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Polymer-Augmented Waterflooding and Control of Reservoir Heterogeneity

George F. Schurz, Science Service, and F. David Martin, Randy Seright, and W.W. Weiss, New Mexico Petroleum Recovery Research Center

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Abstract

The use of water soluble polymers in injection brine improves sweep efficiency in waterfloods thus increasing oil recovery. In 1978 a comprehensive review¹ of this use of polymers cited over 100 papers. The present paper reviews activity since that time emphasizing field usage, new application methods, and changing economics.

Introduction

Only about one third of the oil discovered in the United States is recovered by the combination of primary plus secondary oil production. The principal method of secondary oil production is waterflooding, which at present, accounts for more than one-half of all oil production in the United States.^{2,3} Improvements in waterflooding then can substantially improve total U S oil production. Waterflooding is a thoroughly studied process and the factors affecting oil recovery are well delineated. The maximum recovery which might be obtained under any economic condition is of course the total mobile oil available at the start of waterflooding. The actual waterflood recovery is less than this maximum, the amount being determined by physical factors and economic conditions. Physical causes found to determine the practical recovery include injection rate, relative permeability to oil and water, the distribution of permeability in the reservoir, and the water-oil mobility ratio.⁴ Each of the preceding factors may be changed by the incorporation of water soluble polymer in the injection fluid. Such

polymer augmented waterflooding (PAW) is designed to either reduce the permeability of the formation to water, to increase water viscosity, or to obtain some combination of such effects so that sweep efficiency and oil recovery are improved. Improvement in sweep efficiency implies either contacting more of the reservoir with injection fluid or more rapid production of oil per unit of fluid injected, that is, by improved micro displacement.

The preceding is based on the assumption that the only effect of polymers on waterflooding is to improve sweep efficiency but not to change residual oil saturation. This is the usual case, residual oil determined in the laboratory is the same whether a polymer solution or normal waterflood brine is used. Other chemicals, say surfactants or microemulsions, do reduce residual oil saturation. When used to increase oil production many of these other systems require the use of polymer to improve sweep efficiency. The present review does not include a detailed examination of these alternate chemical processes however they will be discussed as economic competitors to PAW. Of course, the general principles of polymer use discussed will be applicable to all processes.

Polymers Used

Two polymers, xanthan gum, and polyacrylamide containing 10 to 30% acrylate groups (HPAM), have been used for PAW. Chemical structures of the products are shown in Figure 1. Viscosity characteristics of typical products are shown in Figure 2. Xanthan yields solutions whose viscosity is little

References and Figures at end of paper.

affected by salinity. On the other hand, the viscosity of HPAM changes dramatically with changes in salinity. The effective viscosity of water soluble polymers flowing through reservoir rock may be higher or lower than the bulk viscosity of the solutions. If a porous media is represented by a simple model such as a bundle of capillary tubes, the polymer viscosity indicated from flow tests is not that observed in bulk tests of the same polymer. Polymer solutions of rigid molecules (xanthan) commonly show lower viscosity than expected. Flexible molecules such as HPAM show higher than expected viscosity. HPAM thus reduces the mobility of water in core tests far more than would be predicted from simple viscosity measurements. The effect, first described by Pye⁵, is quantified by a number, resistance factor. Resistance factor is the pressure ratio, at constant flow rate, comparing flow with water and polymer solution. For fluids where viscosity is the only consideration, the resistance factor and the viscosity value are identical. The question arises as to whether resistance factor is as effective in oil recovery as viscosity. Jennings⁶ published laboratory data showing that solutions of HPAM with high resistance factor recovered additional oil even though their measure bulk viscosity was low. The recovery was similar to that from a Newtonian viscous agent. This work also examined the effect of polymer adsorption and adsorption of polymer by the formation was found to delay incremental oil production. Because of adsorption and because polymer solutions miscibly displace connate brine a water bank forms in front of the polymer so the initial displacing agent in a PAW is always later. Polymer solution lags this water bank by an amount which depends on the polymer adsorption and the initial water saturation. As reported by Jennings, these factors can delay the beneficial effect of polymer.

The large size of the polymer molecule used for mobility control may make it impossible for the polymer to penetrate some of the smallest openings in the formation matrix. Studies using very fine filters have shown that a given polymer will penetrate say a 1.2 micron filter but be restrained by finer pores. Dawson⁸ conducted the first systematic study of this effect in reservoir core material. The polymer is excluded from portions of the reservoir while small molecules can enter all permeable sand sections. The polymer molecules therefore traverse a smaller void space and emerge before small molecules. Pore size and shape are important factors in excluded volume effects. It has also been found that hydrodynamic forces reduce polymer concentration in the region adjacent to the pore walls⁹. These excluded volume effects mitigate adsorption to some extent and permit more rapid penetration of the reservoir by the polymer. Usually, in PAW

adsorption is the more powerful effect and is sufficient to cause polymer to lag the injection front. In chemical floods however, polymer may lead the injection front because of reduced adsorption.

Stability of Polymers Under Conditions of

Application of polymer in PAW requires that the polymer be stable for several years under reservoir conditions. Damage to polymer occurs in several ways. During injection, high shear rates near the injection well can cause polymer degradation. Chemical reactions can change the base polymer, HPAM for example is subject to hydrolysis converting amide groups to acrylate. Chemical attack may also break polymer chains reducing polymer molecular weight. Finally bacterial attack may result in damage to the polymer.

Shear degradation is unlikely with xanthan gum but is of concern when using HPAM. In fact, the low viscosity of xanthan gum solutions at high shear makes injection easier and constitutes a significant advantage for this product. HPAM on the other hand may be degraded at the injection well. Studies by Maerker¹⁰ and by Seright¹¹ examined the problem, offered methods of predicting injection rates for polymer solutions, and determined the extent of degradation to be expected. Degradation is at a minimum in fresh water and is increasingly severe as salinity of the injection brine increases. Degradation is particularly sensitive to the presence of hardness ions. Application of polymers must be conditional on being able to inject without excess damage either to the polymer or to injection rate. While laboratory study is of value, the most certain method of determining this is by a field injection trial. Tests usually involve injection followed by back production of polymer. Thus in the Stanley Stringer quality retard on was better than expected¹². By the use of such a field injectivity test Weiss¹³ determined mobility control when cores were not available for laboratory tests.

