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A Survey of Field Applications of Gel Treatments for Water Shutoff

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ABSTRACT

Previously published field results were examined to determine if they reveal usable guidelines for the selection of wells as candidates for gel treatments. Views of seven gel vendors and experts from eight major oil companies were also examined concerning the selection and implementation of gel treatments in injection and production wells.

This study demonstrates that gel treatments have been applied over a remarkably wide range of conditions. Unfortunately, the success rates for these projects have been very sporadic. Our analysis indicates that the producing water/oil ratio was usually the only criterion used to select candidate wells.

To improve the success rate for future gel applications, the source and nature of the water production problem must be adequately identified. Results from interwell tracer studies and simple injectivity and productivity calculations can be especially useful in this diagnosis. Recovery calculations should indicate that considerable mobile oil remains that could be recovered more cost-effectively if a blocking agent could be realistically placed in the proper location.

Improvements are needed in the methods used for sizing gel treatments. The method of sizing should be tailored to the type of channeling problem encountered. Five different types of channeling problems are discussed.

References and illustrations at end of paper

INTRODUCTION

A large number of gel treatments have been applied with the objective of improving reservoir sweep efficiency.¹ With this extensive field experience, one might expect conditions where this technology does and does not work to be fairly well defined. However, considerable uncertainty still exists concerning how and where gel treatments are best applied. While many projects have been very successful,²⁻⁶ many other projects have been technical failures. Two studies indicated that less than 45% of the gel treatments were successful.^{7,8}

In this paper, we investigate whether published field results reveal usable guidelines for the selection of candidates for gel treatments. Views of seven gel vendors and experts from eight oil companies are also examined concerning the selection and implementation of gel treatments. After analyzing the literature and survey responses, we propose criteria for candidate selection, both for injection and production wells.

LITERATURE REVIEW OF FIELD APPLICATIONS

Our review of the petroleum literature included 114 injection-well gel projects (involving more than 3500 wells) and 171 polymer floods that were planned and/or implemented during the 1980s. The literature that provided the information for this survey is listed in Appendix A of Ref. 9. The information was obtained from over 600 articles and reports from 21 different journals and organizations. We also found 274 field applications of polymers and gels in production wells that were

reported during the 1970s and 1980s. The literature that describes these applications is listed in Appendix B of Ref. 9.

Distinction Between Gel Treatments and Polymer Floods.

Some organizations have not made a distinction between gel treatments and traditional polymer floods.^{10,11} For political and taxation purposes, both technologies were often lumped under the term, "polymer-augmented waterflood." When sorting through the literature, we needed to decide in which category a given project belonged. To explain why this distinction was necessary, we point out that a gel treatment should have a very different objective from that for a traditional polymer flood. Certainly, both processes are ultimately intended to improve reservoir sweep efficiency; however, in a traditional polymer flood, we want the injected polymer solution to penetrate as far as possible into the zones that were swept poorly before the polymer flood (e.g., the less-permeable zones). In contrast, in a gel treatment, we want gelant penetration to be maximized in the high-permeability channels and minimized in the less-permeable, oil-productive zones. Gel that forms in the oil-productive zones acts to reduce sweep efficiency.¹²⁻¹⁴

In examining the literature, the distinction between gel treatments and polymer floods was usually made easily because most gel treatments used a crosslinker and small gelant volumes. In contrast, most polymer floods involved relatively large banks of uncrosslinked polymer solutions. However, in some cases, the distinction was less obvious. In particular, several projects involved injection of (1) a relatively small volume of a cationic polyacrylamide solution, (2) small volumes of an aluminum citrate solution, and (3) relatively large volumes of an anionic polyacrylamide solution.^{15,16} In an earlier survey,¹ these projects were classified as gel projects because a crosslinker was used. However, in the present survey, we classified them as polymer floods because of (1) the large size of the anionic polymer banks compared with the other chemical banks, and (2) the approach taken during the design and reporting of these projects.^{15,16}

Gel Treatments in Injection Wells. The results of our survey of injection-well gel projects are summarized in Table 1. This table lists median, minimum and maximum values for many properties of interest. For each property, Table 1 also lists the number of data points that were obtained for analysis; at least 40 data points were available for each property listed. Detailed distributions for each property are provided in Figs. 1 through 10 of Ref. 9. These figures also compare characteristics of gel projects with those of polymer floods.

Table 1 reveals that injection-well gel treatments have been applied over a remarkably wide range of conditions. Average reservoir permeabilities ranged from 4.1 to 5,000 md;

reservoir temperatures ranged from 18°C to 116°C; oil/water viscosity ratios ranged from 0.65 to 280; % original oil in place (OOIP) present at project startup ranged from 27.4 to 98.9; and the producing water/oil ratio (WOR) at project startup ranged from 0.1 to 160.

In an effort to establish where these gel treatments were most effective, we correlated various parameters for the different projects. One would expect the best candidate reservoirs for gel treatments to have a low recovery efficiency and a high WOR value. Our analysis of injection-well gel treatments indicates that most WOR values (at project startup) were in the range from 3 to 100. The median value was 11.5. Apparently, a high water cut in offset production wells was the primary criterion for candidate selection. Surprisingly, no correlation was evident with the %OOIP produced before the project. In one case where the WOR was 10.8 at project startup, 72.6% OOIP had been produced before the gel project was implemented. Evidently, the mobile oil saturation was often not given much consideration during candidate selection.

