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A Comparison of Polymer Flooding With In-Depth Profile Modification

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Abstract

For stratified reservoirs with free crossflow and where fractures do not cause severe channeling, improved sweep is often needed after water breakthrough. For moderately viscous oils, polymer flooding is an option for this type of reservoir. However, in recent years, an in-depth profile modification method had been commercialized where a block is placed in the high-permeability zone(s). This sophisticated idea requires (1) the blocking agent must have a low viscosity (ideally a unit-mobility displacement) during placement, (2) the rear of the blocking-agent bank in the high-permeability zone(s) must outrun the front of the blocking-agent bank in adjacent less-permeable zones, and (3) an effective block to flow must form at the appropriate location in the high-permeability zone(s). Achieving these objectives is challenging but has been accomplished in at least one field test. This paper asks: When is this in-depth profile modification process a superior choice over conventional polymer flooding?

Using simulation and analytical studies, we examined oil recovery efficiency for the two processes as a function of (1) permeability contrast, (2) relative zone thickness, (3) oil viscosity, (4) polymer solution viscosity, (5) polymer or blocking-agent bank size, and (5) relative costs for polymer versus blocking agent. The results reveal that in-depth profile modification is most appropriate for high permeability contrasts (e.g. 10:1), high thickness ratios (e.g., less-permeable zones being 10 times thicker than high-permeability zones), and relatively low oil viscosities. Because of the high cost of the blocking agent (relative to conventional polymers), economics favor small blocking-agent bank sizes (e.g. 5% of the pore volume in the high-permeability layer). Even though short-term economics may favor in-depth profile modification, ultimate recovery may be considerably less than from a traditional polymer flood.

Introduction

Heterogeneity is well known to reduce sweep efficiency during waterflooding and other flooding processes. Depending on the nature of the heterogeneities, a number of methods are available to improve sweep efficiency. For example, if continuous impermeable barriers separate high-permeability watered-out strata from less-permeable oil-productive strata, one can use cement, mechanical methods, or certain chemical plugging agents to block off the offending high-permeability zones (at the wellbore) so that injected water only enters and displaces oil from the less-permeable zones. As another example, if a fracture or fracture system causes direct channeling between wells, gels can be extruded deep into the fractures to allow subsequently injected fluid to be diverted to displace oil from the rock matrix (Sydansk and Romero-Zeron 2011). This paper is directed at a third scenario, where fluids can crossflow between strata but fractures do not contribute significantly to channeling. Improving sweep efficiency for this case is generally acknowledged as considerably more challenging than that for the first two cases (Seright *et al.* 2003).

Polymer Flooding. Polymer flooding is one method to attack this difficult problem (Willhite and Seright 2011). Fig. 1 illustrates the benefits of a polymer flood in a two-layered system with free crossflow. This figure shows five displacements of water by red-dyed polymer solutions, with xanthan solutions ranging in concentration from 0 ppm to 2,000 ppm and viscosities (at 11 s^{-1} , 25°C) ranging from 1 to 75 cp. In each case, the plexiglass-encased beadpack had dimensions of 238 cm x 11.6 cm x 1.3 cm. A 5.8-cm high layer of 150- μm glass beads comprised the bottom layer, while a 5.8-cm high layer of 500- μm glass beads acted as the top layer. The top layer was 11.2 times more permeable than the bottom layer. No flow barrier existed between the layers. Fig. 1 shows the position of the polymer fronts in the bottom layer at the time when the polymer reached a fixed position in the top layer. The figure clearly shows the benefit of a polymer flood. As the viscosity of the injected fluid increases, sweep efficiency in the less-permeable layer increases. (Details of these experiments can be

found in Sorbie and Seright 1992. Videos of these laboratory experiments may be viewed at <http://baervan.nmt.edu/randy/>.)

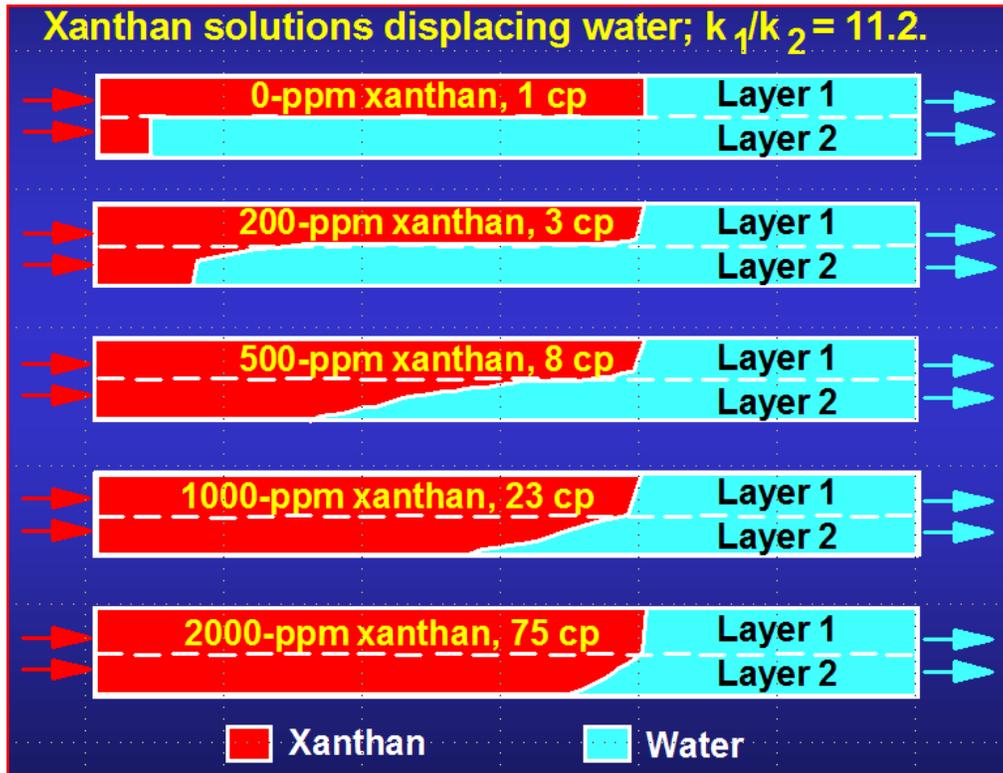


Fig. 1—Polymer flood improving sweep in a two-layer system with free crossflow.

Gels for In-Depth Profile Modification. When gels and other blocking agents were proposed to improve sweep in stratified reservoirs with crossflow, it was commonly stated or implied that the material exclusively entered and reduced permeability in high-permeability strata, thereby diverting subsequently injected water into less-permeable oil-bearing strata (Needham and Doe 1987, Chang *et al.* 2006, Choi *et al.* 2010). Unfortunately, this view ignores penetration into and permeability reductions in less-permeable strata (Seright 1988, Sorbie and Seright 1992, Sydansk and Romero-Zeron 2011). In Fig. 1, one can easily envision that if the polymer solution suddenly gelled, the reduction in flow capacity in the low-permeability layer may be greater than in the high-permeability layer. This expectation is confirmed experimentally in Fig. 2 and in additional videos of experiments at <http://baervan.nmt.edu/randy/>. After polymer placement, injected water forms severe viscous fingers that channel exclusively through the high-permeability layer.