Chemical degradation, that is loss of molecular weight by chemical reaction, has been extensively studied with both polymers. A major factor in preventing degradation is absolute elimination of oxidizing agents such as air from solutions. Normal practice is to add a chemical reducing agent, typically sodium hydrosulfite, to provide complete oxygen removal. Under these conditions polymer remains stable for indefinite periods even at high reservoir temperature. Thus at pH 7 and temperature of 80°C (176°F) Seright¹⁴ estimated from rate studies that xanthan would retain 50% of its initial viscosity for 5 year period if dissolved in brine. In fresh water and at pH other than seven xanthan degrades more rapidly. HPAM was tested by Mc Williams¹⁵ and under air

free conditions shown to retain 90% of its initial viscosity after one year at 200° F. At a temperature of 50°C Knight¹⁶ showed that formaldehyde, at the 200 ppm level, was a good stabilizer for HPAM even in the presence of oxygen. Since formaldehyde also acts as a bacteriostat the combination has been often used in the field.

Chemical change, apart from loss of molecular weight is also possible. Thus, xanthan is subject to deacetylation which changes its structure without necessarily harming its mobility control capability. HPAM, on the other hand, may suffer hydrolysis of amide groups converting them to acrylate groups. A high degree of conversion makes the polymer subject to precipitation by hardness ions, calcium or magnesium. Since calcium is ubiquitous in reservoirs this is a very damaging reaction. For this reason, HPAM is normally considered applicable only at temperatures below about 160° F where the hydrolysis reaction may be slow enough to provide acceptable life for the polymer.¹⁷

Bacterial attack on the polymers may also cause loss of mobility control. Xanthan is apparently more susceptible than HPAM to such loss and the structures of the two products indicate such should be the case. Surfactant flood tests which had monitor wells showed in several cases that xanthan was destroyed in the field.¹⁸ After experiencing problems in one such field application, study indicated that xanthan preservation could be accomplished by using very high concentrations of formaldehyde, say 1500 ppm. At such levels the formaldehyde essentially sterilized the solution and resulted in good retention of quality. Whether such treatments need to be continuous or only used intermittently is open to question. Also, since formaldehyde is a small molecule, excluded volume effects may cause separation of xanthan from formaldehyde in the reservoir. This factor of course applies to most other biocides as well.

Alternate or New Polymers

The deficiencies listed for xanthan and HPAM have led to a search for polymers or other materials which might replace the current products. Norton¹⁹ studied most common water soluble polymers singly and in combinations hoping to find superior performance. While some synergisms were observed there was not sufficient improvement to lead to usable systems with existing materials. There has also been a continuing effort to produce new products with improved properties.

Two of the more interesting efforts may be mentioned. Doe²⁰ reported that copolymers of acrylamide and other monomers, particularly vinyl pyrrolidone, showed resistance to hydrolysis and precipitation at high temperature. The creation of a structure of alternating monomers is known

to alter the properties of each monomer unit in the polymer chain.²¹ In the products discussed by Doe such alternation apparently limits the hydrolysis of the acrylamide unit and prevents precipitation by calcium ion. Mc Cormick et al²² has prepared products of moderate molecular weight which tend to associate in brine solution. The products are of low viscosity when dissociated but when combined into high molecular weight products show the high viscosity expected from that molecular weight. It is proposed that the molecules will dissociate under the high shear experienced at the injection well. Consequently injection will be expedited. At the low shear experienced in the body of the reservoir the product will again associate giving good mobility control. Whether low cost, low adsorption, products of this type can be produced remains to be determined.

Application to the Individual Field

Core tests measure mobility control effects on a microscopic scale. The effect on oil recovery of such changes in mobility can be assessed by reservoir simulators. Such simulations have progressed from simple examination of the effect of viscosity change on recovery to modeling the effect of possible chemical reactions, cross flow, and complex viscosity functions on PAW.²³ With the increasing sophistication of such modeling, errors in the earlier projections of additional oil recovery by PAW should be detected. This has not occurred, current projections are for the most part quite similar to those of earlier models. These powerful calculation tools are an indispensable aid in evaluating the benefit of mobility control to waterflooding.

For preliminary examination of fields, prior to the use of a simulator, it is possible to approximately calculate recovery by hand.²⁴ Recently simple computer programs have become generally available to replace hand calculation. One such program was developed by the National Petroleum Council for its 1984 survey of Enhanced Oil Recovery potential in the United States²⁵. The program cited permits rapid calculation of PAW using only desk top model computers. Typical run time is less than 5 minutes using a computer operating at 5 MHz with an Intel 80286 cpu, 80287 math chip and 640 K of RAM. The program is distributed free of charge by the US DOE. In addition to the oil recovery estimation this program outputs an economic projection. These simple calculation methods are not sufficiently rigorous to permit actual project design. Instead they are useful screening tools which are capable of selecting good field candidates and rejecting unlikely prospects. Data input for either is similar to that needed for the final simulation. The hand calculation has value in offering insight into what is happening

but it is slower and for more than a single field is excessively time consuming.

Fractured Reservoirs

Polymer flow behavior in fractured reservoirs is quite different from application in normal permeable rock. In fractures the non Newtonian polymer solutions have low viscosity and are ineffective in controlling flow. If natural fractures exist, which are short relative to the well spacing, polymer use may be beneficial. Flow control then can occur in the formation adjacent to the fractures. For non packed fractures which communicate from well to well polymers solutions have little value. To control flow under these conditions polymer in the form of a cross-linked insoluble gel may be utilized. The same polymers used for mobility control are commonly used to prepare the gels for control of flow in fractures. Other polymers produce similar gels but have been less used for this purpose. The advantage of the gel treatment over other methods of sealing fractures is the depth of penetration presumably obtained by using the soft gel. Bypassing of the blocking agent is less likely if penetration in depth can be achieved.

Routson²⁶ offered data on project applications in which severe channeling occurred through fractures. Fractures were identified by very rapid transit times for tracers. Polyacrylamide gel formed by cross-linking soluble polymer with chromic ion was applied to block flow in the fracture and as shown by additional tracer studies was successful. Retreatment was necessary in one case before permanent blockage was obtained. Water cut reduction and oil production gains were reported as a result of the treatment. Prior to fracture blockage, water flowing through the fracture had not been displacing oil. Once the fracture was closed injected water was diverted to oil producing areas. As a result, oil production increased in both the production well connected to the fracture and in adjacent wells.

