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Sweep Improvement Options for the Daqing Oil Field

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Abstract

This paper investigates the potential of various approaches for improving sweep in parts of the Daqing Oil Field that have been EOR targets. Possibilities included (1) gel treatments that are directed at channeling through fractures, (2) colloidal dispersion gels, (3) reduced polymer degradation, (4) more viscous polymer solutions, and (5) foams and other methods. Our studies indicated that the polymer flood should have provided excellent sweep throughout the vast majority of the patterns under consideration. However, since ASP flooding is being considered to increase recovery efficiency from the Daqing Oil Field, mobility control and sweep improvement will be especially important and challenging during implementation of any future ASP process.

Fractures were present in a number of Daqing wells (both injectors and producers). Because the fractures were narrow far from the wellbore, severe channeling did not occur. On the contrary, fractures near the wellbore aided reservoir sweep. These near-wellbore fractures substantially increased the injectivity index during injection of polymer solutions and increased oil productivity index in the production wells. These observations may be valuable during implementation of future floods where very low-mobility chemical (i.e., ASP) banks must be injected to maintain mobility control.

Several modes of polymer degradation were considered, with mechanical (shear) degradation being of most concern. Appropriate use of near-wellbore fractures may effectively mitigate mechanical degradation, as well as improving injectivity.

Several new polymers show potential for cost-effective improvements at Daqing. Increased polymer concentration was also considered. A number of other approaches are (or have been) under investigation, including colloidal dispersion gels, foams, ASP foams, steam, microbes, and polymer solutions prepared with reduced salinity.

Introduction

Laboratory research began in the 1960s, investigating the potential of enhanced oil recovery (EOR) processes in the Daqing Oil Field. Use of polymer flooding was identified as a key method to improve areal and vertical sweep efficiency, as well as providing mobility control.¹ Consequently, the world's largest polymer flood was implemented at Daqing, beginning in 1996.^{2,3} By 2004, 22.7% of total production from the Daqing Oil Field was attributed to polymer flooding. Polymer flooding should boost the ultimate recovery for the field to over 50% original oil in place (OOIP)—10% OOIP more than from waterflooding.

Alkaline/surfactant/polymer flooding (ASP) has also experienced extensive laboratory testing in China. The ASP technique was gradually perfected for application at Daqing and has been pilot tested on a large scale.⁴⁻⁶ Results from two typical pilot tests in the south and north parts of the Daqing field revealed incremental oil recovery values as high as 20% OOIP. By the end of 2003, the Center Xinger pilot site showed a definitive increase in oil production and decrease in water cut. In the east area of this site (the largest portion included within the ASP pattern area), the predicted EOR was about 18% OOIP more than from waterflooding.

Although field tests of polymer and ASP flooding have been very successful at Daqing, concerns about sweep efficiency persist—particularly the possibility of channeling expensive chemical formulations through the reservoir. Therefore, the sweep efficiency at Daqing is receiving intense scrutiny, and possibilities for improvement are being considered. In this paper, we examine the nature of reservoir sweep in parts of the Daqing Oil Field that have been EOR targets. We investigate the potential of various approaches for improving sweep, including (1) gel treatments that are directed at channeling through fractures, (2) colloidal dispersion gels, (3) reduced polymer degradation, (4) more viscous polymer solutions, and (5) foams and other methods (e.g., thermal and microbial techniques). Our objective is to establish better options for improving sweep in the main producing zone in the future.

Sweep Efficiency in the Daqing Oil Field

Stratification. What is the nature of the sweep efficiency problem at Daqing? This study focused on the Eastern Berxi polymer flooding area of the Daqing field—specifically on 17 production wells and 8 injection wells. Layer PI, a principal target for EOR at Daqing, is composed of up to seven named “zones.” The gross pay for Layer PI varied between 18 and 33

meters. Net pay varied from 11 and 31 meters, averaging 18 meters. Within the net pay, some degree of vertical stratification existed. Figs. 1-3 illustrate this stratification for three wells. For the 25 wells, the Dykstra-Parsons coefficient of permeability variation ranged from 0.14 to 0.89, averaging 0.70. Fig. 1 illustrates the distribution for Production Well B2-4-P43. In this well, five strata were identified, with the top zone being the most permeable zone ($1.2 \mu\text{m}^2$). Three intermediate zones had about the same permeability, ranging from 0.4 to $0.5 \mu\text{m}^2$. A small zone at the bottom was the least permeable, with $0.232 \mu\text{m}^2$. For this well, most flow capacity and net pay existed in a single interval where crossflow could freely occur. This feature was shared by 32% of the wells examined.

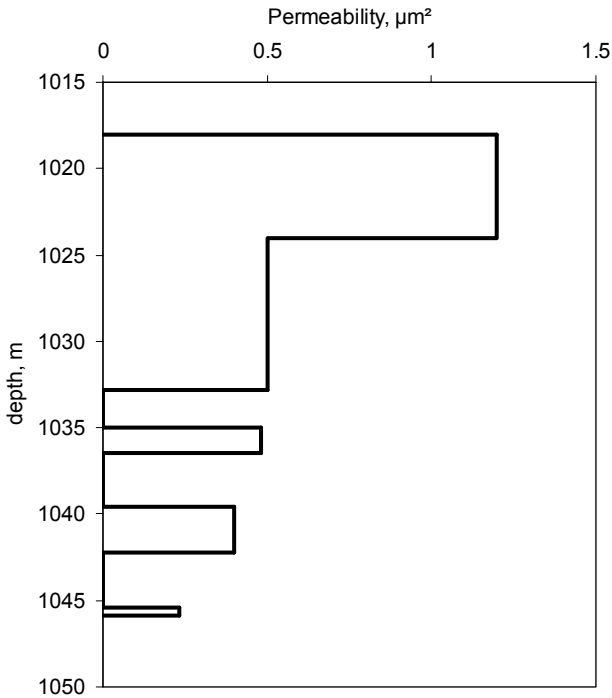


Fig. 1—Permeability distribution Producer B2-4-P43.

Fig. 2 illustrates the distribution for Production Well B2-D6-P45. Four strata were identified, with the top and bottom zones having similar permeabilities (0.49 - $0.5 \mu\text{m}^2$). A 0.316 - μm^2 zone at $1,017$ m probably had direct flow contact (crossflow) with the bottom zone. A small 0.142 - μm^2 zone at $1,010$ m appeared distinct from the other zones. For this well, most of the net pay existed in zones that had about the same permeability. This feature was exhibited by 36% of the wells examined.

Fig. 3 illustrates the distribution for Production Well B2-D6-P47, where seven strata were identified. The interval from 988 to $1,001$ m should be considered as a single flow unit, with an average permeability around $0.5 \mu\text{m}^2$. A 1.2 - μm^2 zone existed at $1,017$ m. Between $1,005$ and $1,013$ m, three small zones were present, with permeabilities ranging from 0.147 to $0.21 \mu\text{m}^2$. Thus, for this well, the net pay existed in distinct zones with noticeably different permeabilities. This characterization was shared by 28% of the wells examined.