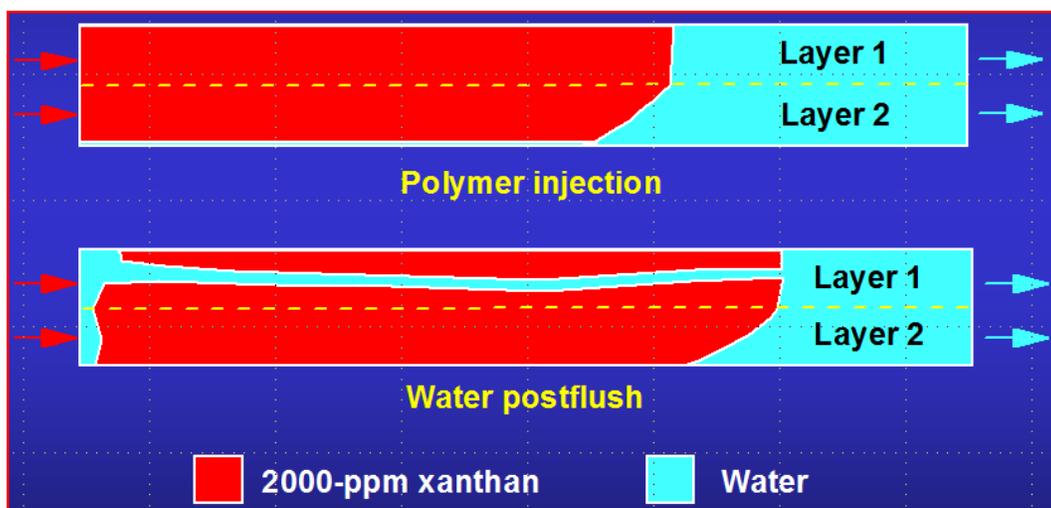


Fig. 2—Water injection following polymer injection for the bottom case in Fig. 1.

Water Postflush Following Placement of a Water-Like Gelant. To get around the problem illustrated in Fig. 2, an idea was conceived that used a water postflush following placement of a water-like gelant (Fletcher *et al.* 1991, Sorbie and Seright 1992). Fig. 3 illustrates the idea. During waterflood operations, assume that injected water has reached a production well by following a high-permeability pathway. Presumably, considerable mobile oil remains in less-permeable strata. For the first step of the gel treatment, a gelant with a water-like viscosity is injected (Fig. 3a). Because of the low viscosity of the gelant, penetration into the less-permeable zones is minimized (Seright 1988, Sorbie and Seright 1992). Second, water is injected to displace the water-like gelant away from the wellbore (Fig. 3b). Enough water must be injected so that the rear of the gelant bank in the most-permeable zone outruns the front of the gelant bank in an adjacent less-permeable zone. In the third step of the process, the gelation or permeability reduction occurs (Fig. 3c). Finally, if the gel treatment is applied in a waterflood injection well, water injection is resumed (Fig. 3d). Hopefully, a pathway will be available for water to crossflow from the high-permeability zone into the less-permeable zone(s) so that sweep efficiency can be improved.

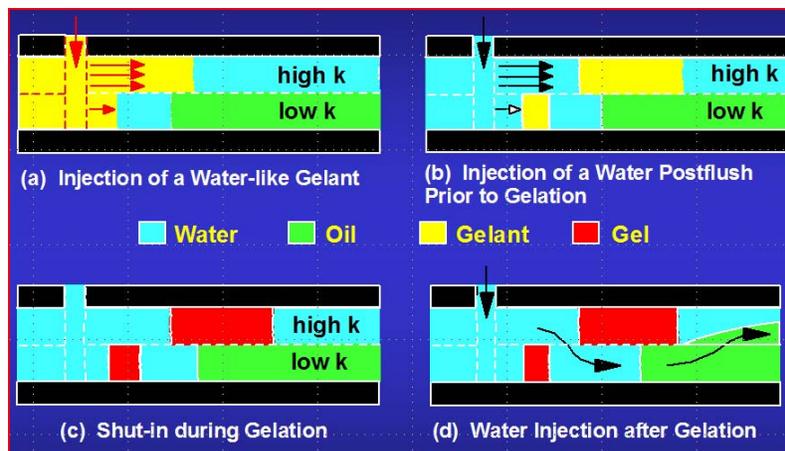


Fig. 3—Use of a water post-flush with a water-like gelant.

If this scheme is feasible, it could provide favorable injectivity. During water injection after gelation, much of the water leaving the wellbore should enter the most-permeable zone. If the cross-sectional area is relatively large in the region where water cross flows from the high-permeability zone into the low-permeability zone, injectivity losses from the gel treatment could be minimized. In contrast, conventional gel treatments (i.e., those with no postflush prior to gelation) in unfractured injection wells should cause significant injectivity losses. The “incremental” oil from this scheme could be recovered relatively quickly. Oil displaced from the less-permeable zones can crossflow into the most-permeable zone, where it can flow more rapidly to the production well.

A number of limitations should be recognized for this scheme. First, the gel treatment will not improve sweep efficiency beyond the greatest depth of gelant penetration in the reservoir. Once beyond the gel bank in the most-permeable zone, fluids can crossflow back into the high-permeability channel. This provides an incentive to maximize the depth of gelant penetration in the high-permeability channels.

Gelation time can be an important factor that limits the depth of gelant penetration in a reservoir. If the offending channel consists of a very permeable rock matrix, then very long gelation delays (many months) may be needed in order to achieve large depths of gelant penetration.

The applicability of this scheme depends on the sweep efficiency in the reservoir prior to the gel treatment. In injection wells, the scheme is expected to work best if sweep efficiency was very poor prior to the gel treatment. Then, the water that is diverted into the less-permeable strata should primarily displace oil. In contrast, if sweep efficiency was high prior to the gel treatment or if gelant penetration is insufficient in the high-permeability channel, there may be little or no oil to displace in the less-permeable zones.

In light-oil reservoirs, one very important limitation is that the viscosity and resistance factor of the gelant must not be too large. Viscous gelants will penetrate to a greater degree into the less-permeable zones (see Fig. 1). Furthermore, prior to gelation, viscous gelants will crossflow continuously from the high-permeability channel into the adjacent less-permeable zones. This creates a barrier of viscous gelant in the less-permeable zones all along the interface with the high-permeability channel. When a water postflush is injected, the barrier hinders crossflow of water from the high-permeability channel into the less-permeability zones. Thus, viscous fingers from a water postflush will break through the viscous gelant bank in the high-permeability channel before breakthrough in less-permeable zones. This can render the process ineffective. In viscous oil reservoirs, it is conceivable that this limitation could be relaxed. In addition, the viscosity and resistance factor of the gelant should not increase much during injection of either the gelant or the water postflush. Any increase in gelant resistance factor during this time will drive additional gelant into the less-permeable zones, and thereby, jeopardize the process.

Use of a Thermal Front. A variation of the idea in Fig. 3 is illustrated in Fig. 4. Cold water is sometimes injected into hot reservoirs, creating a thermal front that moves through the reservoir more slowly and evenly than the displacement front (Fletcher *et al.* 1991). If a gelant is injected that is activated by heat, a plug might form in the high-permeability layer after the formulation passes the thermal front (Fig. 4). With proper planning, no plug will form in the less-permeable layer because the gelant never reaches the thermal front (so the gelant never experiences a high enough temperature to react and form a gel). The reader should recognize that the scheme in Fig. 4 is subject to all the advantages and limitations that were mentioned above for Fig. 3. The concept in Fig. 4 was field tested in the Kuparuk field on the North Slope of Alaska in the early 1990s. Aluminum-crosslinked HPAM was the gelant (Pritchett *et al.* 2003). Although world-class engineering was used during project design and implementation, permeability reduction was felt to have been confined to the region of the injection well because of aluminum retention (Pritchett *et al.* 2003).

