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USING CHEMICALS TO OPTIMIZE CONFORMANCE CONTROL IN FRACTURED RESERVOIRS

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By
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ABSTRACT

This technical progress report describes work performed from October 1, 1998 through December 31, 1998, for the project, "Using Chemicals to Optimize Conformance in Fractured Reservoirs." In our first task area, disproportionate permeability reduction, a literature survey and analysis are underway to identify options for reducing permeability to water much more than that to oil. In our second task area, we are encouraging the use of our recently developed software for sizing gelant treatments in hydraulically fractured production wells. In several field applications, we noted the importance of obtaining accurate values of the static reservoir pressure before using our program. In our third task area, we examined gel properties as they extruded through fractures. We found stable pressure gradients during injection of a large volume of a one-day-old Cr(III)-acetate-HPAM gel into a 0.04-in.-wide, four-ft-long fracture. This finding confirms that gel injection (under our specific circumstances) did not lead to continuously increasing pressure gradients and severely limited gel propagation. Our experiments also provided insights into the mechanism for gel propagation during extrusion through fractures.

PROJECT OBJECTIVES

This research project has three objectives. The first objective is to develop a capability to predict and optimize the ability of gels to reduce permeability to water more than that to oil or gas. The second objective is to develop procedures for optimizing blocking-agent placement in wells where hydraulic fractures cause channeling problems. The third objective is to develop procedures to optimize blocking-agent placement in naturally fractured reservoirs. This research project consists of three tasks, each of which addresses one of the above objectives. Our work is directed at both injection wells and production wells and at vertical, horizontal, and highly deviated wells.

RESULTS AND DISCUSSION

Task 1: Disproportionate Permeability Reduction. Polymers and gels can, under certain circumstances, reduce permeability to water much more than that to oil.[1] This property can be very valuable for gelant treatments in fractured production wells,[2] even if the residual resistance factor for oil is significant (e.g., up to 100). However, if production wells do not contain fractures (i.e., flow is radial) and oil zones are not protected during polymer or gel placement, residual resistance factors for oil typically must be less than 2 to prevent serious damage to oil productivity. Unfortunately, a critical examination of previous work reveals that polymers and gels have not reliably or predictably provided low oil residual resistance factors simultaneously with large water residual resistance factors. We are performing a literature survey and an analysis to identify and compare different approaches to obtaining an acceptable disproportionate permeability reduction in unfractured wells. In addition to polymers and gels, some of the materials and approaches that we are investigating include (1) oil-soluble particulate resins, (2) foams that collapse when contacting oil, (3) chemical reactions that rely on partitioning between oil and water, and other concepts. We plan to complete this analysis by mid-1999.

Task 2: Gelant Treatments in Hydraulically Fractured Production Wells. In previous work, we developed a method for sizing gelant treatments in hydraulically fractured production wells.[2] The method was incorporated in user-friendly graphical-user-interface software (available at our web site at http://baervan.nmt.edu/ResSweepEffic/reservoir.htm). For recent field applications of the software, we noted several cases where engineers overestimated the static reservoir pressure (used as input for the program). This situation occurred because the engineers either used the original reservoir pressure or an outdated or inappropriate estimate of the reservoir pressure (e.g., a pre-fracture measurement or a measurement from a different part of the field). Consequently, the pressure drawdown used as input for our software was too high, and the program identified the wells (possibly incorrectly) as bad candidates for a gelant treatment. This experience emphasizes the need for recent, accurate pressure data for the target well, if our program is to be used.

Task 3: Gels in Naturally Fractured Reservoirs. Some of the most successful water shutoff treatments used gels (rather than fluid gelants) that extruded through fractures during the gel placement process.[3-6] Therefore, an understanding of gel extrusion is important for these applications. In previous work[7-10] we demonstrated that a minimum pressure gradient is required to extrude a given gel through a fracture. Once this minimum pressure gradient is exceeded, the pressure gradient observed during gel extrusion is insensitive to the flow rate. Also, the pressure gradient required for gel extrusion varies inversely with the square of fracture width. We also found that gels can concentrate or dehydrate (e.g., by factors up to 50) during extrusion through fractures. This dehydration effect can significantly retard gel propagation.