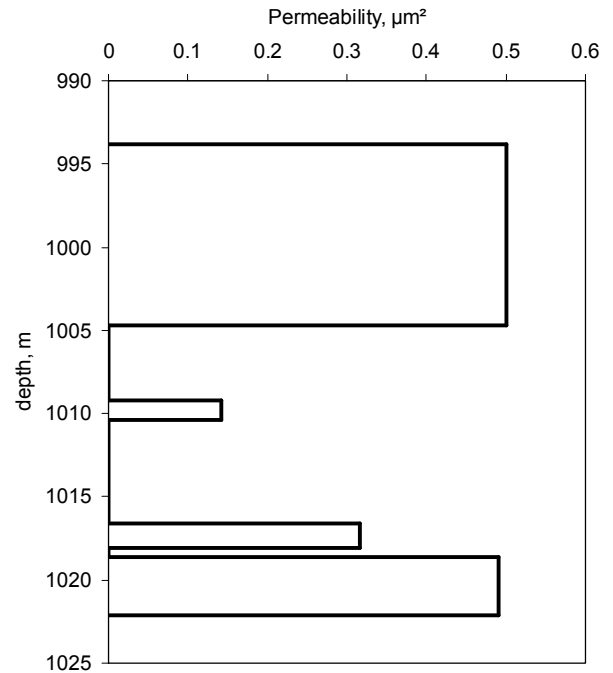


Fig. 2—Permeability distribution Producer B2-D6-P45.

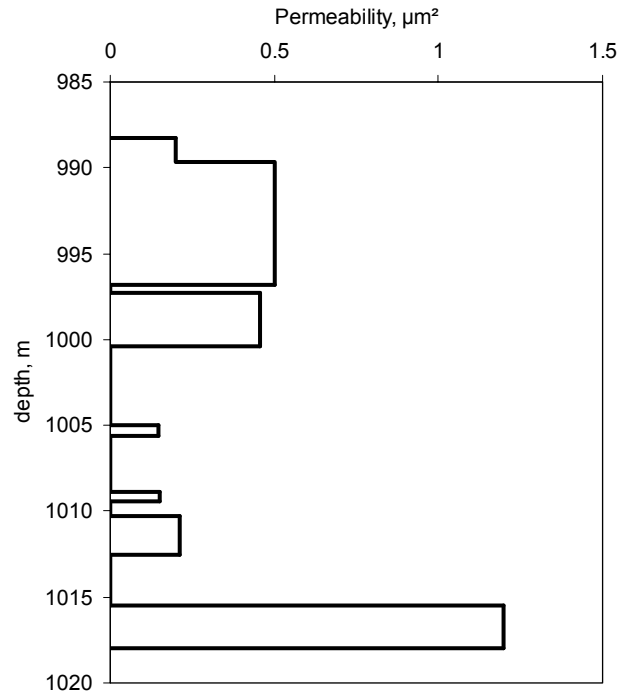


Fig. 3—Permeability distribution Producer B2-D6-P47.

Mobility Ratios. At Daqing, the endpoint relative permeabilities were $k_{rw} \sim 0.5$ and $k_{ro} \sim 0.8$, oil viscosity was 9 mPa-s, and water viscosity was 0.6 mPa-s. Thus, during waterflooding, the endpoint mobility ratio was 9.4 . With this unfavorable mobility ratio, viscous fingers can form that lead

to severe channeling, especially when zones with different permeability are present.

By injecting a viscous polymer solution, the mobility ratio was increased to the point of making it favorable. The viscosity of the injected polymer solution was typically 35 to 40 mPa-s. If polymer degradation was not significant, this level of viscosity decreased the mobility ratio from 9.4 to about 0.25. When fluids can freely crossflow between strata, the rate of movement of a polymer front is independent of permeability, so long as the reciprocal of the mobility ratio is greater than the permeability contrast between the strata.⁷ The two upper strata in Fig. 1 had permeabilities of 0.5 and 1.2 μm^2 (i.e., a permeability contrast of 2.4 and combined average permeability of 0.783 μm^2) and were subject to unrestricted crossflow. Thus, during polymer flow where the reciprocal mobility ratio was 4 (i.e., 1/0.25), the upper strata in Well B2-4-P43 should have been swept quite efficiently.

The bottom three strata in Fig. 1 had permeabilities of 0.482, 0.398, and 0.232 μm^2 , respectively. The relative rates of propagation for the polymer fronts in each stratum can be estimated using the methods in Refs. 7, 8, and 9. Given the permeabilities and the above mobility ratio, the relative rates of propagation of the polymer fronts for radial flow in the five zones would be 1, 1, 0.79, 0.72, and 0.56, respectively. Some evidence exists that the polymer may experience up to 50% loss of viscosity during injection. If the reciprocal mobility ratio was 2 instead of 4, the relative rates of propagation of the polymer fronts in the five zones were 1, 1, 0.78, 0.71, and 0.54, respectively.

For the above circumstances, sweep efficiency during the polymer flood should be quite good, with the possible exception of the very small 0.232- μm^2 bottom zone. Similar calculations can be made for the wells illustrated in Figs. 2 and 3. These calculations reveal that the polymer flood should have provided excellent sweep in all but the small zone at 1,010 m for Well B2-D6-P45 (Fig. 2) and the small zones from 1,005 to 1,013 m in Well B2-D6-P47 (Fig. 3). More generally, these calculations indicated that the polymer flood should have provided excellent sweep throughout the vast majority of the patterns associated with the 25 wells under consideration. Thus, if sweep was truly inadequate during the polymer flood, a reason for this inadequacy must be identified.

Mobility Control during ASP Flooding

ASP flooding is being considered to increase recovery efficiency from the Daqing Oil Field. Mobility control and sweep improvement will be especially important during implementation of the ASP process.

Mobility Control Requirements for ASP Flooding after Polymer Flooding. During a chemical flood (e.g., an ASP flood), mobility control means each successive fluid bank injected must be less mobile than the bank ahead of it. Without mobility control, expensive chemical banks experience significant channeling (via viscous fingers) even in homogeneous reservoirs. In heterogeneous reservoirs, channeling is accentuated with unfavorable mobility ratios.

If an ASP flood is the first EOR method applied in a reservoir, the ASP bank should be less mobile (more viscous) than the oil/water bank that is being displaced. Because an

ASP formulation decreases the residual oil saturation, effective permeability to the aqueous phase (i.e., the ASP formulation) can be much greater than that in a preceding waterflood. Consequently, the level of viscosity enhancement (mobility reduction) needed to provide mobility control is significantly greater than that if no reduction in S_{or} occurred.

For some areas of the Daqing Oil Field, ASP floods may be applied in patterns that were previously polymer flooded. Since the preceding polymer bank was quite viscous (20-40 mPa-s), the ASP bank must be even more viscous to maintain mobility control.

Higher Salinity of ASP Reduces Viscosity. Compounding this mobility problem, alkaline agents significantly increase the ionic strength of ASP formulations. The viscosity of a given concentration of anionic polymer (e.g., HPAM) is much lower in saline solutions (e.g., an ASP formulation) than in fresh water (e.g., used during the Daqing polymer floods).²⁻⁶ Thus, the concentrations and expense for polymer may be unusually high when applying ASP flooding after a polymer flood.

Figs. 4 and 5 show viscosity versus polymer concentration for polymers with medium and ultra-high molecular weights. As expected, viscosity increased with the increased polymer concentration, and was significantly lower with 1.4%-1.5% alkali than without alkali.

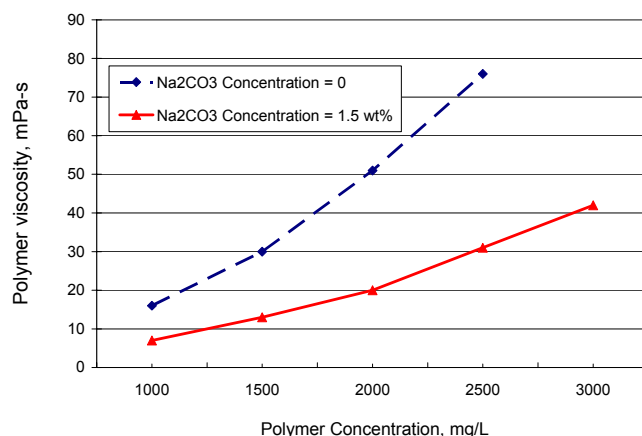


Fig. 4—Viscosity versus concentration of medium molecular weight polymer (LIANHUA-1500).