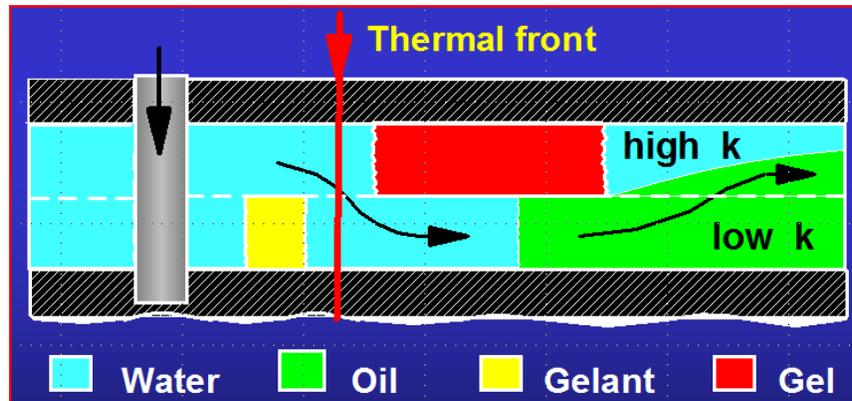


Fig. 4—Modified idea, exploiting a thermal front.

In recent years, a variation of the above concept has been commercialized (Chang *et al.* 2002, Frampton *et al.* 2004). We will refer to this as in-depth “popping” technology, because it uses polymer particles that “pop” or swell when activated. The material consists of crosslinked sulfonate-containing microparticles (0.1-3 μm in diameter) with both labile and stable internal crosslinks (Frampton *et al.* 2004). The kernel particles are manufactured as a 30% dispersion in light mineral oil. This dispersion is diluted along with a surfactant (surfactant/polymer ratio of 1:2 to 1:3) to prepare polymer concentrations from 3,000 ppm to 4,500 ppm (Pritchett *et al.* 2003, Ghaddab *et al.* 2010). Cost for the polymer was indicated to be \$5.71/lb in 2003 (Pritchett *et al.* 2003). The activation is typically accomplished by exposure to elevated temperature. Consequently, this technology has been advocated and applied in cases where cold water has been injected into a warm/hot reservoir—i.e., where a thermal front exists in the reservoir. The polymer particles are injected with the intention that they will pass the thermal front and “pop” first in the high-permeability watered-out zones, thus diverting subsequently injected water/fluids into the less-permeable oil zones. Resistance factors estimated for the “popped” polymer ranged from 11 to 350 (Frampton *et al.* 2004, Ohms *et al.* 2010, Husband *et al.* 2010). The reader should realize that from a reservoir engineering viewpoint, this concept has the same advantages/limitations as the postflush concept described in Fig. 3. Field applications of the process have occurred in Indonesia (Pritchett *et al.* 2003), Argentina (Yanez *et al.* 2007), Alaska (Ohms *et al.* 2010, Husband *et al.* 2010), and Tunisia (Ghaddab 2010). Ohms *et al.* (2010) reported injecting ~40,000 lbs of polymer (38,000 bbl with 3,300 ppm polymer), and recovering ~60,000 bbl of oil. Husband *et al.* (2010) reported injecting ~200,000 lbs of polymer (190,000 bbl with 3,000 ppm polymer) into three wells, and recovering ~500,000 bbl of oil.

METHODS AND ASSUMPTIONS

The question raised in this paper is: When is the above in-depth profile modification process a superior choice over conventional polymer flooding? We made several attempts to address this question using both analytical and simulation methods (Akanni 2010, Zhang 2010). This paper presents our most refined effort. All three of our efforts assumed that the in-depth popping material had the same viscosity as water prior to activation. This assumption is optimistic and will push our analysis results in favor of in-depth profile modification (compared with traditional polymer flooding). In reality, prior to activation, the popping material exhibits viscosities/resistance factors that are 2 to 7 times higher than water (Chang *et al.* 2002, Pritchett *et al.* 2003). As demonstrated in Fig. 1, increased viscosity promotes crossflow of the gelant into the less-permeable layers and diminishes or eliminates the ability of post-flush water to be diverted into the less-permeable layer (Fig. 2). For the in-depth profile-modification process, Sorbie and Seright (1992) suggested that the maximum allowable viscosity/resistance factor during placement is ~0.3 times the permeability contrast.

All three of our efforts assumed that the popping material caused no permeability reduction in the less-permeable zone. Again, this is an optimistic assumption that will favor in-depth profile modification over traditional polymer flooding. All of our efforts also assumed that (1) activation of the popping material occurred instantaneously, (2) permeability was reduced to zero in the high-permeability path where the popping material was activated, and (3) the permeability reduction was permanent. In reality, the popping material reduces permeability by factors from 11 to 350 (Frampton *et al.* 2004, Ohms *et al.*

2010, Husband *et al.* 2010). Also, the resistance associated with the popped polymer bank goes through a peak (with time and throughput) and shows some degree of movement through porous media (Chang *et al.* 2002, Frampton *et al.* 2004). This behavior is what might be expected. If the particles pop to become hydrated polymer molecules in solution, the resistance factors reflect the viscosity of 3,000-4,500-ppm polymer solutions. For a time, this viscous polymer bank in the high-permeability zone (hopefully) will allow much of the subsequently injected brine to be diverted into less-permeable zones. However, eventually, the brine will finger through this viscous polymer bank (as in Fig. 2). Thus, our assumption of a permanent block in the high-permeability layer is optimistic and will favor in-depth profile modification over traditional polymer flooding. Capillary pressure and gravity were also neglected during all of our efforts. Also, no dispersion was allowed at the boundaries of the popping-agent bank. Furthermore, in all our analyses, polymer rheology was Newtonian; polymer retention balanced inaccessible pore volume; and polymer did not reduce residual oil saturation below that for water flooding. Flow was generally linear between one injection well and one production well. (However, during the two simulation efforts, radial flow was assumed in the two well grid blocks.) The relative permeability characteristics that we used were:

$$k_{rw} = k_{rwo} [(S_w - S_{wr}) / (1 - S_{or} - S_{wr})]^{nw} \dots\dots\dots(1)$$

$$k_{ro} = k_{roo} [(1 - S_{or} - S_w) / (1 - S_{or} - S_{wr})]^{no} \dots\dots\dots(2)$$

$$k_{rwo} = 0.1, k_{roo} = 1, S_{or} = 0.3, S_{wr} = 0.3, nw = 2, no = 2 \dots\dots\dots(3)$$

Using the ECLIPSE simulator, Akanni (2010) examined a two-layer reservoir with permeability contrasts ranging from 2:1 to 20:1 and with oil/water viscosity ratios ranging from 1 to 10,000. He assumed relatively large popping-agent bank sizes and examined the effect of popping-agent bank positioning on recovery. He concluded that in-depth profile modification would have its greatest opportunity to compete with polymer flooding if the permeability contrast between layers was high. As expected, he concluded that placement of larger popping-agent banks in the high-permeability layer would enhance oil recovery, but economics would likely favor use of small popping-agent banks. He also concluded that higher recovery values favored positioning the popped bank in the middle of the high-permeability layer or somewhat towards the producer (i.e., not near the injector). Some concerns were raised about the simulations during the benchmarking process. Akanni (2010) was unable to match accepted expectations during waterflooding (i.e., prior to application of polymer flooding or in-depth profile modification). In particular, as the water/oil mobility ratio increases, accepted reservoir engineering predicts that recovery efficiency in a stratified reservoir should become progressively worse for the case of free crossflow than for the case of no crossflow (Craig 1971). Instead, the simulation predicted that waterflood recoveries for the crossflow and no-crossflow cases were similar, even at high mobility ratios. We presume that this deficiency was due to our inexperience with simulation (at the PRRC). However, we noted this same behavior with two other simulators (using other personnel).