Subsequent to this demonstration, extensive use of polymer gels for control of water flow has developed. The principal cross linking agents used have been the aluminum ion, normally furnished as aluminum citrate, or trivalent chromium. The trivalent chromium is often prepared by mixing the polymer solution with dichromate ion then using a suitable reducing agent to prepare the trivalent ion. Extensive research on methods of preparing the trivalent chromium has developed processes²⁷ which delay gelation so that the gel is formed long after injection and at great depths into the formation. Gelled polyacrylamide is essentially immobile and cannot be injected into formations of low to moderate permeability. Gelation in situ permits treatment of formation as well as fractures.

Xanthan is also gelled by trivalent chromium however the gel is much more reversible to shear. Under high shear the gel reverts to a low viscosity fluid and when shear is reduced the gel reforms. This permits xanthan to be used as a preformed gel which can be injected at high shear and minimum viscosity. Xanthan gel therefore can be used in formation as well as in fractures without the complication of a chemical reaction to delay gelation.

Laboratory Tests

Use of mobility control agents is predicated on laboratory tests using cores and fluids from the field concerned. Foshee²⁸ has presented procedures for the conduct of the specialized tests needed. Considerable care is required to obtain valid results. The initial information needed is the apparent viscosity of the polymer solution at varying concentration and flow conditions as well as the retention of polymer by the core.

Testing chemically identical polymers of varying molecular weight will show that products of higher molecular weight have greater viscosity in solution and higher resistance to flow in cores. Pore size in the core places an upper limit on the molecular weight of the polymer used. Products of excessively high molecular weight may be completely filtered from solution. Within each polymer sample however lie a wide range of molecular weights some of which may be close to the point of being filtered from the solution. Also it is possible that the polymer contains small amounts of insoluble or slowly soluble material. These factors may lead to reduction in injection rate above that expected on the basis of mobility change alone. Such problems have led to the use of xanthan gum in the broth or solution form in spite of the high shipping cost associated with these dilute solutions. Similarly, field manufacture of HPAM is reported to yield a product with better injectivity than commercial products.²⁹ It was of interest to study this problem since it has appeared at a large number of installations. Filtration studies of the type reported by Gogarty⁷ were chosen as the test method however it appeared desirable for this purpose to use filters other than those used by Gogarty. Because interaction between rock and polymer are important factors in both flow and filtration behavior plastic filters were rejected. Glass fiber filters were selected for the tests. While certainly far from identical to reservoir rock, these filters offer a tortuous flow path and are available free of plastic binders. The products used were Whatman grade GF/D which have a nominal retention of 2.7 u. Tests at pressures from 5 to 20 psi across the filters showed little or no shear degradation during filtration. The higher pressure was used in most of the study since it saved time. Tests on polymer free

brine which had been filtered through a 0.45 μ membrane filter are shown in Figure 3. Little plugging is shown under these conditions but there is some difference in rate between individual filters even from the same lot. The differences in rate are undesirable but not critical to the testing since comparison of the initial filter rate with the rate at later times is used as the measure of plugging. Data was fitted to a polynomial using a least squares fit program. Three or four terms adequately fitted the data.

$$1) T = aC + bV^2 + cV^3 + dV^4 \dots$$

Differentiating the above equation and examining the value at zero time shows that the constant a is a measure of the resistance factor of the solution in the glass filter before plugging. We may expect this to correlate in some fashion with resistance to flow in reservoir rock. Higher terms in the equation are plugging factors for the solutions used. A run on a widely used dry commercial product is shown in Figure 4. Solution viscosity before and after filtration as well as screen factors for the solutions are shown. Viscosity measurements were made with a Brookfield viscometer at 6 μ l. Composition of the "fresh" water used in the test is shown in Table 1. The composition approximates a water used in waterfloods in east Texas and north Louisiana. It is clear that plugging is occurring with the product under the test conditions. Also as shown in Figure 5 the filtration is removing small amounts of plugging material. Polymer solution viscosity and screen factor change by trivial amounts but filtration behavior improves. This was somewhat surprising since tests years earlier in brines had shown the product to inject quite readily.³⁰ Tests in 3% NaCl brine were repeated on the product with the results shown in Figure 6. In brine the degree of plugging is far less than in the fresh water used in the first test. While this is not surprising in view of the properties of HPAM it made clear why after many years of successful use of this specific product it was being found damaging to injection at a number of locations. Prior use of PAW was for the most part in floods using brine as the injection medium. The surfactant floods started at about this time were often in fresh water as were a significant number of the PAW operations.^{31 32} This led to greater sensitivity to plugging materials in the polymer than previously. The question as to how best to cope with fresh water systems had several possible answers. Among these were:

a - Introducing more shear while preparing the polymer solution. This might selectively destroy plugging materials.

b - Selective chemical degradation of the plugging materials.

c - Reducing the molecular weight of the products.

d - Locating alternate products which filtered adequately without treatment.

The effect of shear during polymer dissolution was determined by comparing solutions prepared on a laboratory mixer with little or no shear with solutions sheared quite strongly on a Waring blender. The higher shear rates gave improved filtration but at a high loss in solution screen factor which is synonymous with a loss in mobility control. Data on the runs made is shown in Figure 7. The data indicates that for preparing solutions the use of a propeller with a shroud (Jiffy Mixer) operated for one minute at 600 rpm and followed by minimum agitation gave the best combination of good filtration behavior plus solution quality. The product tested in this case was an emulsion product however similar behavior was observed for solid materials. The solution made up on the magnetic mixer had the highest viscosity and screen factor but had poor filtration behavior. The solutions made up on the Waring blender were held for one minute with the blender operating at either 55 or 110 volts. It appears that shear, at least as introduced by a Waring blender, is not a good method of improving filtration properties. The improved filtration occurs at a high cost in terms of solution quality. Coefficients of equation 1 are listed in Table 2 for these runs. Chemical degradation showed much poorer response than mechanical degradation. There remains some chance that mechanical degradation under other conditions might improve results over those shown. It would be of interest to test degradation in thin sheets of porous media or in fine mesh screens. Our attention was diverted from this possibility by the discovery that some commercially available samples had much better filtration behavior. Examination of a large number of products led to a significant group which had excellent filter characteristics. Filter behavior of a good solid product is shown in Figure 8, and of a good emulsion product is shown in Figure 9. As an indication that the filter tests are a useful guide to behavior in the field we were able to obtain a sample of material prepared by a field polymerization process and confirmed that the product gave a filter performance equivalent to the good products shown above. The field manufactured product is reported to show better performance in the field than commercial products previously used.³³ Also a sample from a field operation which had shown poor injectivity yielded the behavior shown in Figure 10. There is the some correlation between filter testing and reported field behavior. The limited number of examples in our experience of course makes this correlation tentative at present.