For the gel projects, WOR is plotted versus the oil/water viscosity ratio in Fig. 1. Other factors being equal, water channeling (i.e., the WOR) is expected to increase in severity with increased mobility ratio (and oil/water viscosity ratio). Thus, a greater number of gel treatments might have been expected in reservoirs with high oil/water viscosity ratios. Fig. 1 does not support this expectation.

The median oil/water viscosity ratio for the gel treatments was 6.6. If we assume that the ratio of endpoint permeabilities, k_o/k_w , was between 5 and 10, then the median endpoint mobility ratio, $(k_w/\mu_w)/(k_o/\mu_o)$, was approximately equal to one. Thus, roughly 50% of the reservoirs had a favorable mobility ratio during waterflood operations, suggesting that in at least half of the cases, channeling was caused more by reservoir heterogeneity (e.g., fractures and high-permeability streaks) than by an adverse mobility ratio.

Of the parameters that were examined during this study, only two appeared to correlate. As shown in Fig. 2, the projected incremental oil recovery (IOR, in bbl) increased with increased quantity of polymer injected (in lbs). The median value for the projected IOR was 2.4 bbl oil/lb of polymer. However, Fig. 2 shows substantial scatter in the correlation. This scatter was not reduced by grouping the projects by lithology.

The projected IOR (in % OOIP) is plotted versus % OOIP produced before project startup in Fig. 3. The median projected IOR was 1.3% OOIP. Contrary to expectations, no correlation was evident between projected IOR and the oil produced before project startup. We must note that the IOR values reported here were usually projections. In most cases,

these projections were published near the start of the project. Often, the method used to estimate incremental oil provided **only a crude guess**. For example, a fixed %OOIP was sometimes chosen as an incremental oil value, regardless of variations in reservoir conditions. Other operators chose a fixed number of barrels of incremental oil per pound of polymer injected. In other cases, the projections were based on simulation of a polymer flood that was radically different than the gel treatment. Thus, the validity of many projections is questionable. Unfortunately, oil-recovery values were usually not provided after the projects were completed. Thus, **the projections shown here should be viewed with caution**. In view of the sporadic success rate for gel treatments, questions about the validity of many IOR projections, and the sketchy reporting of the field data, published field data by itself is insufficient to establish guidelines for where or how to best apply gel treatments in injection wells.

Gel Treatments in Production Wells. Results of our literature survey of field activity for polymer and gel treatments in production wells are summarized in **Table 2**. Our survey examined **274** individual well treatments that were reported during the 1970s and 1980s. There is a key difference between the results from our surveys of applications in production wells and injection wells. While results from the injection-well treatments were usually projections that were made at the start of the project, the production-well results were generally reported after the project was completed. Thus, IOR values for the latter may be more credible.

Table 2 indicates that at least **54%** of the production-well treatments were applied in (1) dolomite formations, (2) formations that were known to be fractured, and (3) reservoirs that were produced by a bottom-water drive. The percentages of projects with these characteristics may actually be greater since these properties were not specified in many cases. Interestingly, half of the reported applications occurred in either the Arbuckle formation or the Ellenberger formation. We note that more than **75%** of the production-well treatments in our study were reported by gel vendors. Since vendors tend to focus on successful cases, one could argue that the literature indicates that the most successful production-well applications have occurred in naturally fractured carbonate formations that are produced by bottom-water drive.

We used cumulative frequency plots to compare WOR values and oil productivities before and after the treatments. For the y-axis in **Figs. 4 and 5**, cumulative frequency is the percentage of the data points associated with a property value less than or equal to that indicated on the x-axis. For example, **Fig. 4** shows that 60% of the cases had WOR values that were less than or equal to 100 before treatment, while the other 40% had WOR values that were greater than 100 before treatment.

The distribution of WOR values at various times before and after treatment are shown in **Fig. 4**. (**Figs. 4 and 5** include results from both polymer and gel treatments.) **Fig. 4** shows that, at most cumulative frequency values, the WOR values were reduced significantly within one month after treatment; the median WOR value was reduced from 82 to 7. However, WOR values gradually increased as time elapsed. After one to two years, the median WOR had risen to 20.

Fig. 5 is a cumulative frequency plot of oil productivity ratios at various times after treatment. The oil productivity ratio is defined as the oil productivity after treatment divided by the oil productivity before treatment. Thus, an oil productivity ratio below one indicates that the oil productivity was damaged by the treatment. **Fig. 5** shows that immediately after the polymer and gel treatments, the median value of oil productivity was increased by a factor of three. However, on average, this increase was lost after one to two years. The reader should note that **Figs. 4 and 5** apply to literature reports, which tend to focus on successes. These figures probably do not reflect most of the industry's failures.