In previous work using four-ft-long fractured cores, less than 20 fracture volumes of gel were typically injected. In these experiments, pressure gradients appeared to stabilize along the fracture during gel injection at a fixed flow rate. In order to ensure that the pressure gradients did not increase during injection of larger volumes of gel, we performed a test where 80 fracture volumes (3,700 cm^3) of a one-day-old Cr(III)-acetate-HPAM gel [0.5% Alcoflood 935 HPAM, 0.0417% Cr(III) acetate] were extruded through a four-ft-long fractured core. This core was prepared from 650-md Berea sandstone using our standard method.[7-10] The effective average fracture width was 0.04 in. (0.1 cm), and the average fracture conductivity was 277 darcy-ft. Four equally spaced internal taps were positioned to measure pressures along the length of the fracture. We also placed internal taps to measure pressures along the length of the porous rock. These taps divided the core into five sections of equal length. A special outlet fitting segregated the effluent from the fracture and that from the porous rock.[7]

Fig. 1 shows the pressure gradients in the fracture for the five fracture sections during gel injection using a rate of 200 cm^3/hr. At the end of gel injection, the average pressure gradient in the fracture was 28 psi/ft for the first three fracture sections and 50 psi/ft in the last two fracture sections. This result suggests that the last two fracture sections were slightly narrower and less conductive than the first three fracture sections. In Fig. 1, note that the pressure gradients were fairly stable during the last 60 fracture volumes of gel injection. This finding confirms that gel injection (under our specific circumstances) did not lead to continuously increasing pressure gradients and severely limited gel propagation.

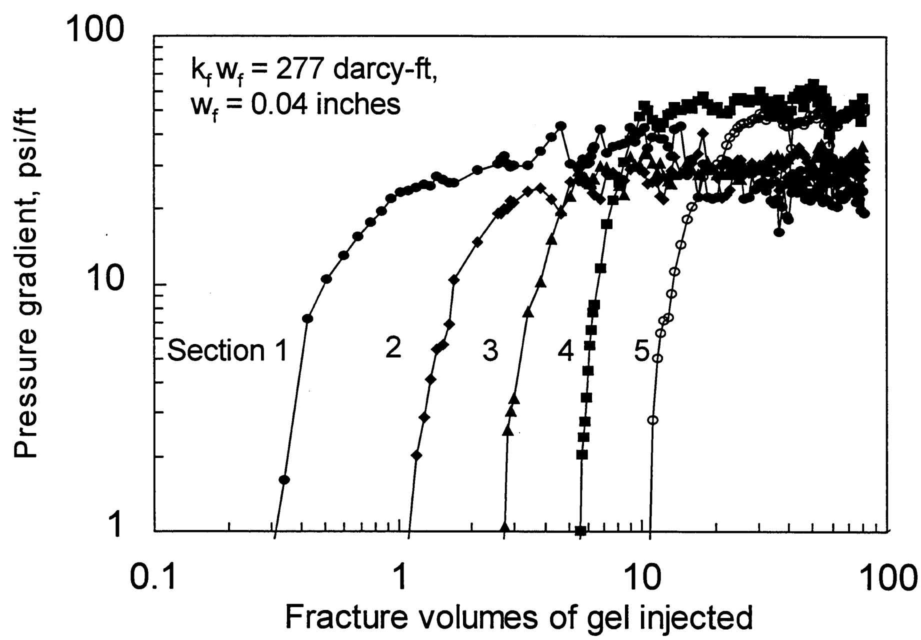

Fig. 1—Pressure behavior in the fracture taps during gel injection.

The pressure response in Fig. 1 indicates the rate of gel propagation through the fracture. In particular, gel arrived at the beginnings of Fracture Sections 2, 3, 4, and 5 after injecting 1.1, 2.7, 5.6, and 11 fracture volumes of gel, respectively. (Fig. 1 also suggests that 0.3 fracture volumes of gel must be injected before it arrives at the beginning of Section 1. Of course, this result simply indicates the experimental error associated with timing at the start of the experiment.) Gel was first detected in the effluent from the fracture after injecting 15 fracture volumes of gel. Fig. 2 indicates the rate of gel propagation in the five fracture sections relative to that expected for a displacement with no retardation or dispersion of the gel front in the fracture. In the first fracture section, the rate of gel propagation was about one-fifth that for a perfect displacement, while in the fourth and fifth fracture sections, gel propagated at about one-twenty-fifth of the rate for a perfect displacement.