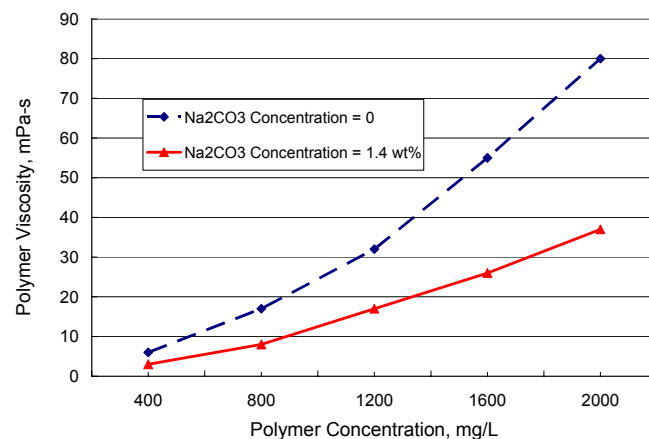


Fig. 5—Viscosity versus concentration of ultra-high molecular weight polymer (HENGJU).

Polymer Stability in the Presence of Alkali. When HPAM solutions are exposed either to high temperatures or high pH values, the polymer's amide groups can hydrolyze.^{10,11} However, the carbon-carbon backbone of the polymer is quite stable, as long as oxygen and free radicals are absent. Fig. 6 shows the stability of an ASP solution when the alkali concentration is 1.2%. The curve demonstrates that the ASP viscosity can be kept stable for at least 3 months when the polymer concentration is 1,200 mg/L.

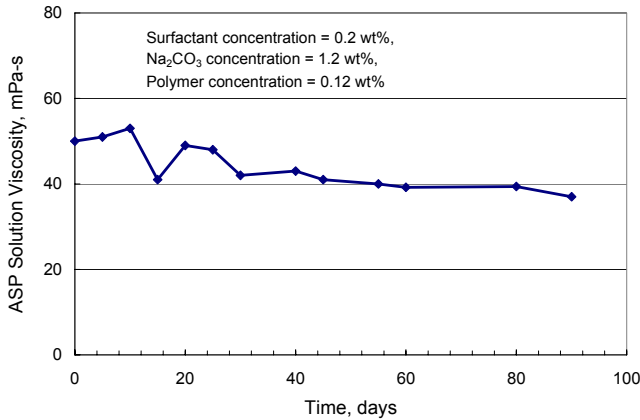


Fig. 6—Stability of ASP solution viscosity.

Reduced Injectivity for Viscous Solutions. ASP flooding displaces residual oil and increases the effective permeability, especially near injection wells. This effect enhances injectivity index. However, this beneficial effect is countered by the increased viscosity, reduced mobility and/or any permeability reduction associated with polymer in the ASP formulation.⁶

Figs. 7 and 8 show the predicted variation of injection pressures (based on the numerical simulation and the real data from the pilot site) before versus after ASP flooding in the First North-Fault from the West pilot test. Injection pressures increased gradually during injection of ASP solution. After 0.23 pore volumes (PV) of ASP, the average injection pressure increased from 9.18 MPa (during water drive) to 12.47 MPa—an increase of 3.29 MPa. Here, the injection rate was 0.206 PV/year, and the ASP injection viscosity was 37 mPa-s. Consequently, the injection ability and flow pressure decreased, but the injection pressure was still 1.03 MPa below the formation fracture pressure. At the peak predicted injection pressure, the water injectivity index for ASP was 13.9% less than during water injection. Even so, this loss of injectivity was less than that observed during polymer flooding, see Tables 1 and 2.

Table 1—Variation of Injection Pressure

Method	Well distance (m)	Injection intensity (m ³ /d-m)	Injection pressure (MPa)		Pressure increase (MPa)
			water drive	chemical flood	
ASP	250	20.5	9.18	12.47	3.29
Polymer	250	17.3	5.5	12.3	6.8

Table 2—Variation of Water Injectivity Index

Method	Well distance (m)	Injection intensity (m ³ /d-m)	Water injectivity index (m ³ /d-m-MPa)		Pressure increase (MPa)
			water drive	chemical flood	
ASP	250	20.5	3.51	3.02	3.29
Polymer	250	17.3	2.75	2.08	6.8

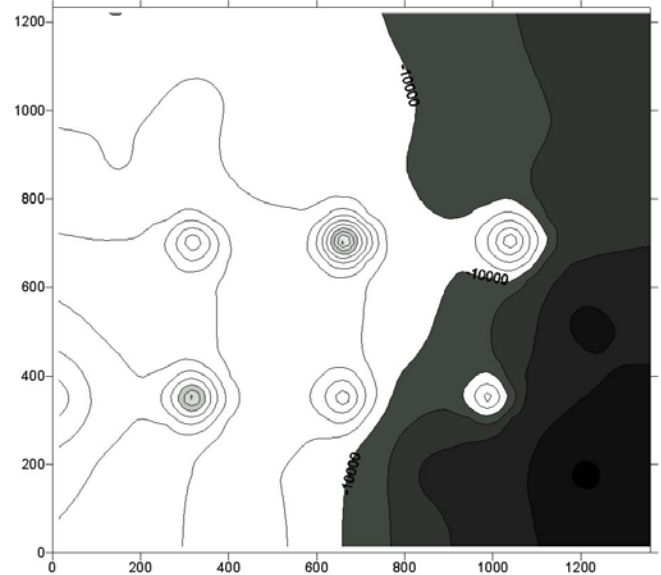


Fig. 7—Pattern pressures before ASP: Boundary is 10 MPa.

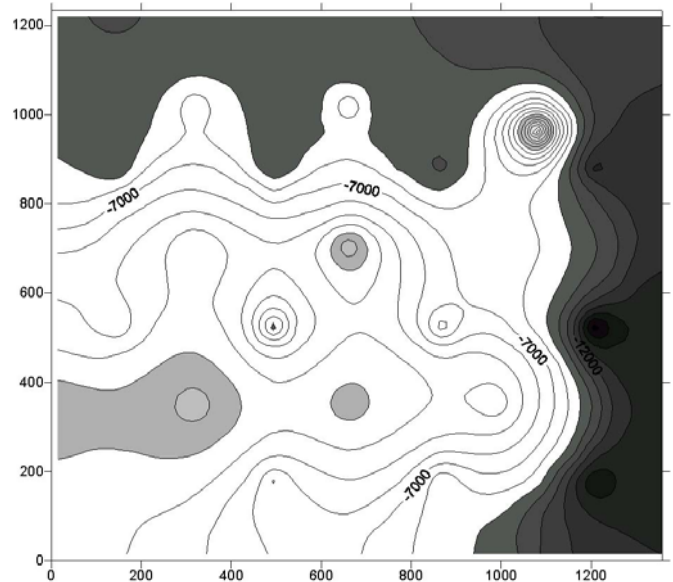


Fig. 8—Pattern pressures after ASP: Boundary is 12 MPa.

Are Fractures Important? Are Gels Viable to Reduce Channeling?

We examined whether fractures might cause significant channeling of polymer between some injector-producer pairs at Daqing. Typically, around 2,000 wells were intentionally hydraulically fractured each year at Daqing. Unintentional fracturing of injection wells is a possibility during waterflood operations. Also, natural fractures may exist. If fractures are

responsible for significant channeling between wells, gel treatments could be a viable solution. If fractures are not responsible for channeling, other sweep improvement options may be more appropriate.