POLYMER FLOODING FIELD ACTIVITY

Discussion to this point has emphasized the theoretical utility of polymer flooding. However a process in existence for many years should have a successful field use history. At least **three polymer floods were underway as early as 1961. Since then more than 300 polymer floods have been implemented.** Manning et al.³⁴ conducted a very complete study of 226 project listings for polymer floods that were initiated prior to 1983. At the peak of EOR activity, the Oil and Gas Journal³⁵ listed 178 active polymer projects. Polymer floods have been field tested under an incredibly wide range of conditions (see Table 1).

Since polymer flooding is often stated to be the least complex EOR process, one might expect a fairly good definition of where polymer flooding does and does not work -- especially after thirty years of extensive field testing. One might also expect the chronology of field activity to reflect refinement in where and how polymer floods are applied. With this in mind, Table 4 compares median values for key polymer flooding properties from Manning's 1983 study with those of a new study that was conducted by one of the authors. Manning's study covers the first twenty years of polymer field activity, while the new study focuses on the past ten years. Table 4 also includes data from three recent polymer floods that were conducted outside the United States.^{36 37 38} These projects were included for three reasons. First, their incremental oil recovery due to polymer flooding is among the highest of all projects. Thus, they provide good examples of conditions where polymer flooding will work best. Second, the projects are well documented. Third, because they were conducted outside the United States, they were not directly influenced by the U.S. tax policy.

One interesting fact to emerge from Table 4 is that the median oil/water viscosity ratio for field projects has been relatively low--6.8 from the Manning study and 5.4 from the new study. This means that the water/oil mobility has been favorable (less than one) or near favorable for half of all projects prior to polymer flooding. In contrast, the three individual projects listed in Table 4 all had very high oil/water viscosity ratios and mobility ratios.

Both the Manning survey and the new survey reveal that polyacrylamides have been used far more often than xanthan (by ratios of 19:1 and 11:1 respectively). This has occurred in spite of the fact that 80 percent of the projects involved reservoirs with resident brine salinities greater than one percent total dissolved solids (TDS). This reflects a widespread reliance on two assumptions that have been the subject of ongoing debate. The first assumption is that a low-salinity preflush and/or a low-

salinity polyacrylamide bank will be effective in spite of the saline reservoir water. A second assumption is that problems associated with polyacrylamide use (mechanical degradation, salinity and divalent-ion intolerance, injectivity, and field-handling problems) are less severe than problems associated with xanthan use (higher-cost, microbial degradation, injectivity and field-handling problems).

Field activity in polymer flooding reflects a general concern that polyacrylamide and xanthan polymers do not have sufficient stability for use in high-temperature reservoirs. Only seven percent of the projects in the Manning study and 12 percent of the projects in the new study have reservoir temperatures above 75°C.

The median permeability for polymer floods has always been low, and Table 4 suggests that it is decreasing. Part of this decrease may be attributed to the increased frequency of floods in less-permeable carbonate reservoirs. (The ratio of floods in sandstone reservoirs to carbonate reservoirs dropped from 10:1 to 2.2:1 in recent years.) Thus, the ability of polymers to propagate through low permeability rock has grown in importance.

An issue related to reservoir permeability is that of injectivity. Injectivity problems has often been reported during field projects. General agreement exists that water quality, polymer dissolution and microbial growth are important factors that impact injectivity. However, a debate exists concerning the utility of injection above the formation parting pressure to improve polymer injectivity. Especially for concentrated polymer solutions, injectivity is expected to be significantly less for polymer solutions than for water. If an injector is fractured, will the increased injectivity outweigh the increased risk of channeling? Also, will a shear-thinning xanthan solution have a significantly greater injectivity than a shear-thickening polyacrylamide solution?

Table 4 shows that the median polymer concentration during polymer injection has increased significantly in recent years. This reflects a greater reliance on reducing water mobility through viscosity increase rather than permeability reduction. The median number of pounds of polymer injected per acre-foot has increased by about 67 percent.

Table 4 lists three different types of projections of incremental oil recovery (over projected waterflood recovery)-- $\frac{1}{2}$ OOIP, bbl oil/lb polymer, and bbl/ac-ft. For all three types, the median projections of incremental recovery are less for the 1980-1989 period than for the earlier period. The three individual projects listed have dramatically higher levels of incremental $\frac{1}{2}$ OOIP and bbl oil/ac-ft. However, a substantially greater quantity

of polymer was injected (per acre-foot) for these three projects. Based on the incremental barrels of oil per pound of polymer, the superiority of the three individual projects is less obvious. Even so, these projects clearly show that polymer floods can dramatically improve oil recovery under the right circumstances. The high levels of incremental oil recovery provide a convincing demonstration of the benefits of polymer flooding. Too often in the past, the response from a given polymer flood has been too small to quantify without considerable ambiguity.

Finally, as with all EOR processes, improvements in reservoir description are needed. Very often, some wells in a given project respond much better to the EOR process than others. Improved reservoir description may help establish where and how a particular process can be applied most effectively.

FIELD ACTIVITY WITH CROSS-LINKED POLYMERS

Cross-linked polymer treatments (gel treatments) were developed to reduce channeling of fluids through fractures and streaks of very high permeability. These treatments have been successfully applied to both injection wells and production wells. The success in injection wells has been demonstrated in the North Stanley polymer flood. Here, gel treatments were applied to plug fractures prior to implementing a traditional polymer flood.³⁹ A large portion of the tertiary oil recovered in this project was attributed to the gel treatments rather than to the polymer flood. Gel treatments in production wells have worked particularly well in reducing water coning in the bottom-water-drive Arbuckle reservoirs of Kansas.⁴⁰ Gel treatments have also been applied to reduce channeling in miscible floods.^{41 42} Near-wellbore applications of cross-linked polymer treatments in injection wells experienced explosive growth between 1980 and 1986. This growth can be largely attributed to the Windfall Profits Tax Act of 1980. Table 5 provides median properties for 127 injection-well treatments that were applied in the 1980's. Table 3 also lists the extremes under which this technology has been implemented.

Applications of cross-linked polymer technology can be contrasted with those of traditional polymer floods by comparing Tables 4 and 5. The median water/oil ratio (WOR) at project start-up for cross-linked polymer treatments is over twice the value for traditional polymer floods. Higher WOR values reflect the more severe channeling problems in cross-linked polymer candidates.