SURVEY OF VENDORS AND MAJOR OIL COMPANIES

After recognizing that the petroleum literature did not provide sufficient information to establish guidelines for where or how to best apply gel treatments, we surveyed seven gel vendors and experts from eight major oil companies concerning the selection of candidate wells and the implementation of gel treatments. These surveys focused on the period from 1990 until 1993.

Our surveys revealed that, since 1990, about 80% of the gel treatments were applied in production wells. In contrast, **between 1980 and 1986**, applications in injection wells were much more common than those in production wells. The shift in preference can be attributed to two factors. First, after 1985, low oil prices eliminated tax incentives that favored applications in injectors. Second, the effectiveness of gel treatments in production wells usually can be judged more quickly and definitively than that in injection wells. In the current economic environment, aspirations for a short payout period often favor producer applications.

For gel treatments in production wells, **Fig. 6** provides a breakdown of the applications according to the probable source of water. **Fig. 6** shows that the mix of applications in bottom-water-drive reservoirs versus waterfloods varied considerably for both operators and vendors. One company had 100% bottom-water-drive wells; a second company had 90% of the treatments in waterflood producers; and the water source was unknown for 90% of a third company's applications.

Success Rates. Fig. 7 shows economic success rates given by operators and vendors for their production-well applications. Success rates claimed by vendors were usually quite high, regardless of the water source. For the operators, applications in waterflood producers appeared to have the highest success rates (60% to 100%). When the source of the water was unknown, success rates reported by the operators were low (0% to 30%). The widest variation in success rates (10% to 100%) occurred for applications in bottom-water-drive producers. For gel applications in injection wells, economic success rates given by operators varied from 35% to 85%.⁹ Interestingly, we note that the average success rates derived from our surveys of operators and vendors were significantly greater than the values quoted in the October 1992 issue of *Petroleum Engineer International*.⁸ That publication indicated a 43% economic success rate for gel treatments.

Effect of Lithology. Fig. 8 shows the frequency of recent gel applications in carbonate formations. (The frequency of applications in sandstones can be determined from Fig. 8 by difference between 100% and the value for a given data point.) In both production and injection wells, the frequency of application in carbonates versus sandstones varied greatly with the operator or vendor. Overall, recent treatments were applied more often in carbonates than in sandstones. This finding is consistent with our literature survey of gel treatments in production wells. However, our literature survey of gel treatments in injection wells during the 1980s indicated that applications in sandstone reservoirs outnumbered those in carbonate reservoirs by a factor of 2.6 (see Table 1).

We asked the vendors and operators if lithology has an important impact on the probability of success for gel treatments. Six of the vendors and five of the operators responded that lithology can have an important effect. Of those, most felt that treatment success was highest in carbonate reservoirs, primarily because of a greater probability that fractures were present. Also, most respondents felt that the specific nature of the formation (e.g., presence of fractures) was more important than the mineralogy of the rock.

With only two exceptions, all respondents thought that most of the wells that they treated were fractured or experienced a formation parting problem (Fig. 9). The exceptions included one operator who felt that only 10% of their production wells were fractured and one vendor who thought that only 30% of their injection wells were fractured.

Oil Viscosity. Half of the vendors and one-third of the operators surveyed felt that oil viscosity had an important effect on treatment performance.⁹ All of those people thought that greater success occurred in reservoirs with moderately viscous oils.

Gels as a Substitute for Cement. Not all gel applications were directed at in-depth channeling problems. For several companies, up to one-third of their applications used gels as a substitute for cement in fixing casing leaks or flow behind pipe.⁹ The main advantage of gels over cements is a superior ability of gelants to penetrate into constricted spaces, such as narrow channels behind pipe, small casing leaks, and fractures. Also, because gelants can penetrate into porous rock, gels can sometimes form a better pipe-formation seal than can be obtained using cement.^{17,18}

More detailed results from our surveys can be found in Chapters 2 through 5 of Ref. 9.

CANDIDATE SELECTION

For the oil companies that we surveyed, field engineers played the primary role in identifying candidates for treatment. Thus, field engineers have the greatest need to know the proper criteria for candidate selection. After extensive discussions with experts from the oil and service companies, we developed the criteria listed in Tables 3 and 4 for candidate selection of injection and production wells, respectively.

Mobile-Oil Target. For both injection and production wells, the first criterion indicates that a sufficient target of mobile oil must be present, and realistic calculations should indicate that the oil can be recovered economically. In Table 3, several qualifications were added to clarify what is meant by "low sweep efficiency." We felt that this clarification was necessary because different operators interpret this phrase in radically different ways. Cases exist where gel treatments were implemented even though more than 50 percent of the original oil in place had been recovered before the treatment (see Fig. 3). Point c in the first criterion is particularly important for applications in gray areas. One criticism of this point might be that, often, insufficient manpower or reservoir description is available to adequately predict the benefits of a gel treatment. If that is the case and if the second or third criterion in Table 3 cannot be met, then we feel that a gel treatment in an injection well is unlikely to be successful. Recovery calculations were also felt to be very important in the selection of production-well candidates (Table 4).