In assessing whether fractures cause channeling, we considered three sets of data: (1) pattern oil recovery factors, (2) injectivity and productivity indexes, and (3) inter-well polymer breakthrough times.

Pattern Oil Recovery Factors. In examining our 25 wells, oil recovery factors were generally quite high for individual pattern areas—at least 33% original oil in place (OOIP) and more typically around 50% OOIP. Thus, if channeling through fractures was a problem, we must use means other than recovery factors to identify the offending fractures.

Injectivity/Productivity Indexes. One method to assess the importance of fractures is to compare the actual injectivity or productivity index for a well ($q/\Delta p$) with the value calculated using the Darcy equation for radial flow.¹²

$$q/\Delta p = \Sigma kh / [\mu \ln (r_e/r_w)] \dots\dots\dots (1)$$

If the left side of Eq. 1 is substantially greater than the right side, a fracture or fracture-like feature probably intersects the well. On the other hand, if the left side of Eq. 1 is less than or equal to the right side, fractures may not contribute significantly to the flow capacity of the well. We applied this method to our 25 Daqing wells. Most wells showed behavior that was consistent with radial flow (no significant fractures). However, the analysis revealed that fractures were present in three injection wells and three production wells. During polymer flooding, the injectivity or productivity indexes for these wells were typically three to five times greater than values calculated using the right side of Eq. 1.

For those wells where fractures were present, injectivity or productivity indexes can be used to estimate fracture widths (w_f).

$$k_f w_f = \{ [q \mu / (\Delta p h_f)] - [k_m / \ln(r_e/r_w)] \} L_f / 2 \dots\dots\dots (2)$$

$$w_f (\text{mm}) = 1.49 (k_f w_f)^{1/3}, \text{ where } k_f w_f \text{ is in } \mu\text{m}^2\text{-m} \dots\dots\dots (3)$$

In these equations, k_f is effective fracture permeability, q is the total fluid injection or production rate, μ is fluid viscosity, Δp is the well-formation pressure difference, h_f is fracture height, L_f is fracture half length, k_m is effective permeability of the porous rock (average $k_m = 0.259 \mu\text{m}^2$ at S_{or}), r_e is external drainage radius (~150 m), and r_w is wellbore radius (0.1 m). Using Eqs. 2 and 3 and data applicable during polymer injection, calculated fracture widths for the six target wells ranged from 1.4 to 5.0 mm. Interestingly, during water injection after polymer injection, these calculations suggested that the fracture widths ranged from 0 to 1.8 mm. Injection pressures were noticeably higher during polymer injection than during the subsequent water injection, so the fractures may have been more open during polymer flooding.

Inter-Well Polymer Breakthrough. The inter-well transit time for a tracer can also be used to assess whether channeling through fractures is important. We estimated the expected transit time (t) for flow through the matrix along the fastest streamline connecting an injection well and a production well. Eq. 4 was used to make this estimate.

$$t \approx L^2 \phi(1-S_{or}) \mu / (k_m \Delta p) \dots\dots\dots (4)$$

In this equation, L is the distance between wells (300 m or ~1,000 ft), ϕ is formation porosity (0.261), S_{or} is residual oil saturation (0.28), and Δp is pressure difference between the wells (20 MPa or ~2,900 psi). For most wells examined, the actual polymer breakthrough times (6 to 8 months) were reasonably consistent with the times calculated using Eq. 4, assuming flow through matrix (porous rock). However, for the six wells where injectivity/productivity data suggested the presence of fractures, the actual polymer breakthrough times were noticeably faster than those estimated using Eq. 4. So initially, we viewed this result as confirmation that fractures caused significant channeling between three injector-producer pairs.

If a fracture is dominantly responsible for channeling between two wells, Eq. 5 can be used to estimate the effective permeability of the fracture, and Eq. 6 can convert the effective fracture permeability to an effective average fracture width.

$$k_m \approx L^2 \mu / (t \Delta p) \dots\dots\dots (5)$$

$$w_f (\text{mm}) = 3.46 \times 10^{-3} (k_f)^{0.5}, \text{ where } k_f \text{ is in } \mu\text{m}^2 \dots\dots\dots (6)$$

Applying Eqs. 5 and 6 to our six candidate wells yielded estimates of effective fracture widths around 0.01 mm—far smaller than the 1- to 5-mm values from Eqs. 2 and 3. How can this discrepancy be explained? A credible possibility is that the fractures are significantly wider near the wells than deep within the formation. Calculations based on injectivity/productivity data are dominated by fracture widths near the well, while calculations based on inter-well tracer data are dominated by the most restricted part of the fracture (presumably far from the wells).

Are Gel Treatments Needed? We performed a simulation study to consider whether a gel treatment would improve sweep efficiency between an injector-producer pair with a connecting fracture. We assumed (1) the pattern area was 300 by 300 m, (2) the matrix permeability was uniformly $0.259 \mu\text{m}^2$, and (3) a pressure drop (Δp) of 20 MPa was applied between the two wells. Additional details of the simulation can be found in Ref. 13. We focused on the importance of areal locations of gel plugs in reservoirs with fractures.

For a fracture width of 1 mm, the pressure distribution is shown in Fig. 9. Because the pressure distribution is symmetrical about the fracture, only one-half of the pattern is illustrated. (The fracture is located on the front face of Fig. 9 and subsequent similar figures.) Fig. 10 shows the pressure distribution for the same half-pattern when no fracture connected the wells. For the open-fracture case, the flow rate

through the half-pattern was 4.7 times greater than for the no-fracture case. On the positive side, the fracture allowed the pattern to experience much higher injectivity and productivity indexes than the no-fracture case. However, on the negative side, most of the injected fluid simply channeled through the fracture. Also on the positive side, higher pressure gradients were distributed more deeply through the pattern for the open-fracture case than for the no-fracture case (compare Figs. 9 and 10). For the open-fracture case, 75% of the pattern experienced a pressure gradient over 34 kPa/m, while for the no-fracture case, only 26% of the pattern experienced a pressure gradient over 34 kPa/m. Of course, higher pressure gradients aid in driving oil from deep within the pattern. However, from a practical view, a 20 MPa pressure difference may be difficult to maintain across the pattern when the fracture is fully open. If high flow rates overwhelm the pumps, a lower pressure drop may result—leading to lower pressure gradients throughout the pattern than indicated in Fig. 9. Incidentally, it may help to view the pressure distributions in Figs. 9-11 as “waterfalls” or inclined surfaces that direct drainage of fluid from the pattern. Near-horizontal surfaces indicate poor drainage, while steep surfaces indicate rapid drainage.

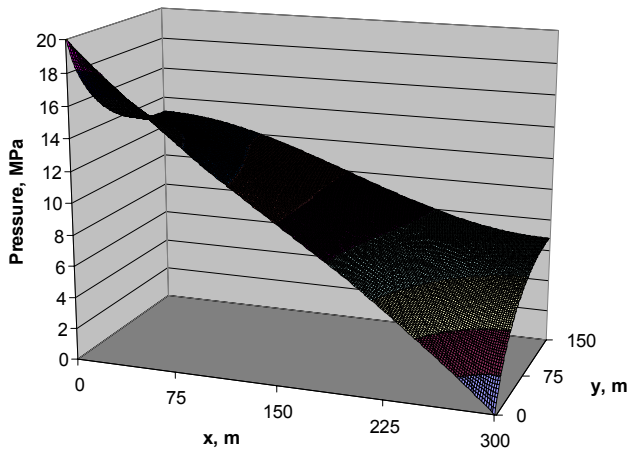


Fig. 9—Pressure distribution with a 1-mm wide fracture in 0.259- μm^2 rock.

