

# Potential for Polymer Flooding Reservoirs With Viscous Oils

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## Summary

This paper examines the potential of polymer flooding to recover viscous oils, especially in reservoirs that preclude the application of thermal methods. A reconsideration of enhanced-oil-recovery (EOR) screening criteria revealed that higher oil prices, modest polymer prices, increased use of horizontal wells, and controlled injection above the formation parting pressure all help considerably to extend the applicability of polymer flooding in reservoirs with viscous oils. Fractional-flow calculations demonstrated that the high mobile-oil saturation, degree of heterogeneity, and relatively free potential for crossflow in our target North Slope reservoirs also promote the potential for polymer flooding. For existing EOR polymers, viscosity increases roughly with the square of polymer concentration—a fact that aids the economics for polymer flooding of viscous oils. A simple benefit analysis suggested that reduced injectivity may be a greater limitation for polymer flooding of viscous oils than the cost of chemicals. For practical conditions during polymer floods, the vertical sweep efficiency using shear-thinning fluids is not expected to be dramatically different from that for Newtonian or shear-thickening fluids. The overall viscosity (resistance factor) of the polymer solution is of far greater relevance than the rheology.

## Introduction

The objective of this work is to examine whether polymer flooding can provide a feasible means to recover viscous oils from reservoirs where thermal methods may not be applied. First, the screening criteria for application of polymer flooding are reconsidered. Next, fractional-flow calculations are used to illustrate improvements in displacement efficiency that can be achieved by polymer flooding of viscous oils. A simple benefit analysis is provided to compare polymer flooding with waterflooding. Permeability reduction and its variation with permeability are considered. Finally, the impact of polymer-solution rheology (especially shear thinning) on vertical sweep is discussed.

## Reconsideration of Screening Criteria for Polymer Flooding

Alaska's North Slope contains a very large unconventional oil resource—more than 20 billion bbl of heavy/viscous oil (Stryker et al. 1995, Thomas et al. 2007). Conventional wisdom argues that thermal recovery methods are most appropriate for recovering viscous oils (Taber et al. 1997a, 1997b). However, for viscous-oil reservoirs on Alaska's North Slope, a number of factors complicate this thinking. The formations that hold vast viscous-oil reserves—Ugnu, West Sak, and Schrader Bluff—are relatively close to permafrost. Steam generation is prohibitive here because of severe cold weather on the surface, heat losses while pumping steam down through 700 to 2,200 ft of permafrost, and heat losses when contacting the cold formation. There are also environmental considerations [air- and water-quality issues and disturbance of wildlife species; see Thomas et al. (2007)].

Kumar et al. (2008) examined waterflood performance using unfavorable mobility ratios. They concluded that viscous fingers

dominate high-viscosity-ratio floods, that mobile water can reduce oil recovery significantly, and that reservoir heterogeneity and thief zones accentuate poor displacement performance. Their paper strongly suggested that any improvement in mobility ratio (e.g., polymer flooding) can improve reservoir sweep and recovery efficiency noticeably.

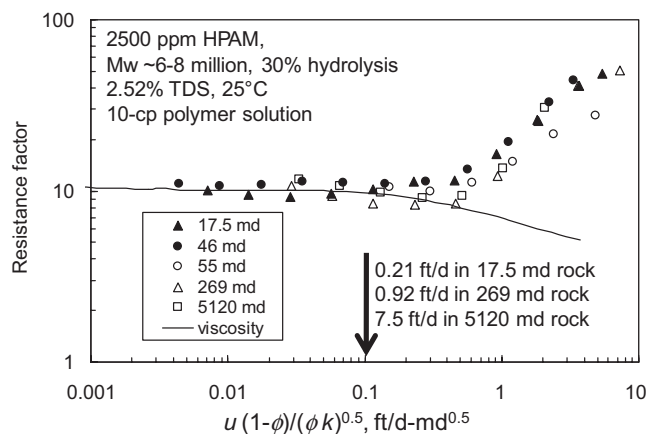
Beliveau (2009) reviewed waterfloods in viscous-oil reservoirs and concluded that estimated ultimate recoveries could reach 20–40% of original oil in place (OOIP) under appropriate circumstances. He noted that normally, 50% or more of the oil would be recovered at high water cuts (>90%).

Earlier screening criteria indicated that polymer flooding should be applied in reservoirs with oil viscosities between 10 and 150 cp (Taber et al. 1997a, 1997b). Two key factors were responsible for this recommended range. First, considering oil prices ( $\approx$ USD 20/bbl) and polymer prices [ $\approx$ USD 2/lbm for moderate molecular weight,  $M_w$ , polyacrylamide, or hydrolyzed polyacrylamide (HPAM) polymers] at the time, 150 cp was viewed as the most-viscous oil that could be recovered economically using polymer flooding. (For oil viscosities below 10 cp, the mobility ratio during waterflooding was generally viewed as sufficiently favorable that use of polymer would generally not be needed to achieve an efficient reservoir sweep.) Second, for oil viscosities greater than 150 cp, the viscosity requirements to achieve a favorable mobility ratio were expected to reduce polymer-solution injectivity to prohibitively low values (i.e., slow fluid throughput in the reservoir to the point that oil-production rate would be uneconomically low).