Consequently, an effort was made to attack our problem using strictly analytical means (i.e., no simulator). In that analysis, Zhang (2010) confirmed that in-depth profile modification had the best opportunity to compete with polymer flooding when the permeability contrast between layers was high. In-depth profile modification also benefited when the high-permeability layer was much thinner than the less-permeable layer. The study also indicated that use of small popping-agent banks would be most desirable (economically) when displacing low-viscosity oils. More viscous oils are expected to require larger popping-agents banks.

For both of the previous approaches, at the start of polymer injection or popping-agent placement, we assumed that the high-permeability layer was at residual oil saturation and the low-permeability layer was at connate water saturation. We also assumed that the popping agent was placed instantaneously. Both of these assumptions are unrealistic. Consequently, a new analysis was performed by an expert in simulation of chemical flooding processes. This analysis assumed that (1) the reservoir was initially at connate water saturation, and (2) one pore volume (PV) of water was injected before beginning either polymer or popping-agent injection. For the in-depth profile-modification cases in the new analysis, the popping-agent material acted simply as a continued waterflood until the popping-agent bank reached its desired location. For example, if a small bank of popping agent was to be placed in the center of the high-permeability layer, (1) the reservoir (i.e., both layers) were at connate water saturation initially, (2) one PV of water was injected, (3) an additional amount of fluid (1-cp popping-agent pre-gel material followed by water) was injected to allow the popping-agent bank to reach the center 5% of the high-permeability layer, (4) the popping-agent bank was then instantaneously set into place to reduce permeability in the center 5% of the high-permeability layer to zero, and (5) finally, the waterflood was continued with the new block in place.

In order to verify the correctness of our previous efforts, we used a simulator from CMG. Our experienced simulation person was able to confirm credible behavior during benchmarking waterflood simulations. Subsequently, we examined oil recovery efficiency for the two processes (in-depth profile modification versus polymer flooding) as a function of (1) permeability contrast (up to 10 fold), (2) relative zone thickness, (3) oil viscosity (up to 1,000 cp), (4) polymer solution viscosity, (5) polymer or blocking-agent bank size, and (6) relative costs for polymer versus blocking agent. In Figs. 5-11, we plot the percent of original mobile oil in place that was recovered as a function of PV injected. Results from the first PV of injection were not included because they were all the same for a given figure (because 1 PV of water was injected at the start

of all cases). In each figure, the thin solid curve (with no symbols) represents the waterflood-only curve, and the thick solid curves represent the case where polymer solutions (10, 40, or 100 cp) were injected beginning after 1 PV of waterflood. The other three curves in each figure show cases where 5%, 35%, or 90% of the high-permeability layer (HP-PV) was blocked with popping-agent gel (after the initial waterflood).

Effect of Oil Viscosity

We first examine the effects of oil viscosity. Our initial interest in this topic was motivated by a question as to whether in-depth profile modification would be preferred over polymer flooding for reservoirs on Alaska's North Slope that contained somewhat viscous oils (100-1,000 cp). Figs. 5-7 show recovery projections (expressed as the percent of the original mobile oil that was in place) versus pore volumes injected for oil viscosities of 10 cp, 100 cp, and 1,000 cp, respectively. For each case in these figures, the high-permeability layer (Layer 1) was 10 times more permeable than the low-permeability layer ($k_1/k_2=10$), the low-permeability layer (Layer 2) was 9 times thicker than the high-permeability layer ($h_2/h_1=9$), and water viscosity was 1 cp. In all cases, waterflooding occurred between 0 and 1 PV—then the alternative process was implemented. In each of the following figures, the thin black curve shows the results for continued waterflooding, which provided the lowest recovery in all cases.

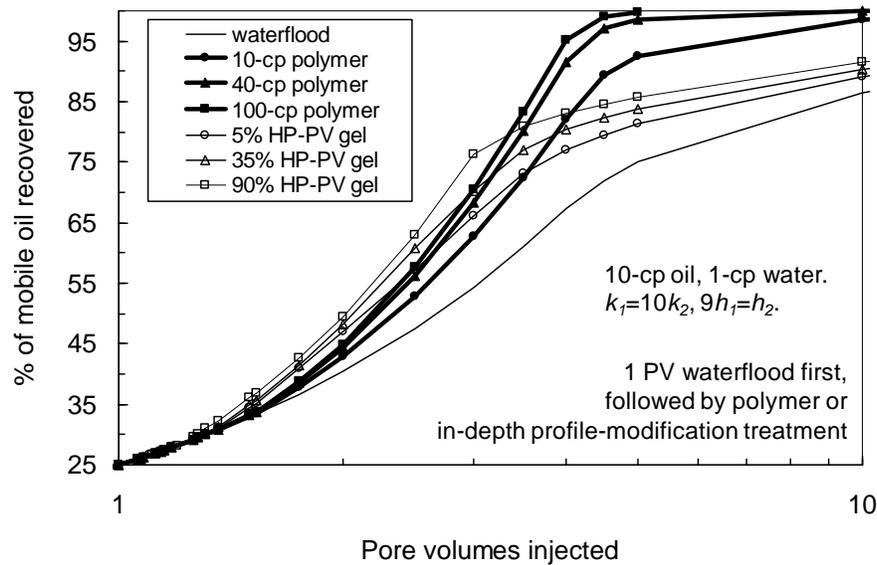


Fig. 5—Recovery with $k_1/k_2=10$ and $h_2/h_1=9$. 10-cp oil.

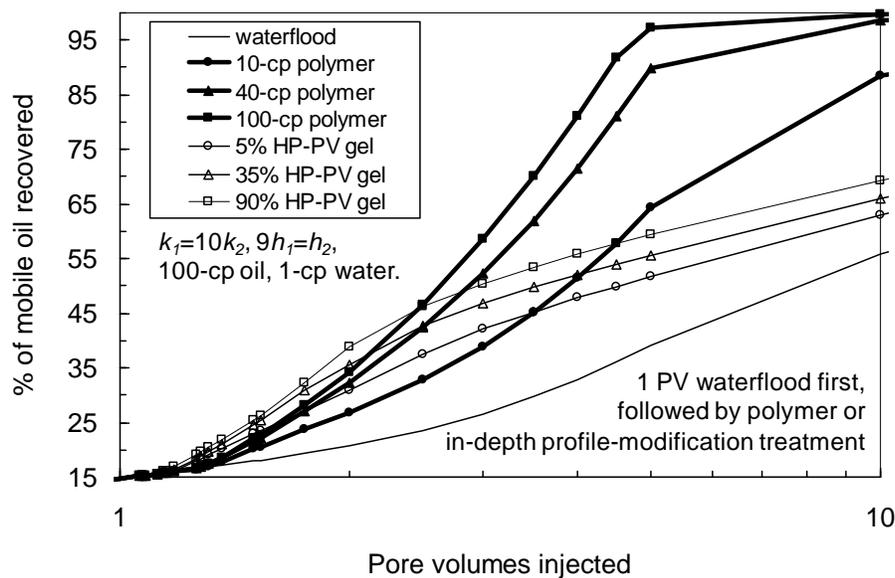


Fig. 6—Recovery with $k_1/k_2=10$ and $h_2/h_1=9$. 100-cp oil.