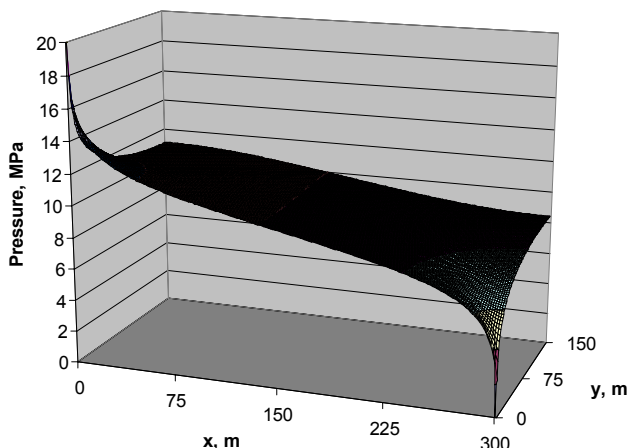


Fig. 10—Pressure distribution with no fracture present.

The greatest improvement in sweep occurs if the middle portion of the fracture can be plugged while leaving the fracture open near the wells.¹³ This situation allows a high fluid injectivity index, a high oil productivity index, and a fairly even sweep of most of the pattern.

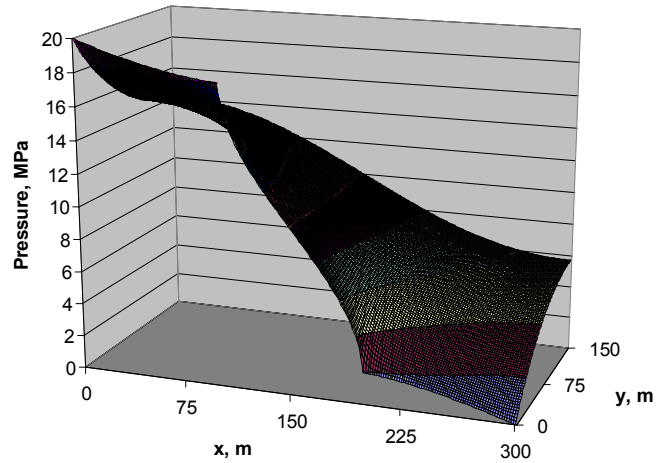


Fig. 11— $w_f = 1$ mm for the 1st and 3rd 100-m fracture sections; $w_f = 0.15$ mm in 2nd section.

For the three injector-producer pairs where we suspected channeling through fractures, the combined results from injectivity/productivity calculations and inter-well polymer breakthroughs indicated that fractures were more than 1-mm wide near the wells, but less than 0.02-mm wide far from the wells. Simulations were performed to examine sweep in the pattern with this and similar scenarios. Fig. 11 shows a representative result. In this case, the simulation assumed the fracture width was 1 mm from the injector to 100 m along the fracture, 0.15 mm for the middle 100 m of the fracture, and 1 mm for the final 100 m to the production well. Sweep efficiency was excellent, while injectivity and productivity indexes were high. The pressure gradient pattern shown in Fig. 11 was virtually identical to those from other simulations where the middle part of the fracture was narrower (or even when the middle fracture width was zero). The pattern in Fig. 11 was also very similar to cases where the near-wellbore parts of the fracture had widths greater than 1 mm.

The results in Fig. 11 and from similar simulations suggest that gel treatments are not needed for the three injector-producer pairs where fractures were present. Because the fractures are narrow far from the wellbore, severe channeling does not occur. On the contrary, the existence of the fractures near the wellbore aids reservoir sweep (compare the no-fracture case in Fig. 10 with Fig. 11). Furthermore, the near-wellbore fractures substantially increase the injectivity index during injection of polymer solutions and increase oil productivity index in the production wells (i.e., by a factor of 1.8 for the cases illustrated in Figs. 10 and 11).

Are “Colloidal Dispersion Gels” a Viable Option?

“Colloidal dispersion gels” (HPAM crosslinked with aluminum citrate) were field tested at Daqing.¹⁴ Claims were made for the success of these treatments at Daqing and elsewhere.¹⁴⁻¹⁷ However, before committing to a more

widespread application, the science and engineering of the “CDG” process should be carefully examined.

Consider how other gels perform in porous media.¹⁸⁻²³ Early in the gelation process, most gelants behave like clean fluids that do not contain suspended particulate matter.¹⁸⁻²³ However, after gel aggregates form and grow to the size of pore throats, gel filtration can radically increase the resistance to flow.¹⁸⁻²⁰ The literature indicates that gelants can penetrate a significant distance into porous rock before gelation, but after gelation, gel propagation is extremely slow or negligible.¹⁸⁻²³ Alternatively, if gelation is stopped sufficiently early or if gels are sufficiently sheared so that gel particles remain significantly smaller than pore throats, the gel suspensions can propagate through porous rock; however, the level of mobility reduction is generally small (less than 2).²⁴ Also, suspensions of gel particles and adsorbed polymers provide resistance factors and residual resistance factors that increase with decreasing permeability.^{21,25-29} Not surprisingly, suspensions of small gel particles are more effective at restricting flow through small pores than through large pores. Straight-forward calculations using the Darcy equation reveal that this behavior can be detrimental for sweep improvement—both during polymer flooding and gel treatments.⁸

In contrast to normal gel behavior, the aluminum-citrate-HPAM gels (after gel formation) were speculated to propagate through porous rock like viscous polymer solutions.¹⁴⁻¹⁷ Therefore, these gels were purported to act like mobility-control agents. If true, this mechanism of action would be radically different from that for other gels, which act exclusively as blocking or permeability-reduction agents.

The distinction between a blocking agent and a mobility-control agent is an important concept to understand. A mobility-control agent should penetrate as much as possible into the less-permeable zones so that oil can be displaced from poorly swept zones. In contrast, we wish to minimize penetration of blocking agents into the less-permeable, oil-productive zones. Any blocking agent that enters the less-permeable zones can hinder subsequent injected fluids (e.g., water) from entering and displacing oil from those zones.

Laboratory Behavior of Colloidal Dispersion Gels. We performed a coreflood to test how the aluminum-citrate-HPAM colloidal dispersion gels behave. The 0.7- μm^2 Berea sandstone core had a length of 14.7 cm and a diameter of 3.56 cm. An internal pressure tap was located 2.3 cm from the inlet sandface. A formulation was prepared that contained 300-mg/L HPAM (Tiorco HiVis 350TM), 15-mg/L aluminum (as citrate, Tiorco 677TM), and 0.5% KCl. All experiments were performed at 41°C. After saturating the 0.7- μm^2 Berea sandstone core with brine (0.5% KCl), 13 PV of polymer solution (300-mg/L HPAM without crosslinker) were injected and the same stable residual resistance factor was observed in both sections of the core. Later, polymer solution (also 300-mg/L HPAM) with crosslinker (15-mg/L Al as citrate) was injected at the same rate (6.8 PV per hr). This formulation was 1 hour old at the start of gelant injection. For the first 7 PV of gelant injection (requiring another hour), the resistance factors in the two core sections were stable, the same, and the same as during the previous injection of polymer solution without crosslinker. Thus, for this period, the behavior of the

aluminum-citrate-HPAM colloidal dispersion gel was the same as that for other gelants. Specifically, before the gelation time, the formulation behaved the same as a polymer solution without crosslinker.

Beginning at 7 PV of gelant injection (2 hours after the gelant was prepared), the resistance factor in the first core section increased (by more than a factor of 30), while the resistance factor in the second section decreased dramatically over the course of 3 additional PV of gelant injection. These results indicate that the time required for polymer crosslinking and formation of “colloidal dispersion” gel particles was only two hours at 41°C. The gel particles were clearly filtered out by the first core section—causing the resistance factors to rise rapidly. Resistance factors in the second section dropped because the polymer and gel were stripped from the solution in the first section.