Compared with traditional polymer floods, cross-linked polymer treatments are more likely to use xanthan and are less likely to be used in carbonate reservoirs. No

technical reason is apparent. The median polymer concentration for cross-linked polymer treatments is three times greater than that for traditional polymer floods. This is not unexpected, since high polymer concentrations are needed for gel formation. The median number of pounds of polymer injected per acre-ft of reservoir is dramatically less for gel treatments than for traditional polymer floods (4 vs 30 lbs/ac-ft). This was expected since gel treatments usually have involved small fluid volumes.

In terms of % OOIP and bbl oil/ac-ft, the median incremental oil projected for cross-linked polymer treatments is roughly half that for traditional polymer floods. However, when expressed as bbl oil/lb polymer, the median incremental oil recovery projected from cross-linked polymers is almost twice that for traditional polymer floods. Because of the Windfall Profits Tax Act, implementation of gel treatments was influenced as much or more by tax considerations as by technical factors. Thus, additional effort will be required to sort out how and where these treatments are best applied.

conclusions

Over a wide range of conditions, waterfloods augmented by the use of polymers show improvement in oil production.

The use of polymers in waterflooding was greatly stimulated by tax incentive programs.

The economics of using polymer depend on normal cost factors plus the amount of reduction in injection rate suffered from polymer use. Polymer selection therefore is an important factor in polymer economics.

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Table 1.
Make Up of Synthetic Fresh Water

Material	Amount (gm/l)
NaHCO ₃	.303
Na ₂ CO ₃	.055
CaCl ₂ ·2H ₂ O	.011
MgCl ₂ ·6H ₂ O	.0084
NaCl	.105
Na ₂ SO ₄	.003

Carbonates and the remaining components are dissolved separately then combined. Solution ph is adjusted to 6.9 with dilute HCl.

Table 2.
Constants in Empirical Curve Fit

Condition	a	b	c	d
Mag Mixer	0.5778	1.75x10 ⁻³	-4.1x10 ⁻⁷	9.44x10 ⁻¹⁰
Jiffy Mixer	0.661	5.74x10 ⁻⁴	-1.2x10 ⁻⁷	1.36x10 ⁻¹⁰
Waring 55v	0.472	5.04x10 ⁻⁴	3.2x10 ⁻⁸	6.0 x10 ⁻¹²
Waring 110v	0.259	7.5 x10 ⁻⁸	1.3x10 ⁻¹⁰	9.0 x10 ⁻¹¹

Table 3*
Range of Conditions Under Which Polymer Floods Have Been Initiated

<u>Property</u>	<u>Minimum</u>	<u>Maximum</u>
Oil viscosity (cp)	0.072	1494
Temperature (°C)	8	113
Average Permeability (md)	1.3	15,000
Average Porosity	0.06	0.38
Resident brine salinity (% TDS)	0.3	21.3
Oil saturation at start-up	0.31	0.89
Producing water/oil ratio at start-up	0	100
Net pay (ft)	4	432

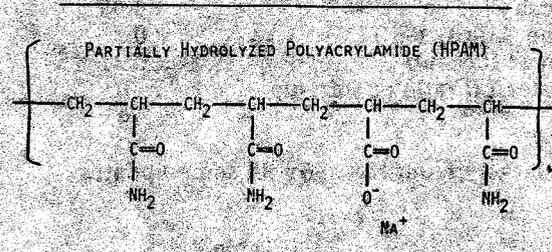
* Data taken largely from Ref. 36 with some updates.

Table 4
Properties of Polymer Flooding Field Projects

	<u>Median Values From Surveys</u>		<u>Selected Individual Projects</u>		
	<u>1960-1982¹</u> <u>(226 proj.)</u>	<u>1980-1989</u> <u>(99 proj.)</u>	<u>Marmul³</u>	<u>Oerrel^{4,5}</u>	<u>Courtenay⁶</u>
<u>Reservoir & Fluid Properties</u>					
Oil/water viscosity ratio at reservoir temperature	6.8	5.4	114	39	55
Reservoir temperature (°C)	46	46	46	58	30
Permeability (md)	101	54	15,000	2000	2500
% OOIP present at start-up	74.6	74	≈92	81.5	≈69
Producing WOR at start-up	2.4	5.0	1	4	4
Lithology (sand:carbonate)	10:1	2.4:1	sand.	sand.	sand.
<u>Polymer Injection</u>					
Polymer (HPAM:Xanthan)	19:1	11:1	HPAM	HPAM	HPAM
Polymer concentration (ppm)	250	500	1000	1500	1000
lbs polymer/ac-ft	19.2	32	373	162	536
<u>Projected Incremental Recovery Over Waterflooding</u>					
% OOIP	4.8	3.7	25	≈13	≈14
bbl oil/lb polymer	1.3	0.64	1.2	≈1.4	≈0.5
bbl oil/ac-ft	25	20.5	461	≈230	≈290

Table 5
Properties of 130 Field Projects Involving Polymer Gel Treatment in Injection Wells (1980-1989)

<u>Reservoir & Fluid Properties</u>	<u>Median</u>	<u>Minimum</u>	<u>Maximum</u>
Oil/water viscosity ratio at reservoir temperature	8.4	0.65	280
Reservoir temperature (°C)	49	18	116
Permeability (md)	100	4.1	5000
% OOIP present at start-up	76.1	27.4	98.9
Producing WOR at start-up	10.8	0	160
Lithology (sand:carbonate)	4.4:1		
<u>Polymer Injection</u>			
Polymer (HPAM:Xanthan)	2.3:1		
Polymer concentration (ppm)	1527	100	8600
Lbs polymer/ac-ft	3.8	0.01	127
<u>Projected Incremental Recovery Over Waterflooding</u>			
% OOIP	2.0	0.01	25
bbl oil/lb polymer	2.4	0.15	560
bbl oil/ac-ft	12.2	0.09	215