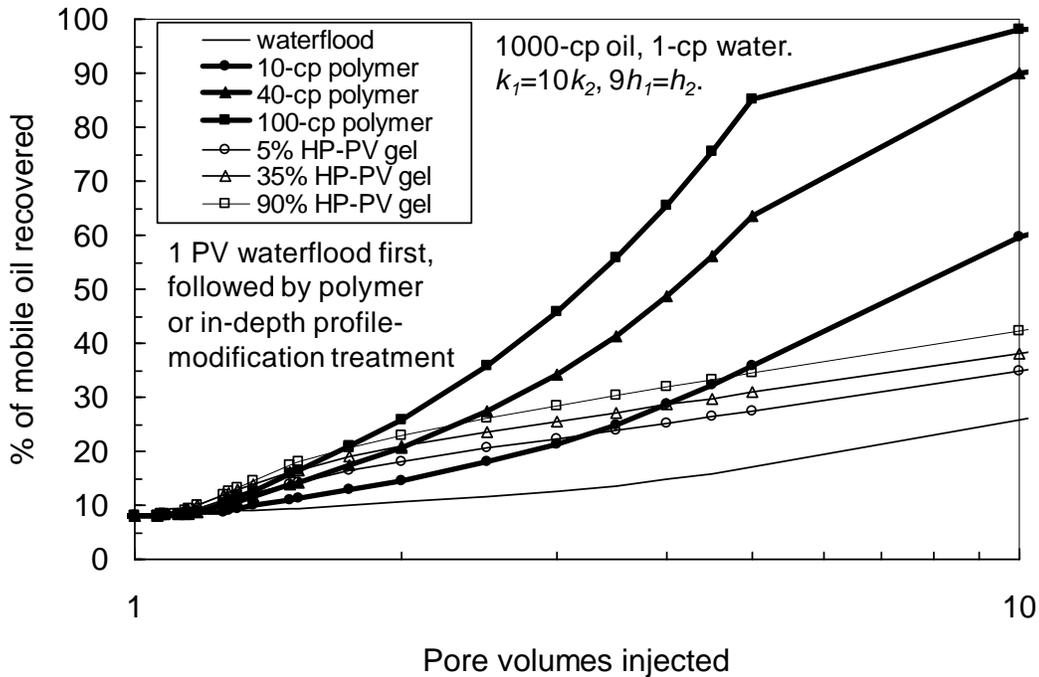


Fig. 7—Recovery with $k_1/k_2=10$ and $h_2/h_1=9$. 1,000-cp oil.

The thick black curves in Figs. 5-7 show results from polymer floods with 10-cp, 40-cp, or 100-cp polymer. These results are quite in-line with expectations (Seright 2010). When displacing 10-cp oil (Fig. 5), injecting a 10-cp polymer solution provides a noticeable improvement over waterflooding. Additional recovery is seen using 40-cp or 100-cp polymer, but the incremental benefit diminishes substantially with increased polymer viscosity. In contrast, for the 100-cp and 1,000-cp oils (Figs. 6 and 7), substantially greater recovery is seen with the more viscous polymer solutions.

In Figs. 5-7, the thin lines with open symbols show results for various bank sizes (5% to 90% in the high-permeability layer) for the in-depth profile-modification process. Interestingly, in all three figures, a 90% popping-agent bank only recovered modestly more oil than a 5% bank. There are several reasons for this. First, for the more viscous oils, during water injection after placement of the popping agent, sweep efficiency is poor in the thick less-permeable zone. Viscous fingering within the less-permeable layer strongly affects the incremental recovery. Second, because we assumed that permeability dropped to zero when the popping agent activated, oil reserves in the blocked portions of the high-permeability layer were lost. The magnitude of the loss is directly proportional to the size of the popping-agent bank. One can argue that this loss of reserves is unrealistically pessimistic, since water can actually viscous finger into the popping-agent bank and displace some of that trapped oil. However, this error is offset by our overly optimistic assumption that the blocking action is permanent in the high-permeability layer. As will be seen shortly, the relatively modest effect of popping-agent bank size on recovery will result in economics favoring the use of small banks. This observation is consistent with what is currently advocated by the vendor of this in-depth profile-modification technology.

Note that in-depth profile modification provides higher oil recovery values (for a given PV) than polymer flooding between 1 and 3 PV. Even for this PV range, the recovery values are, at best, only modestly greater than for polymer flooding. At high PV values (>4 PV), polymer flooding always provides higher recovery values.

Effect of Permeability Contrast

Along with Figs. 5-7, Figs. 8 and 9 demonstrate the effect of permeability contrast on the performance of in-depth profile modification versus polymer flooding. Permeability contrast was 10:1 in Fig. 6, 5:1 in Fig. 8, and 2:1 in Fig. 9. For all three cases, oil viscosity was 100 cp, and the low-permeability layer was nine times thicker than the high-permeability layer. A comparison of Figs. 6 and 8 reveals that the enhanced recovery using in-depth profile modification (over 10-cp polymer flooding) diminishes significantly as the permeability contrast drops from 10:1 to 5:1. Fig. 9 (2:1 permeability contrast) shows no benefit of in-depth profile modification over 10-cp polymer flooding, for any popping-agent bank size. These results are qualitatively consistent with the results from our earlier analytical effort (Zhang 2010) and with the results from the first simulation effort using ECLIPSE (Akanni 2010).

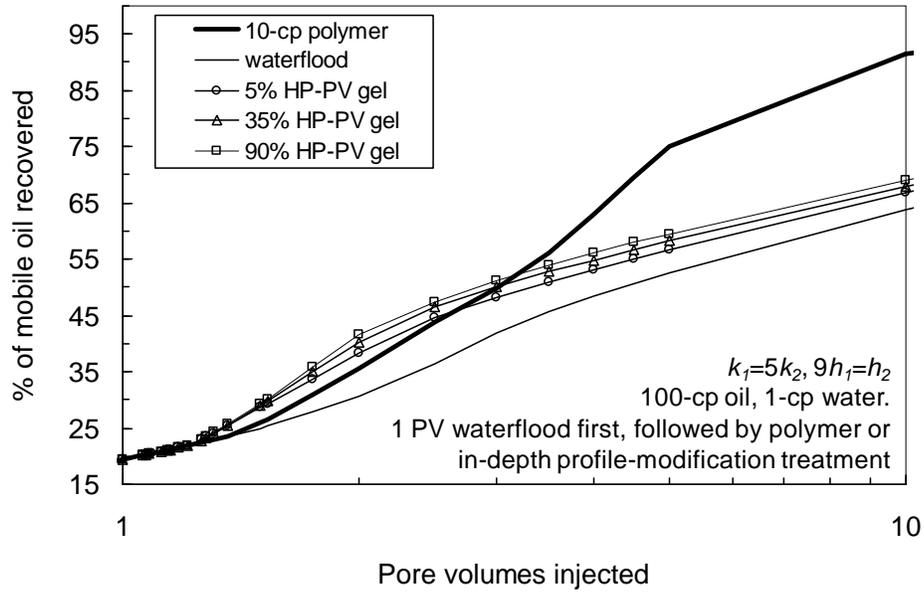


Fig. 8—Recovery with $k_1/k_2=5$ and $h_2/h_1=9$. 100-cp oil.