Our results confirm that the aluminum-citrate-HPAM formulation basically behaves like other gels and gelants.¹⁸⁻²³ Early in the gelation process, it propagates through sandstone like a polymer solution without crosslinker. After some point (presumably when gel aggregates grow to the size of pore throats), gel propagation is extremely slow or negligible. Thus, aluminum-citrate-HPAM formulations should not flow through porous rock as a “super polymer” after gel formation.

The University of Texas³⁰ and the University of Kansas³¹ reported results consistent with our results, where the gel caused substantial permeability reduction only in the first section of a core. Both sets of researchers also extensively studied the ability of aluminum to propagate through porous rock. They found that effective propagation required high citrate/aluminum ratios and appropriate pH values.^{30,31} Aluminum precipitation and ion exchange played important roles in inhibiting aluminum propagation.

For conditions that allowed effective propagation of aluminum, researchers^{30,32} found that resistance factors (effective viscosities) provided by aluminum-citrate-HPAM colloidal dispersion gels within the core (i.e., beyond the first core section) were the same as those provided by polymer with no crosslinker. This observation suggests that either the gel particles were too small to interact significantly with pore throats or the crosslinking reaction did not take place to a significant extent. These possibilities are quite consistent with the behavior for other gels. If insufficient polymer or crosslinker is present, gel formation will not take place (even small gel particles may not form). With such low aluminum concentrations (as low as 15 mg/L), it is not surprising that a small loss of crosslinker (e.g., by ion exchange or precipitation) could preclude formation of adequate gel particles. (Formation of conventional gels was reported using aluminum concentrations of at least 200 mg/L, provided the ratio of citrate to aluminum was in the proper range.^{33,34})

Requirements for a Viable Colloidal Dispersion Gel. If one wished to develop and demonstrate positive behavior for a new suspension of gel particles, a number of useful and informative experiments could be performed. First, experiments must be performed using cores with multiple sections (e.g., multiple internal pressure taps). The injected formulation (1) must propagate into the rock without causing progressive plugging of the inlet sand face, (2) must show

uniform resistance factors and residual resistance factors along the various core sections, (3) must propagate these resistance factors through the porous rock at an acceptable rate (i.e., no excessive chemical retention), AND (4) must provide greater resistance factors/residual resistance factors than polymer solution alone. One must also be concerned about the magnitude of residual resistance factors as a function of rock permeability.^{21,25-29} This latter comparison must be made using cores that were completely filled with polymer or gel (i.e., NOT using misleading parallel corefloods). If residual resistance factors in low permeability rock are significantly greater than in high permeability rock, polymer or gel treatments can impair sweep efficiency.^{8,9}

Parallel corefloods, especially parallel linear corefloods, should NOT be used to evaluate the diversion properties of gels. These parallel corefloods are easily manipulated to give the appearance of successful fluid diversion.²⁵ Test results from parallel linear corefloods, in particular, cannot be directly translated to profile modification in radial flow (i.e., unfractured wells).^{8,9} Also, with short laboratory cores, diffusion and dispersion can readily compromise small gelant banks in the less permeable of the parallel cores—giving the false impression that gelant does not significantly enter or damage less permeable oil zones.³⁵ In real field applications, the distance of gelant penetration is several feet or more, even in the least permeable oil-productive zones.⁷⁻⁹ For these distances, diffusion and dispersion will not destroy gelant banks.³⁵

Consideration of Field Data. In general, the field results for applications of colloidal dispersion gels fit into one of several categories.⁹ In the first category, the treated wells contained no fractures or linear flow features. For these cases, the aluminum was probably either removed (by adsorption on rock) or was present in concentrations too low to allow crosslinking—so the polymer could propagate through the formation and provide some benefit as a polymer flood. This scenario is very consistent with the laboratory findings from the University of Texas³⁰ and the University of Kansas.³² Since the aluminum provided no benefit for this scenario, the money spent on aluminum citrate would have been more effectively spent on more polymer.

In the second field category, the treated wells probably contained fractures or fracture-like features (even though the operator or gel vendor may not have been aware of these before the treatments). For these cases, the gels may have provided some benefit from partially plugging the fractures. However, for moderate to wide fractures, other types of gels [e.g., Cr(III)-acetate-HPAM] probably would have been more effective. On a positive note for narrow fractures, colloidal dispersion gels conceivably may be more effective than other gels because of more effective penetration into tight fractures.^{36,37} This possibility requires further investigation.

In the third field category, the treated wells experienced general plugging of all open zones and flow paths. From an areal view, these wells were key to water channeling. By reducing the flow capacity of the treated wells, areal pressure gradients were altered so water injected into other (non-treated) wells pushed incremental oil toward offset production wells. This benefit could be realized by any means that

reduced the flow capacity of the treated wells. Well flow capacity can usually be reduced more cost-effectively using other gels and methods.

In the fourth field category, the reported benefits and/or increases in oil recovery had nothing to do with the colloidal dispersion gels. In some cases, the reported benefits for particular wells and fields occurred because of other changes or improvements that were implemented. In other cases, no real benefit occurred. The reported benefit resulted from an overly pessimistic projection of the pre-treatment decline curve and/or an overly optimistic assignment of incremental oil to the gel treatment.

Careful analysis of the Daqing field data presented in Ref. 14 and additional unpublished data associated with the project indicates no significant difference between the “CDG” flood and the normal polymer flood. Injectivity behavior was not significantly different for the two cases. (Injectivity was actually slightly higher during CDG injection.) Also, water/oil ratios and production trends cannot be credibly distinguished for the two processes. These results are consistent with the first category of field results mentioned above: the aluminum was either removed (by adsorption or precipitation) or was present in concentrations too low to allow crosslinking.

Mitigating Polymer Degradation

If channeling truly occurred during the applied polymer floods, it is possible that polymer degradation was responsible for sweep efficiency being lower than expected. This section considers causes of polymer degradation and their mitigation.

Mechanical or Shear Degradation. During preparation and injection, the polymer solution passed through a number of mixers, pumps, valves, filters, and pipes. Flow through this equipment can break polymer chains and decrease solution viscosity to some extent (called shear or mechanical degradation). Fig. 12 shows viscosity data of samples at different points along the polymer flow stream. Most viscosity loss occurred from the high pressure injection pumps and mixing system to the near-wellbore—amounting to about 64% of the total loss. Consistent with other work,³⁸ the greatest restriction to flow and the greatest mechanical degradation occurred from entering the porous rock at the high velocities at the injection sand face.

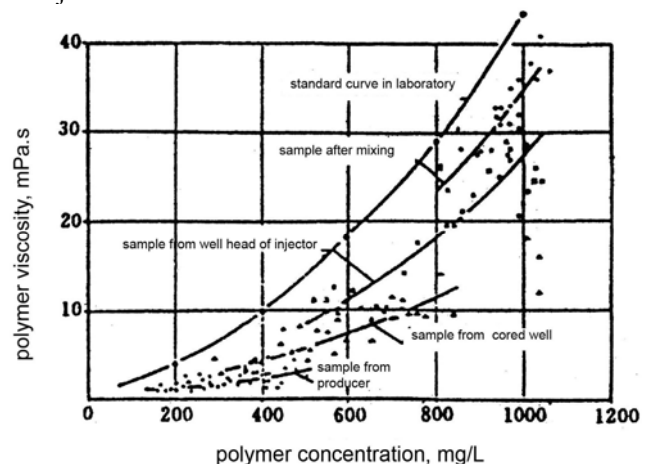


Fig. 12—Polymer solution viscosities at various points during injection.