XANTHAN GUM STRUCTURE

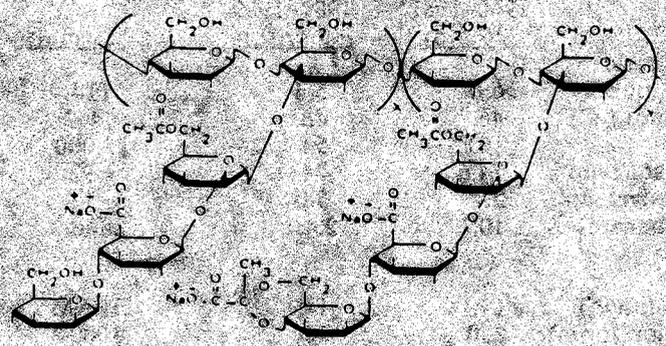


FIG. 1 STRUCTURE OF POLYMERS

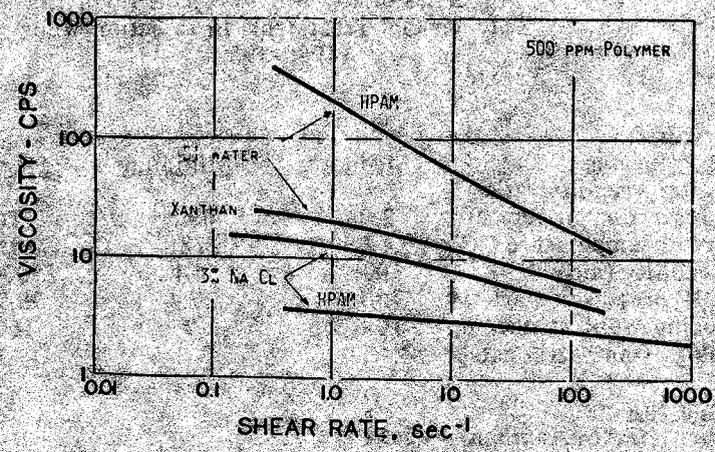


FIG. 2 POLYMER SOLUTION VISCOSITY

Table 3*
Range of Conditions Under Which Polymer Floods Have Been Initiated

<u>Property</u>	<u>Minimum</u>	<u>Maximum</u>
Oil viscosity (cp)	0.072	1494
Temperature (°C)	8	113
Average Permeability (md)	1.3	15,000
Average Porosity	0.06	0.38
Resident brine salinity (% TDS)	0.3	21.3
Oil saturation at start-up	0.31	0.89
Producing water/oil ratio at start-up	0	100
Net pay (ft)	4	432

* Data taken largely from Ref. 36 with some updates.

Table 4
Properties of Polymer Flooding Field Projects

<u>Reservoir & Fluid Properties</u>	<u>Median Values From Surveys</u>		<u>Selected Individual Projects</u>		
	<u>1960-1980¹</u> (226 proj.)	<u>1980-1989</u> (99 proj.)	<u>Marmul³</u>	<u>Oerrel^{4,5}</u>	<u>Courtenay⁶</u>
<u>Oil/water viscosity ratio at reservoir temperature</u>	6.8	5.4	114	39	55
<u>Reservoir temperature (°C)</u>	46	46	46	58	30
<u>Permeability (md)</u>	101	54	15,000	2000	2500
<u>% OOIP present at start-up</u>	74.6	74	≈92	81.5	≈69
<u>Producing WOR at start-up</u>	2.4	5.0	1	4	4
<u>Lithology (sand:carbonate)</u>	10:1	24:1	sand.	sand.	sand.
<u>Polymer Injection</u>					
<u>Polymer (HPAM:Xanthan)</u>	19:1	11:1	HPAM	HFAM	HPAM
<u>Polymer concentration (ppm)</u>	250	500	1000	1500	1000
<u>lbs polymer/ac-ft</u>	19.2	32	373	162	536
<u>Projected Incremental Recovery Over Waterflooding</u>					
<u>% OOIP</u>	4.8	3.7	25	≈13	≈14
<u>bbl oil/lb polymer</u>	1.3	0.64	1.2	≈1.4	≈0.5
<u>bbl oil/ac-ft</u>	25	20.5	461	≈230	≈290

Table 5
Properties of 130 Field Projects Involving Polymer Gel Treatments In Injection Wells (1980-1989)

<u>Reservoir & Fluid Properties</u>	<u>Median</u>	<u>Minimum</u>	<u>Maximum</u>
<u>Oil/water viscosity ratio at reservoir temperature</u>	8.4	0.65	280
<u>Reservoir temperature (°C)</u>	49	18	116
<u>Permeability (md)</u>	100	4.1	5000
<u>% OOIP present at start-up</u>	76.1	27.4	98.9
<u>Producing WOR at start-up</u>	10.8	0	160
<u>Lithology (sand:carbonate)</u>	4.4:1		
<u>Polymer Injection</u>			
<u>Polymer (HPAM:Xanthan)</u>	2.3:1		
<u>Polymer concentration (ppm)</u>	1527	100	8600
<u>Lbs polymer/ac-ft</u>	3.8	0.01	127
<u>Projected Incremental Recovery Over Waterflooding</u>			
<u>% OOIP</u>	2.0	0.01	25
<u>bbl oil/lb polymer</u>	2.4	0.15	560
<u>bbl oil/ac-ft</u>	12.2	0.09	215