Interwell Tracer Studies. An essential element of improving the success rates for gel treatments is adequate identification of the source and nature of the channeling problem. Determination of the importance of fractures as channels is a first priority. For applications in injection wells or waterflood production wells, interwell tracer studies can be the most effective tool in identifying very severe channeling between injector-producer pairs.^{4,5} Very rapid tracer transit times (less

than one week) probably indicate that the channel is a fracture or a formation part. In addition to diagnosing the severity of the channeling problem, tracer studies can be very useful in designing the volume of gelant to be injected and assessing the ultimate effectiveness of the treatment.⁹

Fig. 10 shows that the use of tracers varies widely, depending on the operator or vendor. Although tracer studies were performed for less than half of the injection-well treatments, most experts felt that tracers should be used before implementing at least 80% of the applications.⁹ Increased use of small volumes of relatively inexpensive tracers may be one of the best ways to improve the success rate for water-shutoff treatments in secondary or tertiary recovery operations.

Injectivities and Productivities. Tables 3 and 4 indicate that high well injectivities or productivities are important for candidate selection. These requirements recognize that a gel treatment will generally reduce the flow capacity of a well. For a given pressure limit, the injection or production rates will be lower after a treatment than before a treatment. By having excess injection or production capacity before the treatment, the operator will be more likely to tolerate the reductions in flow capacity that result from a gel treatment.

Simple injectivity or productivity calculations can aid in establishing the nature of a channeling problem. The Darcy equation for radial flow (Eq. 1) can be used for this purpose.

$$\frac{q}{A_p} = \frac{dh}{141.2 \mu \ln(r_e/r_w)} \dots \dots \dots (1)$$

If the injectivity (or productivity) calculated by the right side of Eq. 1 is substantially less than the actual $q/\Delta p$, then a fracture or formation part is probably present. The parameters in Eq. 1 are generally readily accessible. Estimates of net pay and average permeability can usually be obtained from logs, core data, or pressure transient analyses. Static fluid levels and flowing well pressures are also commonly available so that the pressure drop, A_p , can be determined between the wellbore and the formation. If the well is an injector or a producer with a high water cut, μ is the viscosity of water. The $\ln(r_e/r_w)$ term is approximately equal to 6.

Unfractured Wells. For unfractured injection wells, Table 3 lists three important conditions that must be present before candidate selection: (1) poor injection profiles must correlate from well to well, (2) effective barriers to crossflow must exist, and (3) gels can be placed in the offending channel without damaging oil zones. To prevent damage to oil-productivity, zones usually must be mechanically isolated during gelant placement in unfractured injection wells.¹² This requirement also applies in unfractured production wells.¹³ If

zones are not isolated during gelant placement in unfractured wells, low-permeability zones can be seriously damaged even in extremely heterogeneous reservoirs (e.g., Dykstra-Parsons coefficient of 0.9).¹⁹

Mechanical Condition of the Well. Most vendors and operators felt that the candidate well should be in good mechanical condition for applications in injection wells.⁹ They felt that this requirement often was less critical for production-well applications.

Other Diagnostic Tools. A number of other diagnostic tools are available to characterize the nature of the excess water production, including flow profiles, pressure transient analyses, and various logs (e.g., temperature, noise, C/O, etc.). Under the right circumstances, these tools can be very valuable. However, they have often been used improperly or their output has been misinterpreted. This has been particularly true for flow profiles and permeability-variation data.^{19,20}

TREATMENT DESIGN

Gelant Volumes. In recent years, a few treatments have involved large gelant volumes (more than 10,000 bbl/well).⁵ However, our surveys revealed that the vast majority of treatments have been very small—less than 1000 bbl/well. The sizing of gelant treatments varies somewhat from vendor to vendor. For some vendors, the gelant volume is initially planned as 1/2 to 1 day's injection or production volume. Other vendors plan for a certain number of barrels of gelant per foot of net pay. Still others plan to inject gelant to reach a certain radius from the wellbore. The latter plan seems ironic since most treated wells are thought to be fractured, where the flow geometry is described better as linear rather than radial.⁹ Most vendors plan an upper limit for their injection volumes, regardless of formation thickness. The reason for doing this is strictly economic. Vendors fear that above a certain base cost per well, the operator will not accept their plan. Ironically, recent field results suggest that larger treatments can be economically superior to small-volume treatments.⁷

Hall plots (or variations of Hall plots) are commonly used to determine when gelant injection should be terminated during actual field operations.⁹ These plots can provide a useful indication of general injectivity changes, but they do not indicate the selectivity of gelants in entering one zone in preference to another (see Chapter 6 of Ref. 9).

Obviously, improvements are needed in the methods used for sizing gel treatments. The method of sizing should be tailored to the type of channeling problem encountered. Five different types of channeling problems include (1) individual fractures,

(2) fracture networks, (3) a high-permeability rock stratum that is separated from oil-productive zones by impermeable barriers, (4) a high-permeability rock stratum that is in direct pressure communication with oil-productive zones (i.e., fluids can freely crossflow between strata), and (5) flow behind pipe occurring because of inadequate cement fill and bonding.