The presence of a fracture in a well can mitigate mechanical degradation.³⁹ Fractures provide a dramatic increase in flow area at the injection sand face, thus decreasing the velocity of the polymer solution at this important constriction, and thereby reducing mechanical degradation. As mentioned earlier, the presence of fractures in wells can significantly increase well injectivity and productivity indexes. However, if fractures are used for these purposes, care must be taken so that the orientation and length of the fractures are not such that they accentuate channeling.^{40,41} The analysis presented earlier indicates that fractures in the target Daqing wells satisfy this requirement. Consequently, there may be considerable value in intentionally fracturing (and perhaps propping) injection wells during future chemical flooding projects at Daqing.

Oxidative Degradation. Fresh water was used to prepare polymer solutions in the Daqing field projects. This water had a high concentration of dissolved oxygen, and no processing was used to remove it. The presence of dissolved oxygen, free radicals, and/or a redox couple can severely degrade HPAM polymers.^{42,43} Thus, oxidative degradation could be a serious concern. Three observations help to mitigate this concern. First, the reservoir temperature is relatively low (45°C), which should inhibit free radical generation. Second, oil in the reservoir should combine with oxygen and (hopefully) eliminate it. Third (and most convincingly), polymer produced from the reservoir was not reduced in molecular weight by more than 50% compared to the injected polymer. If oxidative degradation was important, the polymer should have been degraded to a low molecular weight, and polymer solution viscosity should have been reduced to that near water.^{42,43} Thus, mechanical degradation (as discussed above) seems a more serious issue for Daqing than oxidative degradation. If future efforts are made to reduce dissolved oxygen in the water, gas stripping is probably a more technically and economically effective method than use of chemical oxygen scavengers.

Microbial Degradation. In concept, microbial attack could also lead to polymer degradation and viscosity loss. However, two factors indicated that microbial degradation was not responsible for the viscosity losses noted at Daqing to date. First, although microorganisms have been known to metabolize the side groups on HPAM and to flocculate with the polymer, degradation of the HPAM backbone has not been proven. Second, evidence of extensive microbial activity at Daqing has not been reported.

Of course, biocides can be used to mitigate concern about microbial degradation. A successful test was performed using a biocide in Shuanhe in the Henan oil field, where the reservoir temperature was 72°C.

More Viscous Polymer Solutions

Using Higher Polymer Concentrations. Mobility ratios and reservoir sweep can be improved by injecting more viscous polymer solutions—i.e., solutions with higher polymer concentrations. This basic concept from accepted reservoir

engineering concepts can readily be confirmed using numerical simulation. Given the same volume of injected polymer solution, higher polymer concentrations yield more oil production (OOIP). An added benefit is that the higher polymer concentrations are more tolerant to mechanical degradation.⁴⁴ Furthermore, they impart greater solution viscoelasticity, which provides higher oil recoveries and lower residual oil saturations under Daqing conditions.⁴⁵

From the two pilot tests⁴⁶ at Daqing (specifically, at areas called “West of Center” and “4-4# Station of the Northwest in Lamadian”), the following observations were noted: (1) Water intake profile was improved after injecting higher polymer concentrations. (2) During polymer flooding, the period of relatively low water cuts can be prolonged by injecting higher polymer concentrations. (3) Interestingly, injection of more concentrated polymer solutions (2,000 - 2,500 mg/L rather than 1,000 mg/L) did not result in substantially increased injection pressures.⁴⁶ This result suggests that fractures exist near the wells. If these fractures are extended during injection of the more viscous polymer solutions, increases in injection pressure will be mitigated. Both tests involving higher polymer concentrations were implemented in the later stages of the main polymer flood. In both cases, the tests were begun after the main response to the polymer flood had occurred and water cut had resumed its rise. (As mentioned above, injection of the more concentrated polymer alleviated this rise in water cut.) These tests are still underway, so the economic viability of this process change must await further results, and be evaluated in light of the chemical costs, oil price, and geographic factors associated with the test site. Another pilot test was initiated in May 2005 in a Daqing pattern that was not previously polymer flooded (1# of East Area of the First Area of South). This test may provide the most definitive evaluation of the high-polymer-concentration process. As of April 2006, about 0.1 PV of polymer solution has been injected. Injection pressures are only 1 MPa greater than an adjacent area where polymer solution with the original (lower) concentration was injected. Current injection pressures are thought to be below the fracture pressure (3 to 4 MPa). The project will continue to be monitored.

New Salinity-Tolerant Polymer. A new salinity-tolerant polymer^{47,48} (called “KYPAM”) was developed at Daqing that provides higher viscosities in saline waters than those provided by conventional HPAM polymers. This new copolymer incorporates a small fraction of new monomers with acrylamide to form comb-like copolymers. There are currently two varieties of this “KYPAM” polymer. One has a high molecular weight (20-25 million daltons) and uses as the functional group—AHPE (aromatic hydrocarbon with ethylene). At present, we are most interested in the second variety, which has medium (12-17 million daltons) or low (3-11 million daltons) molecular weight. The medium molecular weight copolymer incorporates the monomer, 2-mercaptobenzimidazole, while the low molecular weight copolymer contains RSO (sulfhydryl).

Table 3 compares viscosities for the new polymer with conventional HPAM polymers—one with ultra-high molecular weight (35 million daltons) and one with low-to-medium molecular weight (7-15 million daltons). Viscosities were

measured in waters with two salinities—1,000 mg/L and 4,000 mg/L. The salinity-tolerant polymer provided the highest viscosity in the more saline water, and it experienced a smaller percentage change in viscosity in the two waters.

The above polymers can all be produced at about the same cost, so polymer performance is the main criterion of importance. In more saline waters, the salinity-tolerant polymer will be preferred. For very fresh waters and high-permeability rock, the ultra-high Mw polymer will be preferred. In very fresh water and less-permeable rock, the medium Mw polymer may be most functional.

Table 3—Viscosities for solutions with 1,000 mg/L polymer, 45°C

Salinity (mg/L)	1,000	4,000	Ratio, %
Ultra-high Mw HPAM	82.8 mPa-s	40.3 mPa-s	48.7
Salinity-tolerant polymer With medium Mw	62.2 mPa-s	52.3 mPa-s	84.1
Medium Mw HPAM	38.9 mPa-s	16.8 mPa-s	43.2

Using Other New Polymers. A new water-soluble hydrophobic associative polymer (called AP-P4) was tested in Zhongyuan Oil Field in Central China. Based on preliminary results from the pilot, Well W94-4 produced 4.5 tons/day of incremental oil. Water cut declined 4%.

This polymer can be dissolved as rapidly as HPAM—for example, a solution with 5,000 mg/L can be prepared in 2 hours if the temperature is greater than 35 °C.⁴⁹ Compared to the KYPAM polymer, AP-P4 can provide greater viscosity.

At present, the cost of this new hydrophobic associative polymer is 10% more than HPAM polymers, but it can provide a larger financial internal rate of return. Further laboratory testing is underway to determine if the new hydrophobic associative polymer will provide superior performance to HPAM in the important areas of polymer stability and retention.

Recently, displacement experiments were performed comparing xanthan and HPAM.⁴⁶ For either a given polymer concentration or viscosity level, HPAM solutions provided significantly greater oil recovery levels under Daqing conditions. This result was believed to occur because HPAM solutions exhibited significantly greater viscoelasticity than xanthan solutions.

Use of Less Saline Water. HPAM and other anionic polymers are well known to provide much higher viscosities in fresh water than in saline waters. Maitin⁵⁰ demonstrated that low salinity HPAM solutions can sweep effectively through high salinity reservoirs (i.e., without destructive mixing and salinity increase in the polymer bank) if mobility control is maintained. At Daqing, the lowest water salinity used for polymer mixing contained about 300 mg/L total dissolved solids (TDS). However, significant variations in water salinity occur. Water quality varies with the amount of rain, surface temperature, and humidity during the four seasons. Also, the content of Ca²⁺ and Mg²⁺ in the Daqing water is lower in summer and higher in winter.

