 shows some recent unpublished results of laboratory tests which demonstrate the effectiveness of sodium hydrosulfite in stabilizng a commercial polyacrylamide polymer in both salt water and distilled water.[17] Ceiling temperatures for polyacrylamides are about 250° to 300°F and about 150°F for Xanthan gum when stabilizers are used. Polyacrylamide has been used in a 230°F reservoir with good results.[12,13] Xanthan gum can be degraded by some bacteria, and an antimicrobial agent is always used with this polymer. Polyacrylamides are sensitive to "shear" degradation when solutions are passed through regions of high-velocity, rapidly-changing flow. This means that the flow of polyacrylamide solutions cannot be controlled by ordinary values. Control of fluid rate in an injection well which is taking fluid faster than other wells in the system requires one of the following strategies (listed in descending order of preference):

1. Determine the reason for the high flow rate and design a treatment to fix it.
2. Shut the well in part of the time.
3. Use special control devices designed to throttle flow while minimizing polymer degradation.

Polyacrylamide polymers can also be "shear degraded" as they enter the formation if injection conditions are fairly severe. This behavior has been studied in the literature,[19] and suppliers often have laboratory correlation data which will allow them to predict when a wellbore degradation problem is likely to occur. The problem is aggravated by high injection rates, limited formation exposure in the wellbore, heavy brine, and low effective permeability. Solutions to the problem, when it is serious, usually revolve around the development of

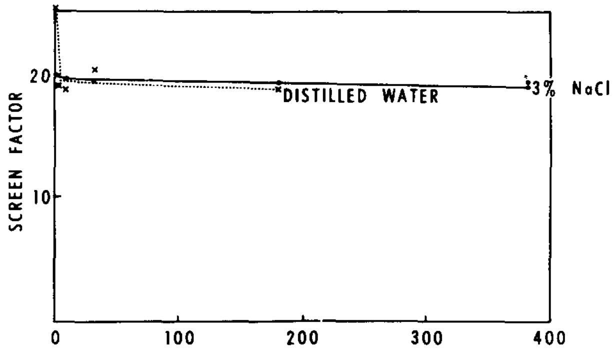


FIGURE 8—ALTERNATE POLYMER/BRINE INJECTION EXPERIMENT

additional sand surface for injection.[18] Open hole completions are always preferable. Special fracturing techniques may be of value; conventional fractures may not be.[19] Natural or induced fractures of limited extent are frequently present to alleviate the polymer degradation problem. These can be detected by suitable well tests.

One proposed solution to the degradation problem is to alternately inject concentrated polymer at a low rate and water at a high rate, with mixing in the formation near the wellbore producing a polymer solution of the desired concentration. Figure No. 9 shows the result of a mixing test in a sand column in which 5,000 ppm polymer and water were alternated to produce a 295 ppm solution. Nine cycles produced good blending. Extrapolation to a 20-acre pattern indicated that the mixing zone would represent 5% of the reservoir if polymer were injected for 5 days and water for 15. The overall rate of injection would be only slightly lower than projected for a 295 ppm polymer solution, yet the polymer concentrate would be injected at only 19% of this rate.

Problem No. 3: Corrosion Rates Increase in Producing Wells

This usually occurs when some polymer is produced in wells which are being treated with cationic inhibitors. The solution to the problem is usually a change to inhibitors compatible with the polymer.

Problem No. 4: Unsuspected Channels Cause Injected Fluids to Move Rapidly to Producing Wells

Routine analysis of produced water is recommended to detect this kind of problem. The

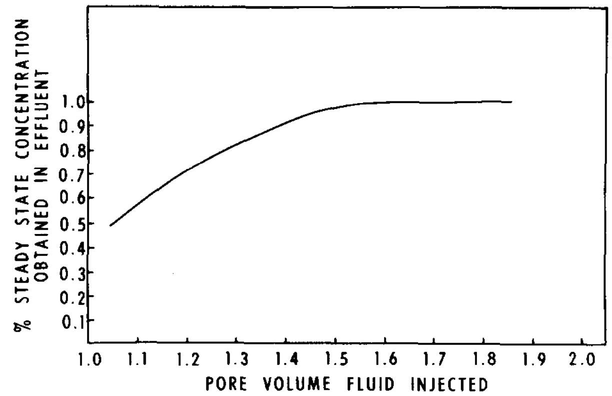


FIGURE 9—THERMAL STABILITY OF HYDROSULFITE STABILIZED HYDROLYZED POLYACRYLAMIDE IN AN OXYGEN-FREE SYSTEM

addition of small amounts of certain chemicals to the polymer solution at the wellheads of the offending injectors may often be a simple solution.[20]

CONCLUSION

The use of mobility control polymers can produce results ranging from dismal failure to the fairly spectacular. The possibility of failure can be reduced by following simple guidelines for avoiding trouble and by using a couple of simple calculations to indicate low potential. The possibility of fairly spectacular results can be indicated by simple calculations and can be given a chance to happen by good operation practices. Really spectacular results may require some fairly spectacular investments. Moderately spectacular results are frequently accessible to most operators. A low-mobility process will always require that the operator accept some extra complications in daily operation and the addition of some new items to his list of things to be careful about.

NOMENCLATURE

f = Fraction of water in flowing fluid
k_o = Relative permeability to oil
k_w = Relative permeability to water
λ_t = Relative fluid mobility
S_w = Saturation of water, fraction of pore space
S_{wro} = Saturation of water at the irreducible oil saturation
μ_o = Viscosity of oil, cps
μ_w = Viscosity of water, cps

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