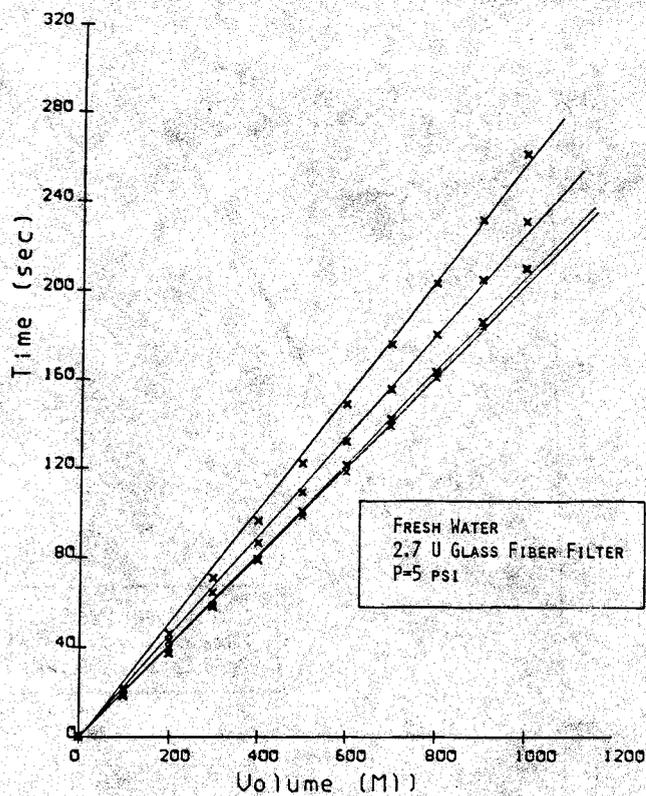


FIG. 3 FILTER REPRODUCIBILITY

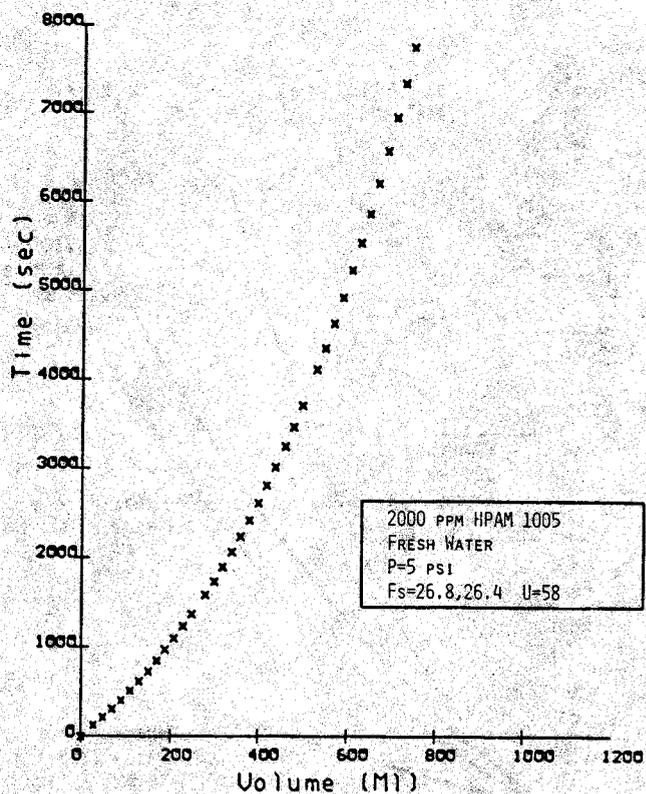


FIG. 4 FILTRATION OF COMMERCIAL DRY PRODUCT

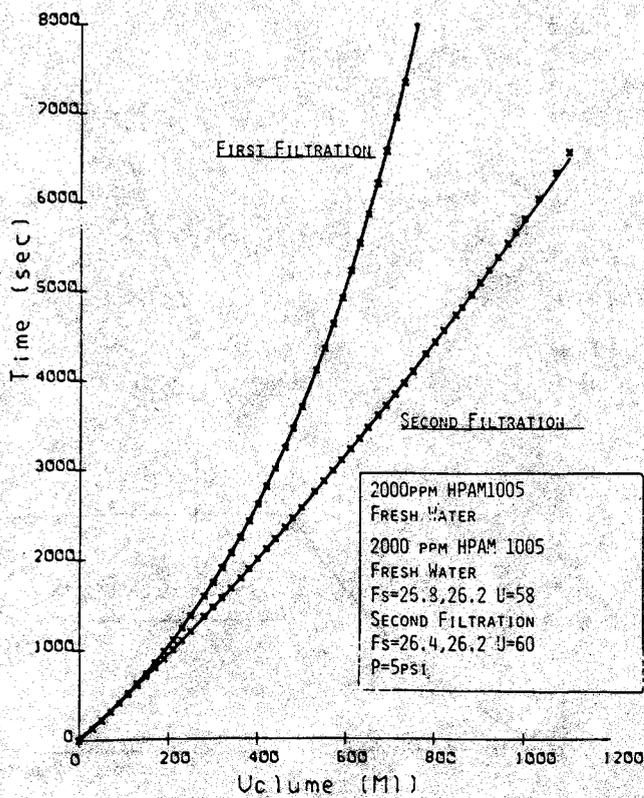


FIG. 5 EFFECT OF PRIOR FILTRATION

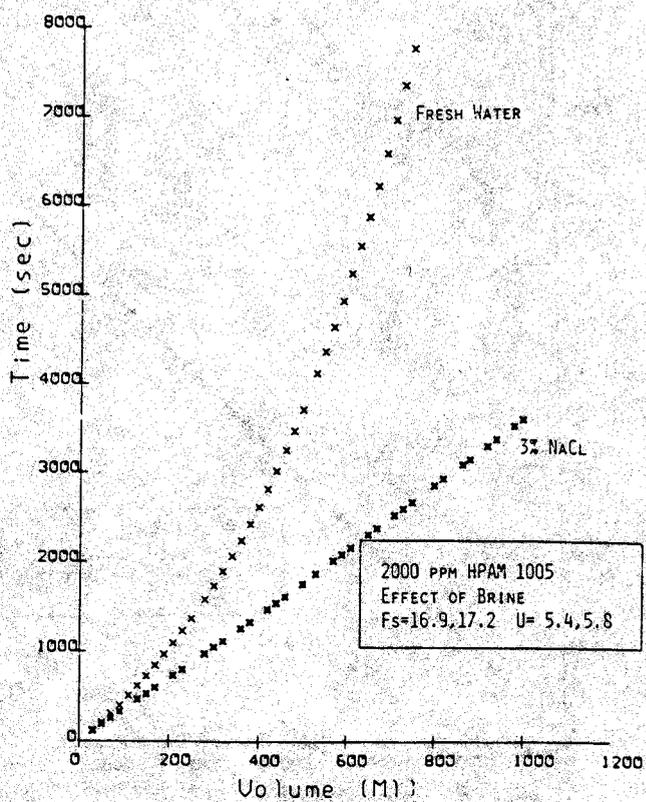


FIG. 6 EFFECT OF SALINITY