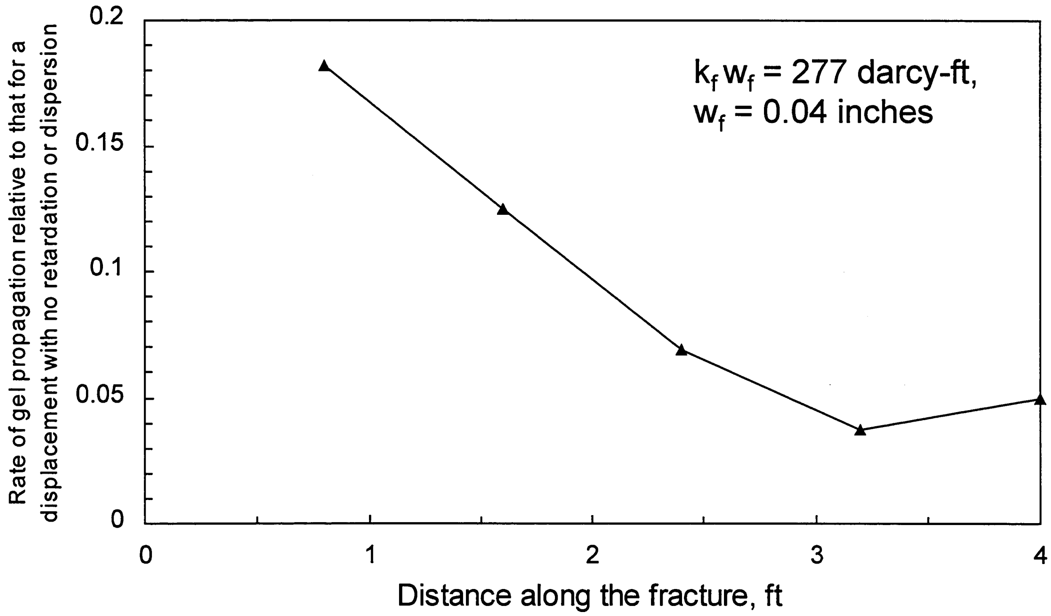

Fig. 2—Gel propagation rate in the fracture.

Using pressure data from the matrix taps and the Darcy equation, we calculated the fraction of total flow that occurred through the rock matrix at any given time.[7] Fig. 3 plots the results of this determination. (Of course, the source of this flow is water that left the gel in the fracture—i.e., water from the gel dehydration process.) For a given position along the core, Fig. 3 reveals that flow through porous rock does not become significant until the gel front reaches that corresponding position in the fracture. Shortly after arrival of the gel front in the adjacent fracture, flow in the porous rock rises to a maximum between 35% and 60% of the total flow (i.e., a minimum between 40% and 65% of the total flow occurs in the fracture). Then, the fraction of fluid flow in the matrix gradually declines. After injecting 80 fracture volumes of gel, the fraction of the flow in the matrix ranged from 0.1 to 0.35. During these experiments, we verified that water was the only fluid that flowed in the matrix while gel flowed exclusively through the fracture.