Can reverse osmosis be practically applied to prepare polymer solutions with less than 200 mg/L TDS at Daqing? This question remains to be investigated. At present, use of available fresh water (~400 mg/L TDS) for polymer mixing costs \$0.49/m³ more than use of produced water (~3,000 mg/L TDS). Current thinking at Daqing is directed more toward development of polymers that provide the desired viscosities and resistance factors using Daqing produced water.

Are Foams a Viable Option?

Limiting Capillary Pressure. In concept, foams are low-mobility gas/water/surfactant formulations that could replace polymer solutions for mobility control.^{51,52} In addition to the sweep benefits from injecting a low-mobility fluid, the limiting capillary pressure phenomenon may provide an additional advantage: formation of a low-mobility foam in high-permeability zones while a non-foaming, high-mobility gas/water composition flows freely through low-permeability zones. Foam flow generally occurs in one of two regimes.⁵¹ In one regime, foam quality is low (low gas fraction), and gas mobility is quite low. However, liquid velocity is quite dependent on pressure gradient. In the second regime, limiting capillary pressure is effective in collapsing the foam, foam “quality” is high (high gas fraction), and gas velocity is insensitive to pressure gradient over a wide range.

To briefly explain the limiting capillary pressure concept, consider two gas bubbles that are flowing through a porous medium. Because of their close proximity, these bubbles are separated by a film of water. A pressure difference, called the capillary pressure, exists between the gas phase and the liquid phase. The limiting-capillary-pressure concept recognizes that if the capillary pressure is too great, water will be sucked away from the film, the film separating the bubbles will collapse, and the bubbles will coalesce. The capillary pressure at which this coalescence occurs is called the limiting capillary pressure. Greater hydrophilic rock surface area associated with less permeable rock promotes foam collapse in low permeability rock.⁵³

Although foams have significant potential, they have significant deficiencies and disadvantages. First, propagation through a reservoir rock can be severely limited by surfactant retention and partitioning into oil. Second, costs to compress and inject gas or foam can be quite high. Third, significant laboratory tests may be needed to identify conditions that allow effective foam generation and especially exploitation of the limiting capillary pressure effect.

ASP Foam Flooding ASP Foam (ASPF) flooding was developed as a new EOR technology, combining foam flooding and ASP flooding. Consisting of alkali, surfactant, polymer and gas, the ASPF system not only can greatly reduce the interfacial tension (IFT) between the crude and the complex system, and thus increase the displacement efficiency, but also can reduce the mobility ratio to enlarge the swept volume. Therefore, ASPF flooding could enhance oil recovery more than ASP flooding. A successful field test of the first ultra-low interfacial tension foam flood was performed at Daqing.⁵⁴ This project increased volumetric sweep efficiency, and the final recovery should be around 70% OOIP.

Foam Stability in ASPF Floods. Surfactant, polymer, and alkali all impact foam stability. Of course, foam generation and stability are strongly influenced by the type and concentration of surfactant.⁵⁵ Surfactant bilayers are essential to generate and stabilize the thin liquid films that separate the gas bubbles that comprise the foam. The surfactants are also needed to provide ultra-low interfacial tension in the ASP process. Thus, either one surfactant must fulfill dual functions, or if two or more surfactants are used, their actions must not have a negative interference with the function of the other surfactant.

Polymer concentration and molecular weight are also well known as factors that impact foam stability.⁵⁶ Foam stability is directly related to the rate of liquid drainage from films, which in turn is directly related to liquid viscosity—which are, of course, impacted by polymer concentration and molecular weight.

Since salinity impacts surfactant behavior and foam stability^{55,57} and since salinity is directly related to alkali concentration, foam stability is affected by the alkali. Increased salinity acts to screen charged surfactants in solution, thereby affecting surfactant aggregation (e.g., critical micelle formation and film formation).^{55,57} Alkali can neutralize organic acids in oils, generating additional surfactants that may act in either a positive or negative manner with existing surfactants that are intended to generate foams.⁵⁸

During the Daqing field test of the first ultra-low interfacial tension foam flooding,⁵⁴ a relatively stable foam slug was formed in the formation. Injection pressures during this ASPF pilot were higher than when injecting water, HPAM, or ASP formulations. The gas/oil ratio (GOR) after this ASPF pilot was significantly lower than when this same area was on WAG flooding. This result also supports that foam was formed in the formation and prevented gas fingering and channeling.⁵⁴

Thermal Recovery or MEOR

For the ultra-low permeable areas in Daqing Oil Field, thermal recovery methods (i.e., steam cycling and steam drive) and “Bio-Huff-Puff” are also methods that are under consideration for sweep improvement.

A “Bio-Huff-Puff” pilot test was successfully conducted in 47 wells in the Chaoyanggou area of Daqing in 2002. The Bio-Huff-Puff process uses microorganisms to improve injection profiles. The 47-well test achieved a positive response in the main oil zones for 80% of the treated wells. Based on this successful pilot, the test scale was enlarged in 2003. Laboratory results indicate that 7.2% OOIP EOR can be achieved in some cases using microbial profile modification methods after polymer flooding.

A field test of steam cycling was successful in ultra-low permeable oil zones in another area of Chaoyanggou—proving that this can be another choice for sweep improvement.

Pattern Spacing

Consideration of the effects of pattern spacing on sweep efficiency during polymer flooding is included in Ref. 59.

Conclusions

Sweep improvement in the Daqing Oil Field was considered using various approaches. Given that the reservoir description and polymer input data were correct, the polymer flood should have provided excellent sweep throughout the majority of the Daqing patterns under consideration. If ASP flooding is applied to increase recovery efficiency, mobility control and sweep improvement will be especially important and challenging during implementation.

In a number of Daqing wells (both injectors and producers), fractures were present. These fractures were narrow far from the wellbore, so channeling was not significant. On the contrary, these near-wellbore fractures aided reservoir sweep. They substantially increased the injectivity index during injection of polymer solutions and increased oil productivity index in the production wells. Near-wellbore fractures with the proper length, orientation, and width may play a crucial role during future floods if very viscous chemical (i.e., ASP) banks must be injected to maintain mobility control. Appropriate use of near-wellbore fractures may also mitigate mechanical degradation.

Cost-effective improvements at Daqing may be realized using one or more new polymers. ASP foams, steam, and microbes showed positive indications during field tests. Analyses of laboratory and field results raise doubts about the viability of colloidal dispersion gels. Additional work may be warranted concerning the potential of foams and polymer solutions prepared with reduced salinity.

Nomenclature

h	= formation height, m
h_f	= fracture height, m
k_f	= fracture permeability, μm^2
k_m	= permeability of matrix or porous rock, μm^2
L	= distance between wells, m
L_f	= fracture half length, m
Δp	= pressure drop, Pa
dp/dl	= pressure gradient, psi/ft [Pa/m]
PV	= pore volumes of fluid injected
q	= flow rate, m^3/d
r_e	= external drainage radius, m
r_w	= wellbore radius, m
S_{or}	= residual oil saturation
w_f	= fracture width, mm
t	= breakthrough time, d
ϕ	= porosity
μ	= viscosity, mPa-s

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SI Metric Conversion Factors

cp x 1.0*	E-03	= Pa·s
ft x 3.048*	E-01	= m
in. x 2.54*	E+00	= cm
md x 9.869 233	E-04	= μm ²
psi x 6.894 757	E+00	= kPa

*Conversion is exact.