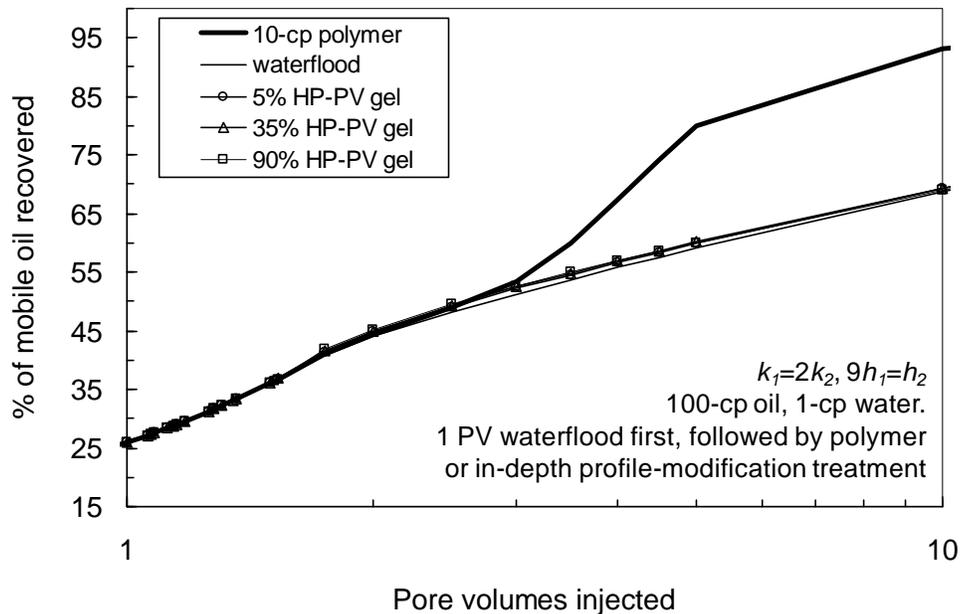


Fig. 9—Recovery with $k_1/k_2=2$ and $h_2/h_1=9$. 100-cp oil.

Effect of Layer Thickness

Along with Figs. 5-7, Figs. 10 and 11 demonstrate the effect of layer thickness on the performance of in-depth profile modification versus polymer flooding. The thickness ratio (low-permeability layer to high-permeability layer) was 9:1 in Fig. 6, 3:1 in Fig. 10, and 1:1 in Fig. 11. For all three cases, oil viscosity was 100 cp, and the high-permeability layer was ten times more permeable than the low-permeability layer. For large popping-agent bank sizes (e.g., 35% or 90%), in-depth profile modification showed enhanced recovery (over 10-cp polymer flooding) for thickness ratios of 9:1 and 3:1 (Figs. 6 and 10). However, the benefit occurred over a narrower range of PV for a 3:1 thickness ratio (1.3-2.5 PV in Fig. 10) than for a 9:1 thickness ratio (1.2-4 PV in Fig. 6). For a 1:1 thickness ratio, Fig. 11 shows that 10-cp polymer flooding was superior to in-depth profile modification. The results reveal that in-depth profile modification is most appropriate for high permeability contrast (e.g. 10:1) and high thickness ratios (e.g., less-permeable zones being 10 times thicker than high-permeability zones). These results are qualitatively consistent with the results from our earlier analytical effort (Zhang 2010).

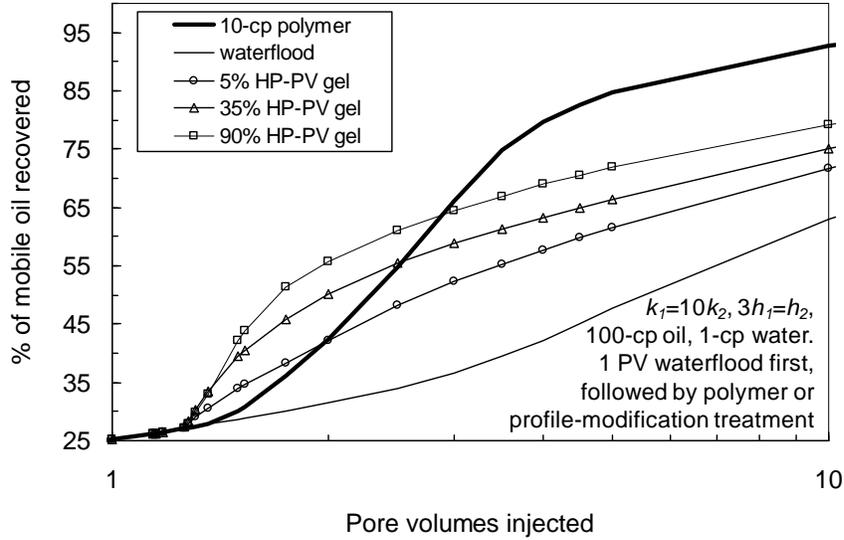


Fig. 10—Recovery with $k_1/k_2=10$ and $h_2/h_1=3$. 100-cp oil.

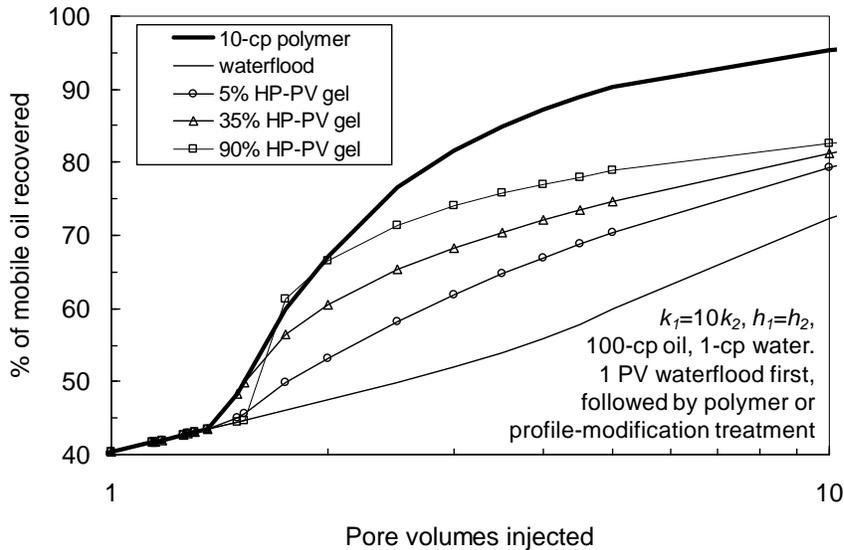


Fig. 11—Recovery with $k_1/k_2=10$ and $h_2/h_1=1$. 100-cp oil.