Individual Fractures. When the channel is a fracture in a waterflooded reservoir, many of the respondents felt that interwell tracer studies could provide a useful basis to determine the volume of gelant injected. Depending on the company, the suggested volume of gelant varied from 50% to 100% of the injection volume associated with tracer breakthrough (i.e., tracer transit between injector and producer).⁹ Of course, the objective of this strategy is to fill most of the fracture with gel. Depending on the viscosity of the gelant and the degree of gelation, this strategy may not adequately account for gelant leakoff from the fractures.⁹

Fracture Networks. When the channel is a fracture network in a waterflooded reservoir, one operator felt the volume of gelant injected should be many times the volume associated with tracer breakthrough. In partial justification of this suggestion, injection-well applications have been found where the gelant was not detected at the production well even though the injected gelant volume was ten times greater than the volume associated with tracer breakthrough.⁹

The explanation for the delayed arrival of the gelant may be tied to the viscosity of the gelant compared with that of the tracer solution. Viscous injectants tend to penetrate farther into less-permeable pathways (either porous rock or alternate fracture pathways) than do low-viscosity injectants.¹²⁻¹⁴ Since the gelant is usually much more viscous than the aqueous tracer solution, the gelant requires much longer to propagate a given distance through a formation. Of course, chemical retention and filtration effects can also retard the movement of polymers, crosslinkers and gels. However, these phenomena are likely to be less important during propagation through fractures than through a porous rock.

Strata Separated by Barriers. When the channel is a high-permeability stratum that is separated from oil-productive zones by impermeable barriers, then one need inject only enough gelant to plug the high-permeability channel near the wellbore. Many companies recommended that the gelant should penetrate a certain minimum radial distance from the wellbore. This distance ranged from 10 to 100 feet, depending on the operator. Some companies specified that the gelant volume should be dictated by the injectivity loss in the channel. This method seems reasonable so long as the injectivity loss is applied specifically to the offending channel(s) and not to the overall injectivity index for all zones open to the well.^{9,12,19}

Strata with Crossflow. When the channel is a high-permeability stratum that is in direct pressure communication with oil-productive zones, then substantial differences of opinion exist about treatment design. One view is that this situation is not treatable by any gel technology that currently exists. A traditional polymer flood should be greatly preferred over gelant injection for treating this situation.^{14,21-23}

A second view is that, under the right circumstances, this condition could be successfully treated using a low-viscosity gelant that penetrates a substantial distance into the channel.^{14,24} For this process, very large volumes of gelant must be injected, and some means must be available to substantially delay gelation. Although there are many challenges to the successful implementation of this technology, it has considerable merit and is being field tested.

A third viewpoint is that reservoirs with extensive crossflow could be treated by injecting a gelant that acts like an enhanced polymer solution; that is, a crosslinker simply increases the viscosity of the polymer solution, and the resulting "gel" propagates through the formation like a polymer solution. Such a system would provide a truly dramatic advance in improving the cost-effectiveness of traditional polymer flooding. Unfortunately, all available evidence indicates that this type of gelant system does not yet exist. (Of course, using crosslinked polymers to plug severe channels before a traditional polymer flood is a worthwhile idea.^{2,25})

A fourth view is that conventional gel treatments can be effective in unfractured reservoirs with extensive crossflow if the channel is a very high-permeability, small-volume pathway that allows very rapid tracer transit between wells (e.g., less than one week). The challenge for this view is to identify a real geologic structure or phenomenon that could be used to quantitatively justify (1) how the high-permeability, small-volume pathway was created and (2) why tracer propagation is so rapid. At present, the only structures that fit these requirements (as we see it) are fractures, formation parts, or possibly, very long, narrow viscous fingers (which require that the oil be very viscous).⁹

Flow Behind Pipe. When the channel occurs from flow behind pipe, one operator suggested that the gelant volume be roughly three times greater than that for a cement squeeze.⁹ Compared with a cement squeeze, a larger volume is needed for gel treatments because gelants penetrate into the porous rock whereas cement (including ultrafine cement) does not.

Improvements are needed in the sizing and placement of gel treatments for all of the above applications.

CONCLUSIONS

1. Our review of the petroleum literature demonstrated that gel treatments have been applied over a remarkably wide range of conditions. Unfortunately, the success rates for these projects have been very sporadic. Our analysis indicates that the producing water/oil ratio was usually the only criterion used to select candidates for gel treatments.
2. Proposed criteria for selection of candidates for gel treatments are listed in Tables 3 and 4. To improve the success rate for future gel applications, the source and nature of the water production problem must be adequately identified. Results from interwell tracer studies and injectivity and productivity calculations can be especially useful in this diagnosis. Recovery calculations should indicate that considerable mobile oil remains that could be recovered more cost-effectively if a blocking agent could be realistically placed in the proper location.
3. Improvements are needed in the methods used for sizing gel treatments. The method of sizing should be tailored to the type of channeling problem encountered. Five different types of channeling problems were discussed.