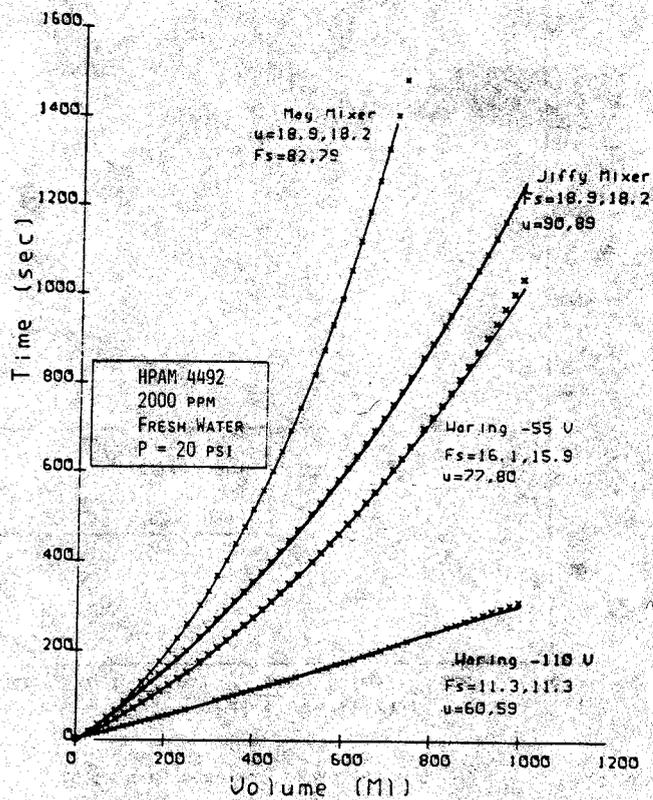


FIG. 7 EFFECT OF SHEAR

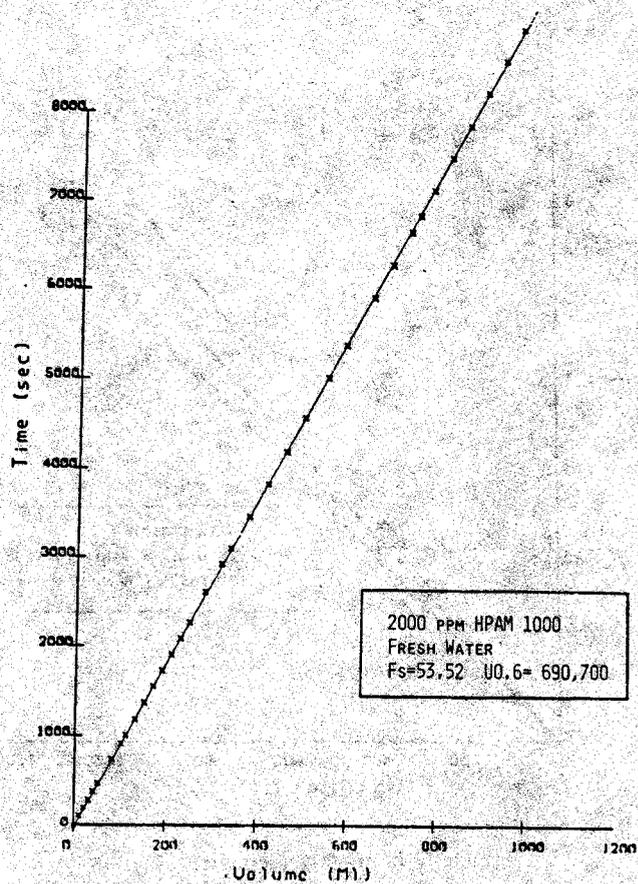


FIG. 8 HIGH QUALITY DRY PRODUCT

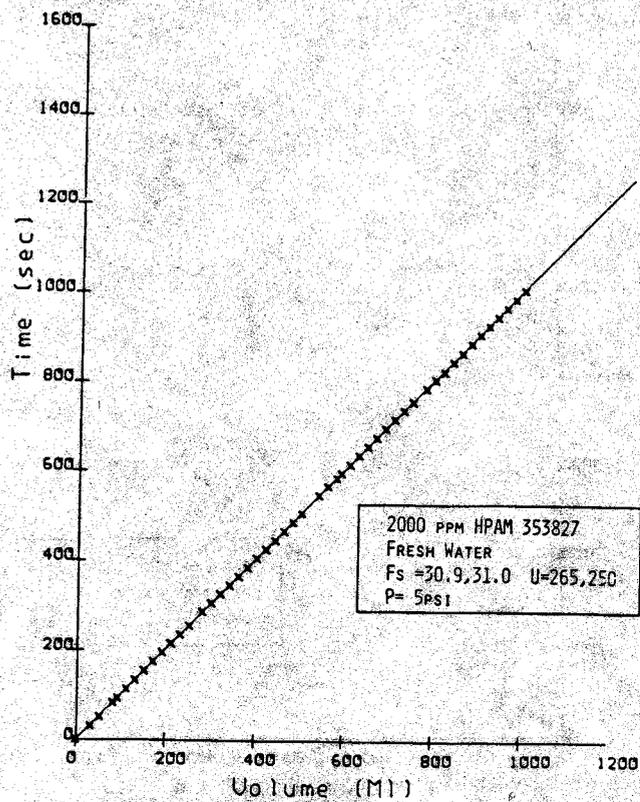


FIG. 9 HIGH QUALITY EMULSION PRODUCT

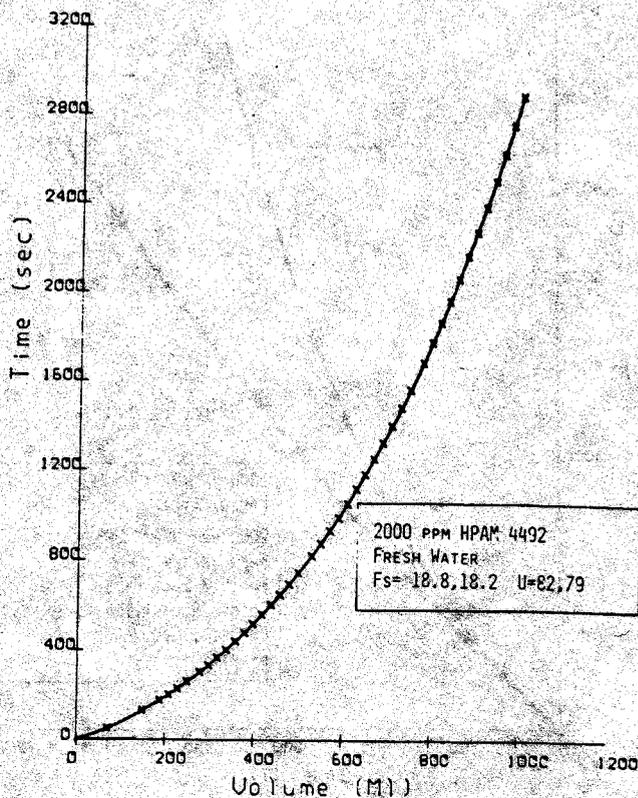


FIG. 10 PRODUCT WITH POOR FIELD PERFORMANCE