Several important changes have occurred since the previous screening criteria were proposed. First, oil prices increased to  $\approx$  USD 70/bbl, while polymer prices remained relatively low (USD 0.90 to 2.00/lbm for HPAM). Second, viscosification abilities for commercial polymers have increased, partly from achieving higher polymer molecular weights and partly from incorporating specialty monomers [e.g., with associating groups; Buchgraber et al. (2009)] within the polymers. Conventional wisdom from earlier polymer floods was that it was highly desirable to achieve a mobility ratio of unity or less (Maitin 1992). However, with current high oil prices, operators are wondering whether improved sweep from polymer injection might be economically attractive even if a unit mobility ratio is not achieved.

In wells that are not fractured, injection of viscous polymer solutions will necessarily decrease injectivity. In order to maintain the waterflood injection rates, the selected polymer-injection wells must allow higher injection pressures. Another important change since the time when earlier screening criteria for polymer flooding were developed (Taber et al. 1997a, 1997b) has been the dramatic increase in the use of horizontal wells. Use of horizontal wells significantly reduces the injectivity restrictions associated with vertical wells, and injector/producer pairs of horizontal wells can improve areal sweep and reduce polymer use requirements (Taber and Seright 1992).

Open fractures (either natural or induced) also have a substantial impact on polymer flooding. Waterflooding occurs mostly under induced-fracturing conditions (Van den Hoek et al. 2009). Particularly, in low-mobility reservoirs, large fractures may be induced during the field life. Because polymer solutions are more viscous than water, injection at pressures greater than the formation-parting pressure will be even more likely during a polymer flood than during a waterflood. The viscoelastic nature (apparent shear-thickening or "pseudodilatancy") of synthetic EOR polymers (e.g., HPAM) makes injection at pressures greater than the formation-parting pressure even more likely (Seright 1983; Wang et al. 2008a; Seright et al. 2009c).



**Fig. 1—HPAM resistance factors are Newtonian under our anticipated conditions.**

Under the proper circumstances, injection at pressures greater than 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. 2009c). Using both field data and theoretical analyses, these facts have been demonstrated at the Daqing oil field in China, where the world's largest polymer flood is in operation (Wang et al. 2008a). Khodaverdian et al. (2009) examined fracture growth during polymer injection into unconsolidated-sand formations.

During analysis of polymer flooding in this work, we assume that injectivity limitations will require that horizontal wells be used or that polymer injection occur at pressures greater than the fracture or formation-parting pressure. Consequently, linear flow will occur for most of our intended applications.

### Polymer-Flooding Considerations

Many factors are important during polymer flooding (Sorbie 1991; Wang et al. 2008b). During design of a polymer flood, critical reservoir factors that traditionally receive consideration are the reservoir lithology, stratigraphy, important heterogeneities (such as fractures), distribution of remaining oil, well pattern, and well distance. Critical polymer properties include cost effectiveness (e.g., cost per unit of viscosity), resistance to degradation (mechanical/shear, oxidative, thermal, microbial), tolerance of reservoir salinity and hardness, retention by rock, inaccessible pore volume, permeability dependence of performance, rheology, and compatibility with other chemicals that might be used. Issues long recognized as important for polymer-bank design include bank size (volume), polymer concentration and salinity (affecting bank viscosity and mobility), and whether (and how) to grade polymer concentrations in the chase water. For brevity, only a few of these factors will be addressed in this paper.

**Rheology.** Rheology in porous media is commonly raised as an issue during discussion of polymer flooding (AlSofi and Blunt 2009; Lee et al. 2009; Seright et al. 2009c). However, concern about polymer rheology must be tempered in view of injectivity realities. Achieving economic injectivities and fluid throughputs with polymer solutions (especially when displacing viscous oil) requires the use of either horizontal wells or fractured vertical wells (Seright 2009b, 2009c). With vertical fractures in vertical wells, fluid flows linearly away from the fracture. For horizontal wells, flow will be radial for a short time but soon becomes linear. For both horizontal wells and fractured vertical wells, the fluid flux will be quite low as the polymer enters the porous rock. For our target North Slope fields, we estimated flux values to be 0.01 to 0.2 ft/D for a vertically fractured injector, 0.2 ft/D as the fluid first enters the formation from a horizontal well, and 0.01 ft/D for most of the distance between two parallel horizontal wells. For this range of flux values, HPAM polymer solutions show Newtonian