NOMENCLATURE

- h = formation thickness, ft [m]
 k = permeability, md [μm^2]
 k_o = permeability to oil, md [μm^2]
 k_w = permeability to water, md [μm^2]
 Δp = difference between flowing and static bottomhole pressures, psi [Pa]
 q = volumetric injection or production rate, bbl/D [m^3/s]
 r_e = external radius, ft [m]
 r_w = wellbore radius, ft [m]
 μ_o = oil viscosity, cp [mPa-s]
 μ_w = water viscosity, cp [mPa-s]

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Table 1. Summary of Injection-Well Gel Projects Reported in the 1980s (114 Projects in Database)

Property	Median value	Minimum value	Maximum value	Number of data points
Permeability, md	100	4.1	5,000	111
Temperature, °C	43	18	116	95
Oil/water relative viscosity at reservoir temperature	6.6	0.65	280	91
%OOIP present at project startup	75.0	27.4	98.9	60
Water/oil ratio at project startup	11.5	0.1	160	40
Polymer concentration, ppm	2500	300	70,000	50
Polymer injected, lbs/ac-ft	1.6	0.006	35	50
Projected IOR, %OOIP	1.3	0	18	62
Projected IOR, bbl/lb polymer	2.4	0	560	57
Projected IOR, bbl/ac-ft	5.9	0	169	66
Lithology, sandstone/carbonate	81/31 = 2.6			112
Polymer type, HPAM/xanthan	48/29 = 1.7			87 [†]

* Ten gel projects used materials other than HPAM or xanthan,

Table 2. Summary of Production-Well Polymer and Gel Treatments Reported in the 1970s and 1980s (274 Treatments in Database)

		No.	%			No.	%	
Formation	Arbuckle	105	38.3	Production mechanism	Bottom-water drive	160	58.4	
	Ellenberger	32	11.7		Other known	6	2.2	
	Other known	68	24.8		Not specified	108	39.4	
	Not specified	69	25.2	Treatment type	Gel (with crosslinker)	168	61.3	
Lithology	Dolomite	150	54.7		Polymer (HPAM without crosslinker)	106	38.7	
	Sandstone	59	21.5		Gel type	Chromium-HPAM	129	76.8
	Limestone	18	6.6			Glyoxal-CPAM	13	7.7
	Not specified	47	17.2	Aluminum-HPAM		6	3.6	
Fracture status	Fractured	149	54.4	Inorganic		5	3.0	
	Not fractured	9	3.3	Not specified	15	8.9		
	Not specified	116	42.3					

Table 3. Selection Criteria for Injection Wells

1. Reservoir and production data indicates low Sweep efficiency during waterflooding.
 - a. Water breakthrough **occurs** much earlier than expected (i.e., from standard calculations or simulations or from comparison with the **performance of other patterns in the field**).
 - b. **WOR values** at offset producers are much **higher than expected**.
 - c. **Recovery calculations** indicate that **considerable mobile oil remains that could be recovered more cost-effectively if a blocking agent could be realistically placed in the proper location**.
2. If barriers to **crossflow** do not exist, then interwell tracers must show very rapid transit times (probably **indicating that fractures** or formation parting cause the channeling problem).
3. In **unfractured wells**,
 - a. **Poor injection profiles must be correlatable from well to well**.
 - b. **Effective barriers to crossflow must exist (very low k_v/k_h , no flow behind pipe, no vertical fractures)**.
 - c. **Gel can be placed in the offending channel without damaging oil zones (e.g., using zone isolation)**.
4. **Reduced injectivity (caused by the gel) can be tolerated**.
5. The well to be treated is in good mechanical condition.

Table 4. Selection Criteria for Production Wells

1. Recovery calculations indicate that considerable mobile oil remains that could be recovered more cost-effectively if a blocking agent could be realistically placed in the proper location.
2. High WOR values are observed.
3. The source of the excess water production is identified (e.g., using profiles, logs, or tracers).
4. The candidate well exhibits high productivity.
5. The gelant can be placed without damaging oil zones (e.g., using zone isolation).

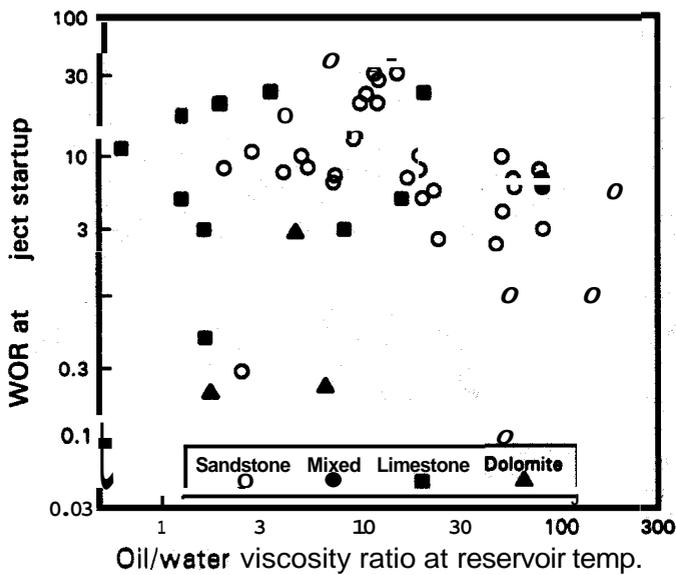


Fig. 1. WOR versus oil/water viscosity ratio for injection-well gel projects.