Cost Considerations

The popping-agent process usually uses high concentrations of polymers (e.g., 0.3%-0.45%) and surfactants (e.g., 0.1%-0.2%), resulting in a cost (per weight of chemical) that is several times higher than for conventional polymer flooding (Pritchett *et al.* 2003, Ghaddab *et al.* 2010). The polymer used in the popping-agent process (an internally crosslinked HPAM) is a specialty polymer and therefore more expensive (on a per weight basis) than HPAM. In the following analysis, we will focus on the most-favorable case for in-depth profile modification, with a permeability contrast (k_1/k_2) of 10:1 and a thickness ratio (h_2/h_1) of 9:1. Oil was assumed to have a value of \$50/bbl; water was assumed to cost \$0.25/bbl; HPAM was assumed to cost \$1.50/lb; a 10-cp HPAM solution required 0.1% polymer; a 40-cp HPAM solution required 0.2% polymer; a 100-cp HPAM solution required 0.3% polymer; and the popping-agent block was assumed to require 0.3% concentration of popping-agent polymer. Our assumptions about viscosity versus HPAM concentration are conservative in favor of the in-depth profile-modification process. This level of viscosification by HPAM would be valid if the injection water was saline (e.g., as in seawater). If less saline water were used, a higher viscosity would be achieved with less polymer. For example, at Daqing, 0.1% HPAM yields solution viscosities from 20 to 50 cp (Wang *et al.* 2008b). For a given PV of fluid injected, a relative profit was calculated as the total value of the oil produced minus the total cost of fluid injected (water, polymer, popping-agent material). In these figures, we assumed that the cost of the popping-agent material was expended immediately at the start of popping-agent injection—explaining the sudden drop in relative profit at 1 PV for the popping-agent cases.

The cost comparisons are shown in Figs. 12-14. These figures assume that the popping-agent material costs \$5.71/lb (per Pritchett *et al.* 2003) and 0.3% popping polymer was used in the popping bank. For an oil viscosity of 10 cp (Fig. 12), small popping-agent treatments appeared modestly more profitable than polymer flooding in the range from 2-4 PV. Note that the smallest popping-agent bank was always more profitable than the larger banks. Although large popping-agent banks result in higher oil recoveries (Figs. 5-7), their high cost negates that benefit (open triangles in Fig. 12). This result is consistent with the current advocacy of the popping-agent vendor. A table in the center of Fig. 12 compares the percent of the original mobile oil that was recovered after 5 PV for various cases. Note that the ultimate recoveries for polymer flooding were higher than for in-depth profile modification. Although the smallest popping-agent bank (5% of the PV in the high-permeability layer) provided a higher profitability (i.e., at 3 PV), its ultimate recovery factor was significantly less than for 10-cp polymer flooding. Also note that 10-cp polymer flooding provided a higher profitability than any of the other cases at 5 PV—where the profitability peak occurred. After 5 PV, profitability for polymer flooding decreased because the value of the oil produced was less than the value of the polymer injected. For the popping-agent cases, profitability did not decrease after 5 PV because no additional popping-agent material was purchased or injected. As mentioned earlier, this projection is overly optimistic because the blocking effect from the popping material will deteriorate with time (Chang *et al.* 2002, Frampton *et al.* 2004).

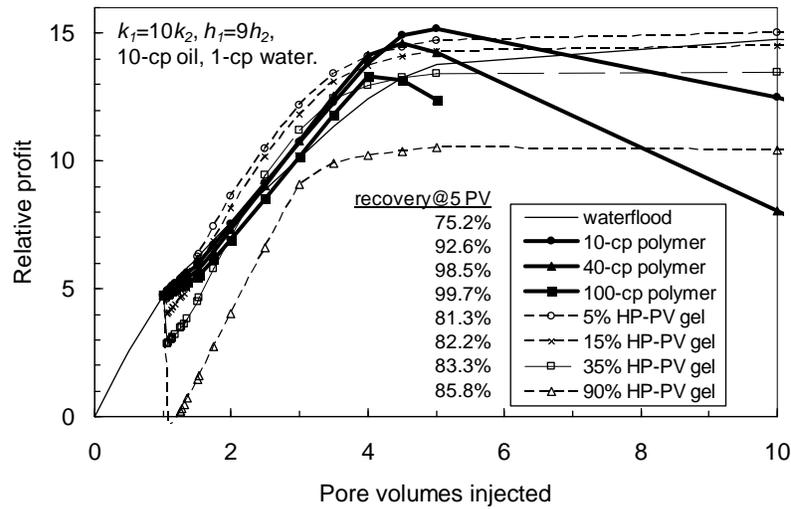


Fig. 12—Relative profit for various cases: 10-cp oil.

For 100-cp oil (Fig. 13), the economics for a 5% PV popping-agent treatment appears very slightly better than for a 40-cp polymer flood for a short range between 1 and 2.5 PV. However, recovery efficiencies are dramatically lower for the popping agent treatment (51.8% versus 89.8% in the center table of Fig. 13). For 1,000-cp oil, a 40-cp polymer solution appears superior to in-depth profile modification for virtually all cases (Fig. 14).

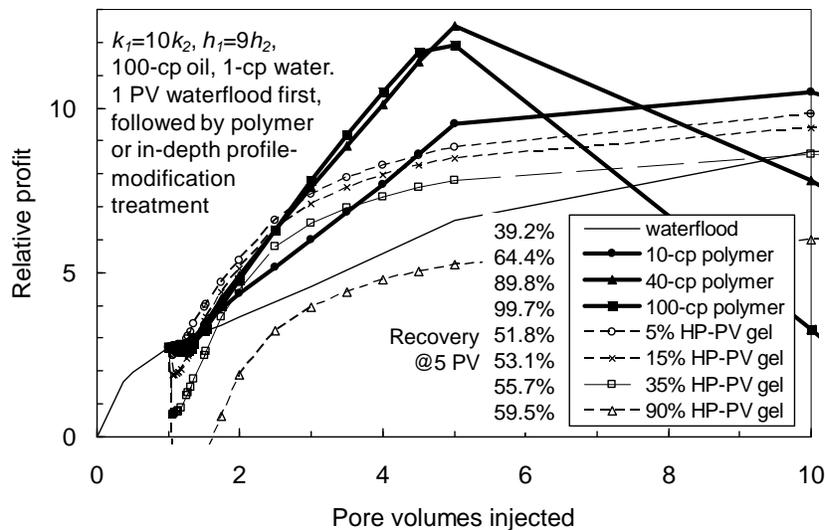


Fig. 13—Relative profit for various cases: 100-cp oil.

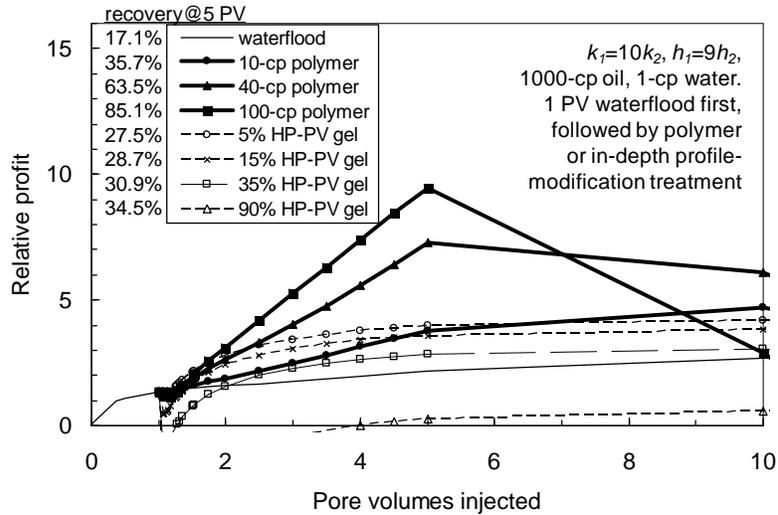


Fig. 14—Relative profit for various cases: 1000-cp oil.