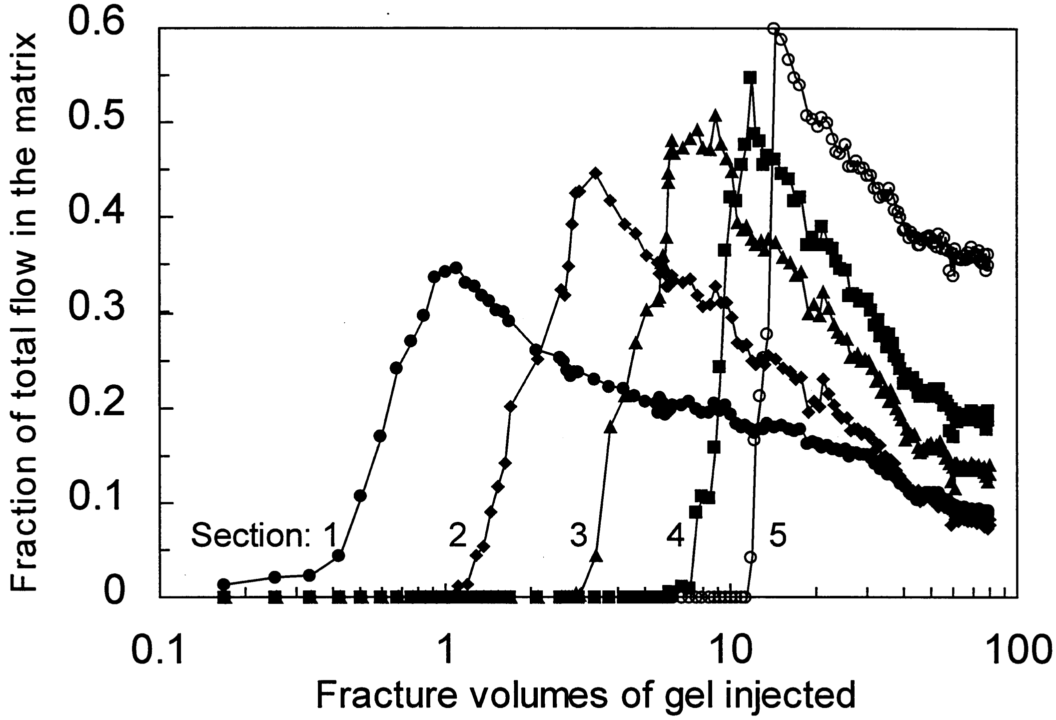

Fig. 3—Fraction of flow occurring in the matrix during continuous gel injection.

As mentioned earlier, a special outlet fitting was made to segregate the effluent from the fracture and that from the porous rock. Fig. 4 plots the fraction of the effluent that was produced from the fracture versus from the porous rock—i.e., at the outlet of the fractured core. (In contrast, Fig. 3 estimates this information inside the core—averaged over a given core section.) During the first 15 fracture volumes of gel injection, Fig. 4 indicates that virtually 100% of the flow occurred in the fracture. This result was expected. Before gel injection, the calculated flow capacity of the fracture was 3,400 times greater than the flow capacity of the porous rock. Gel arrival at the fracture outlet was noted after injecting 15 fracture volumes of gel. Coincident with gel arrival, flow from the fracture abruptly stopped for a period of about 2 fracture volumes of gel injection. (So, 100% of the effluent was produced from the matrix during this time.) Subsequently, the fraction of flow from the fracture increased, while flow from the porous rock decreased. After injecting 80 fracture volumes of gel, flow from the fracture accounted for 65% of the total flow, while flow from the matrix accounted for 35% of the total flow. This fractional flow information was consistent with the final fractional flow data shown in Fig. 3 for the fifth section of the core.

The physical appearance of the gel from the fracture outlet was the same as that for the injected gel. Also, the composition of the gel from the fracture outlet was similar to that for the injected gel. The chromium concentrations are plotted in Fig. 5 for effluent samples from the fracture and the matrix. This figure confirms that the fracture provided the only conduit for the gel. After chromium breakthrough, the chromium concentration averaged 1.17 times that of the injected gel. Chromium concentrations for the matrix effluent were negligible.