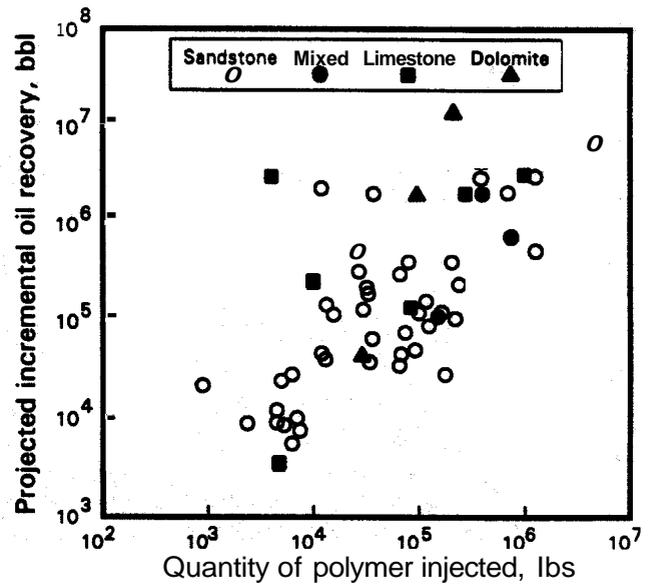


Fig. 2. Projected IOR versus lbs of polymer for injection-well gel projects.

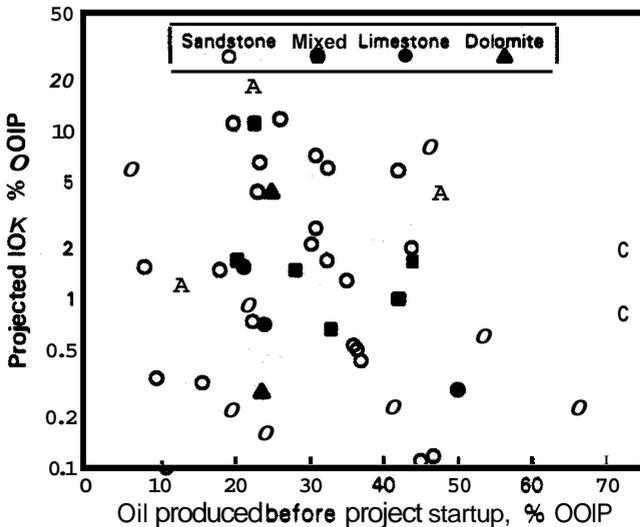


Fig. 3. Projected IOR versus % OOIP produced before startup for injection-well gel projects.

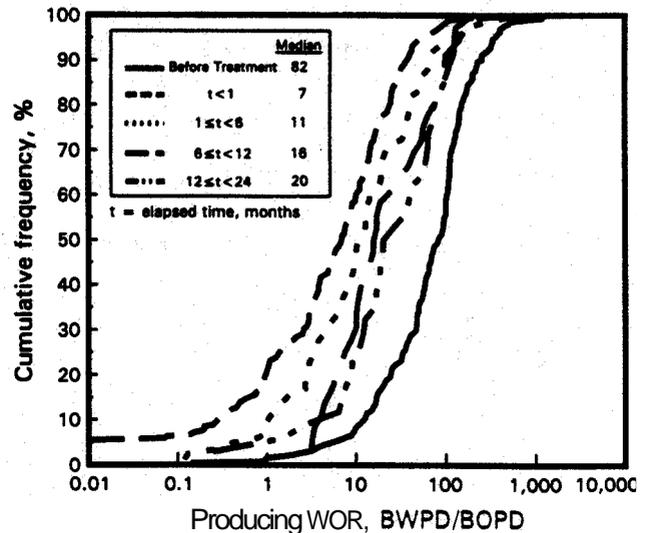


Fig. 4. Cumulative frequency plot of WOR before and after production-well treatments.

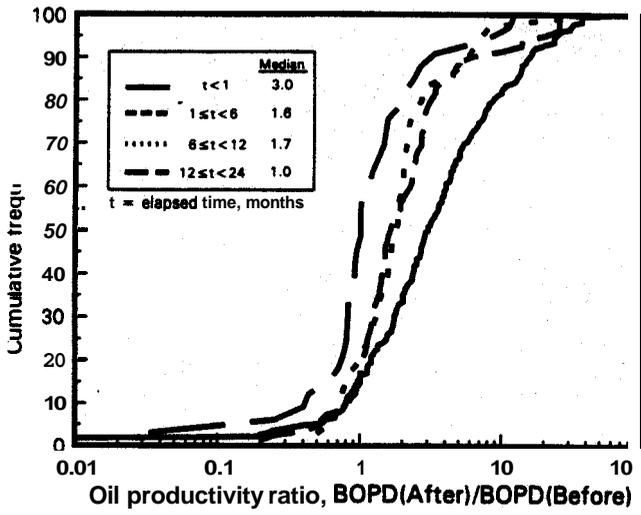


Fig. 5. Cumulative frequency plot of oil productivity ratios before and after production-well treatments.