Fig. 15 compares cases where the popping-agent material costs differing amounts. In all cases, Layer 1 was 10 times more permeable and 9 times thinner than Layer 2, and oil viscosity was 10-cp. For the cases with in-depth profile modification, the bank size was 5% PV (in the high-permeability layer). The “x” symbols with the dashed curve (labeled “1X cost”) shows the case where the popping-agent concentration was 0.3% and the popping-agent cost was \$5.71/lb. The “1.5X cost” case in Fig. 15 assumes that the total popping-agent cost was 1.5 times more expensive (e.g., as in Pritchett *et al.* 2003, where 0.45% popping-agent concentration was used). The “0.5X cost” case in Fig. 15 assumes that the total popping-agent cost was half as expensive (e.g., if a breakthrough in price reduction can be accomplished). All other assumptions were the same as in Fig. 12, with a small popping-agent bank (5% of the PV in the high-permeability layer). The primary message from Fig. 15 is that popping-agent performance was not highly sensitive to popping-agent cost, presumably because the bank size was so small. However, even though short-term economics (i.e., before 4 PV in Fig. 15) may favor small in-depth profile modification, a longer view (i.e., at 5 PV where the peak of profitability occurred) favored polymer flooding. Also, the relative simplicity of the polymer flooding process favors it over in-depth profile modification.

During a personal communication with R.H. Lane (June 16, 2011), we learned that Seyidov and Lane (2010) performed a relevant simulation study of “deep diverting gels.” This study assumed that the blocking agent could be effectively placed in a multilayered reservoir with crossflow. They observed a number of results that were consistent with our findings. Their study concluded that “although higher ultimate recovery was achieved with a polymer flood, the combination of delayed production response and large polymer amounts used adversely impacted polymer flood economics.” They also found that treatment size and oil viscosity were important variables in determining the effectiveness of these treatments.

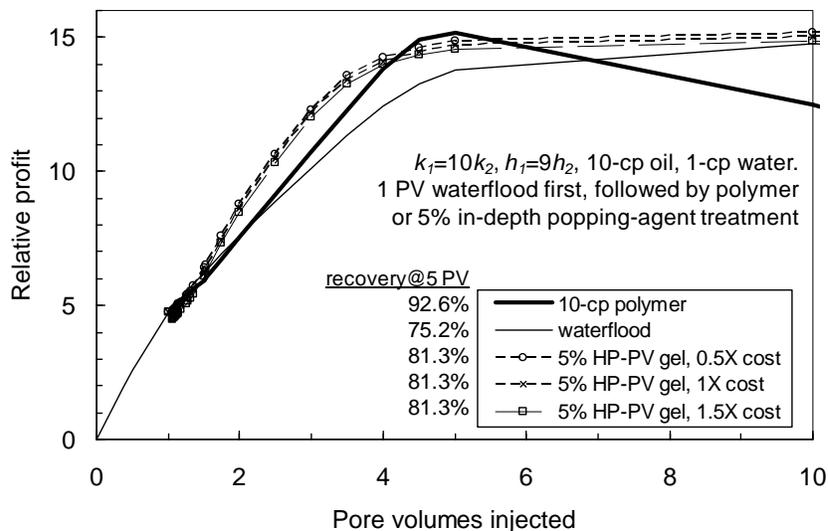


Fig. 15—Relative profit assuming various popping-agent material costs.

Injectivity Considerations

Concern about injectivity losses was a key motivation that was given for choosing in-depth profile modification over polymer flooding. The concern is that injectivity losses associated with injection of viscous polymer solutions will result in prohibitive losses in oil production rate. However, most waterflood and polymer flood injectors are thought to be fractured (Van den Hoek *et al.* 2009, Khodaverdian *et al.* 2009, Wang *et al.* 2008a, Seright *et al.* 2009). Fractures are especially likely to be present in hot reservoirs with cold-water injectors (Fletcher *et al.* 1991). Even when injecting concentrated, viscous polymer solutions (i.e., 200-300 cp), injectivity has not been a problem in field applications (Wang *et al.* 2011) because fractures extend to accommodate the viscosity and rate of fluid injected. Of course, the key concerns when injecting above the parting pressure are to not allow fractures to (1) extend so far and in a direction that causes severe channeling and (2) extend out of zone. If these concerns can be mitigated, under the proper circumstances, injection above the parting pressure can significantly (1) increase polymer solution injectivity and fluid throughput for the reservoir pattern, (2) reduce the risk of mechanical degradation for polyacrylamide solutions, and (3) increase pattern sweep efficiency (Trantham *et al.* 1980, Wang *et al.* 2008a, Seright *et al.* 2009). Using both field data and theoretical analyses, these facts have been demonstrated at the Daqing Oilfield in China, where the world's largest polymer flood is in operation (Wang *et al.* 2008a).

Additional Considerations

If small banks of popping-agent are injected (e.g., ~5% PV in the high-permeability layer), a significant amount of mixing and dispersion may occur as that bank is placed deep within the reservoir (Lake 1989)—thus, diluting the bank and potentially compromising the effectiveness of the blocking agent. Also, as mentioned earlier, since the popping material provides a limited permeability reduction (i.e., 11 to 350) and the popped-material has some mobility, the blocking bank eventually will be diluted and compromised by viscous fingering (Chang *et al.* 2002, Frampton *et al.* 2004).

Another consideration is the possibility of re-treatment for the in-depth profile-modification process. During a second or subsequent treatment, the presence of a block or partial block in the high-permeability layer will (1) divert new popping-agent into less-permeable zones during the placement process and (2) inhibit placement of a new block that is located deeper in the reservoir than the first block. These factors may compromise any re-treatment using in-depth profile modification.

A third additional consideration concerns the initial diagnosis of the problem. The assumption in this paper and with some of the previous treatments is that fractures or fracture-like features were not responsible for significant channeling in the reservoir. However, if the mobility ratio is favorable during waterflooding (i.e., low viscosity oil) and the maximum permeability contrast is modest (e.g., 4:1), one has to wonder why the water/oil ratio is high (e.g., <20) if the oil recovery factor is low. For this type of case, one may want to reconsider whether fractures are important to channeling. If so, traditional gel treatments (Sydansk and Romero-Zeron 2011) may warrant consideration.

Conclusions

Our analyses revealed that in-depth profile modification is most appropriate for high permeability contrasts (e.g. 10:1), high thickness ratios (e.g., less-permeable zones being 10 times thicker than high-permeability zones), and relatively low oil viscosities. Because of the high cost of the blocking agent (relative to conventional polymers), economics favor small blocking-agent bank sizes (e.g. 5% of the pore volume in the high-permeability layer). Even though short-term economics may favor in-depth profile modification, ultimate recovery may be considerably less than from a traditional polymer flood. A longer view may favor polymer flooding both from a recovery viewpoint and an economic viewpoint.

Acknowledgements

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Nomenclature

- h_1 = height of Layer 1, ft [m]
- h_2 = height of Layer 2, ft [m]
- k_{ro} = relative permeability to oil
- k_{roo} = endpoint relative permeability to oil
- k_{rw} = relative permeability to water
- k_{rwo} = endpoint relative permeability to water
- k_1 = permeability of Layer 1, mD [μm^2]
- k_2 = permeability of Layer 2, mD [μm^2]
- no = oil saturation exponent in Eq. 2
- nw = water saturation exponent in Eq. 1
- PV = pore volumes of fluid injected
- S_{or} = residual oil saturation
- S_w = water saturation
- S_{wr} = residual water saturation

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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