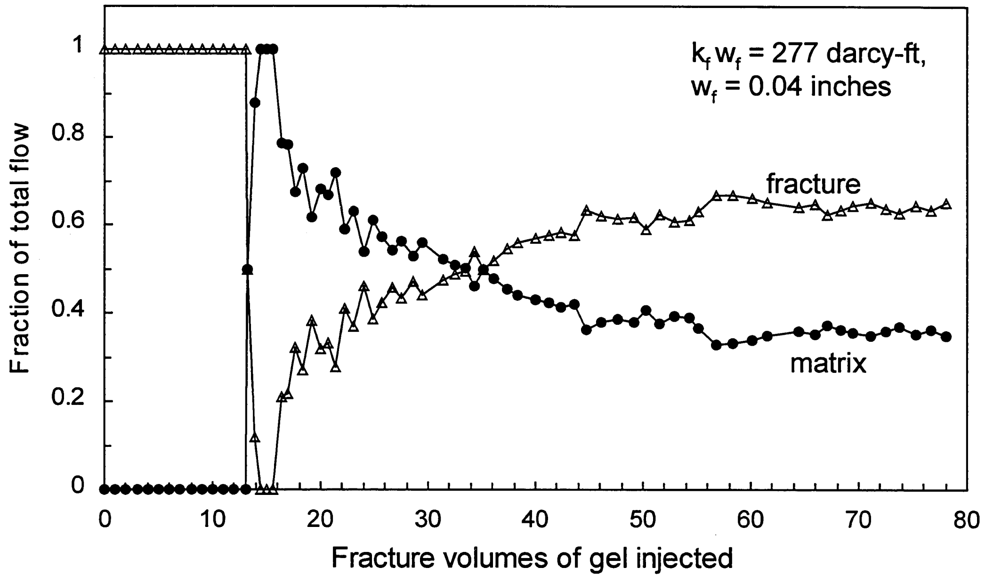

Fig. 4—Fractional flow measured at the core outlet.

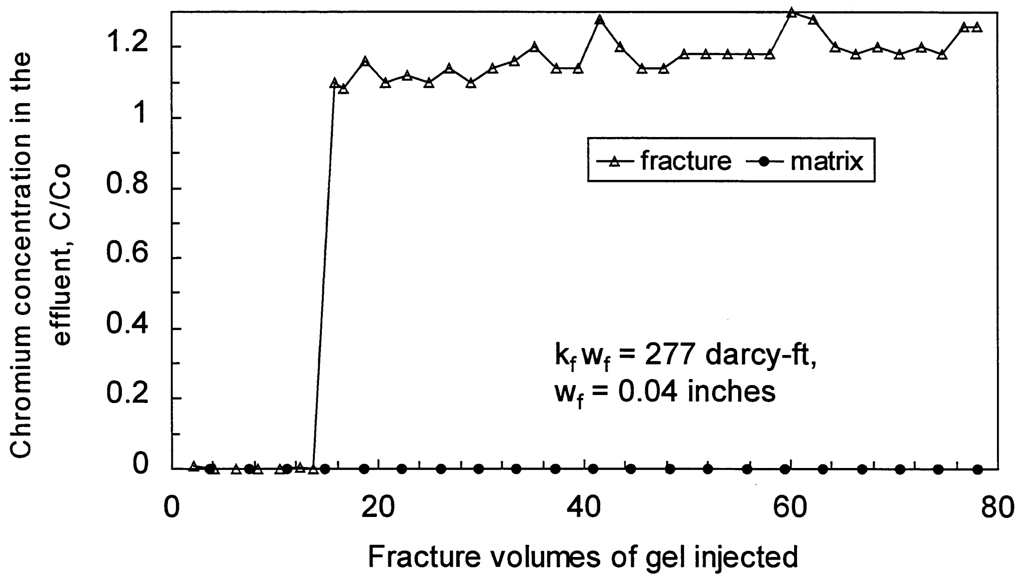

Fig. 5—Chromium concentrations in the effluent: fracture versus matrix.

Interestingly, Fig. 4 suggests that after 80 fracture volumes, newly injected gel, on average, concentrated by 35% (because water produced from the matrix stabilized at 35% of the total flow). For comparison, Fig. 5 suggests that after 80 fracture volumes, the gel concentrated by about 20%. Figs. 1, 4, and 5 indicate that near the end of the experiment, a steady state was attained. Therefore, some dehydrated gel must propagate through the fracture. In contrast, in a previous report,[7] we suggested that the only mobile gel in the fracture had the same composition as that for the injected gel. Two possibilities are evident. First, the propagating gel may be homogeneous (i.e., with a uniform concentration that was 20 to 35% greater then the injected gel). Alternatively, the propagating gel may be a mixture of two components. The injected gel may comprise the dominant component, while a minor component may be very concentrated gel with the composition of the material found in the fracture at the end of the experiment (i.e., gel that was 10 to 20 times more concentrated than the injected gel).[7] In other words, at steady state, we suggest that pressure gradients may be sufficient to mobilize a small amount of the dehydrated gel. More work is needed to distinguish between these possibilities.

CONCLUSIONS

We found stable pressure gradients during injection of a large volume of a one-day-old Cr(III)-acetate-HPAM gel into a 0.04-in.-wide, four-ft-long fracture. This finding confirms that gel injection (under our specific circumstances) did not lead to continuously increasing pressure gradients and severely limited gel propagation. We also found evidence that the average gel composition for gel that propagates through a fracture is slightly more concentrated than the injected gel. Future work will attempt to explain why this result occurs.

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