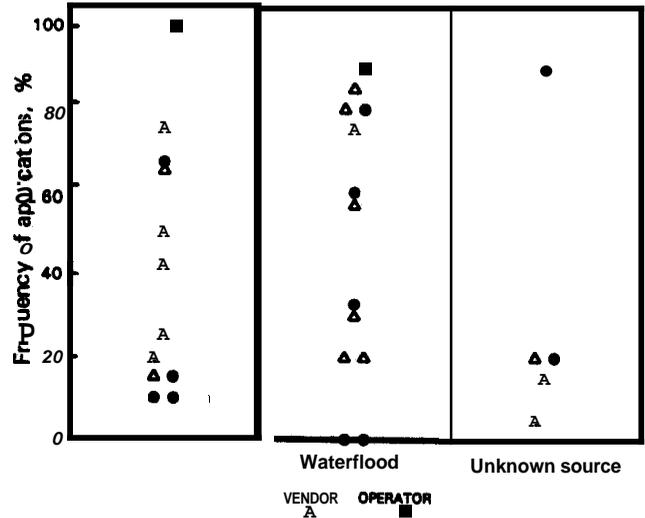


Fig. 6. Distribution of production-well applications.

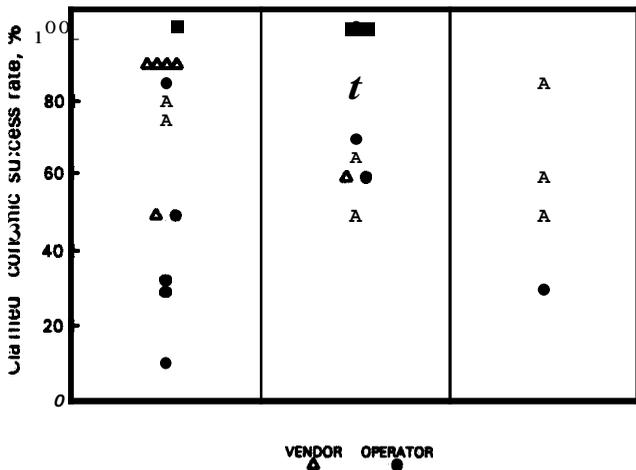


Fig. 7. Success rates for production-well applications.

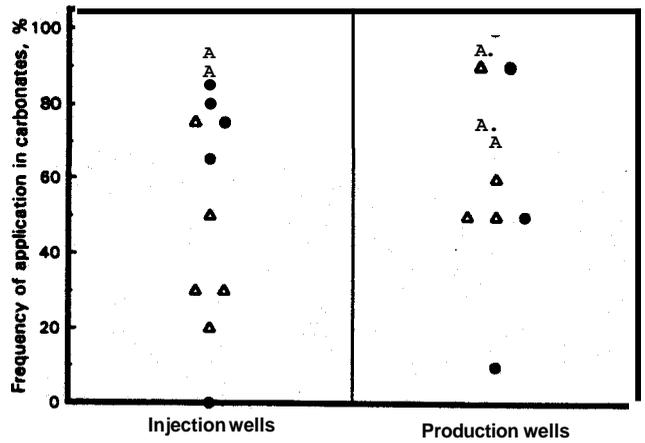


Fig. 8. Frequency of applications in carbonate formations.

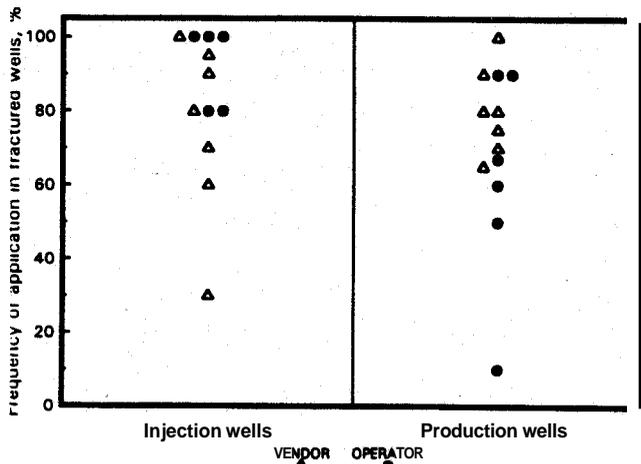


Fig. 9. Frequency of application in fractured wells.

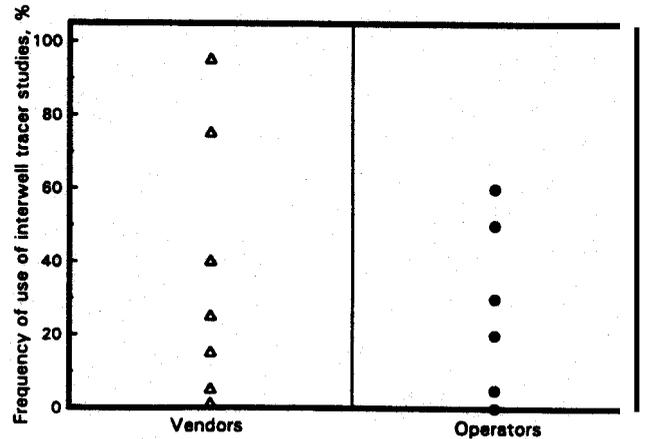


Fig. 10. Frequency of use of interwell tracer studies for diagnosing channeling in waterfloods.