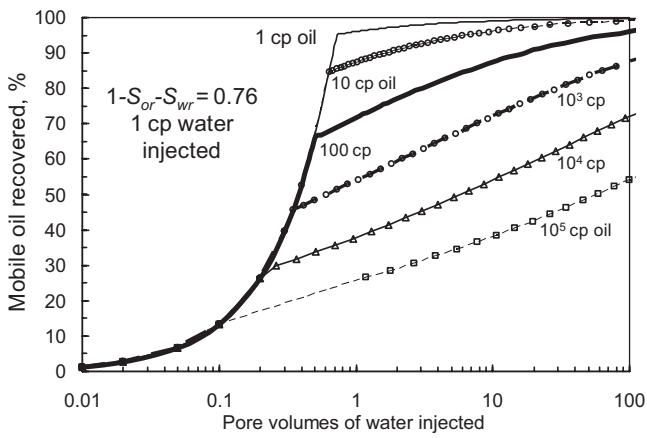
or near-Newtonian behavior (Seright et al. 2009c, 2010). **Fig. 1** illustrates this point for an HPAM polymer (6 to 8 million daltons) in cores with permeabilities ranging from 17.5 to 5,120 md. The *x*-axis plots a parameter that allows flux values (*u*, in ft/D) to be correlated for different permeabilities (*k*) and porosities (*φ*). The large arrow provides a point of comparison for different permeabilities. Over the practical range of permeabilities and velocities anticipated for our target fractured or horizontal wells (0.01 to 0.2 ft/D), HPAM polymer solutions (in representative North Slope brines at the target reservoir temperature) exhibit nearly constant resistance factors (effective viscosity in porous rock relative to water) (Seright 2009b; Seright et al. 2009c, 2010). These observations simplify our analysis of the potential for polymer flooding using HPAM. (Discussion of a strongly shear-thinning fluid, such as xanthan, will be included later.)

**Permeability Dependence of Resistance Factors.** Many studies (Chauveteau 1982; Cannella et al. 1988; Seright 1991) showed that resistance factor correlated quite well using the parameter  $u(1-\phi)/(\phi k)^{0.5}$ , where *u* is flux (in ft/D), *φ* is porosity, and *k* is permeability (in md). This effect is also demonstrated in Fig. 1. Beyond this rheological effect, polymers of a given type and molecular weight are known to exhibit a permeability below which they experience difficulty in propagating through porous rock (Jenning et al. 1971; Vela et al. 1976; Zhang and Seright 2007; Wang et al. 2008b, 2009). As permeability decreases below this critical value, resistance factors, residual resistance factors, and polymer retention increase dramatically. As recommended by Wang et al. (2008b, 2009), we assume that the molecular weight and size of the chosen polymer are small enough so that the polymer will propagate effectively through all permeabilities and layers of interest—so this internal pore-plugging effect does not occur. A later section, “Practical Impact of Permeability Reduction and Its Variation With Permeability,” will consider the effect of different resistance factors in different layers.

**Gravity.** For the viscous crudes that we target, the density difference ( $\Delta\rho$ ) between water and oil is relatively small (12–23°API oil with 0.986- to 0.916-g/cm<sup>3</sup> oil density, with perhaps  $\Delta\rho=0.05$  g/cm<sup>3</sup> being typical between oil and water). An estimate of the vertical flux of a polymer front can be made using the gravity portion of the Darcy equation. Assuming a density difference of 0.05 g/cm<sup>3</sup>, a reservoir permeability of 100 md, and injection of a 10-cp polymer solution, the vertical migration of the polymer front caused by gravity will be only approximately 6 in./year (Seright 2009b). Consequently, gravity effects will be neglected in our subsequent considerations and calculations. Our work also assumes incompressible and isothermal conditions.

**Reduction of Residual-Oil Saturation.** Some reports indicate that polymer solutions can reduce the residual oil saturation ( $S_{or}$ ) below values expected for extensive waterflooding, and thereby increase the relative permeability to water (Wu et al. 2007; Huh and Pope 2008). Although we are currently experimentally exploring this issue for North Slope oil and conditions, this paper will assume that the same  $S_{or}$  value would ultimately be attained with either waterflooding or polymer flooding.

**Simulation vs. Fractional-Flow Calculations.** Simulation studies of polymer flooding are valuable in that complex reservoir configurations and combined effects of multiple physical, chemical, and fluid phenomena can be examined. Of course, inappropriate assumptions can lead to unrealistic predictions. Unfortunately, if a commercial simulator is used by someone who is not intimately familiar with the assumptions or defaults that are inherent in the software, flaws in the output may not be readily apparent. Three examples are mentioned here that have been witnessed recently. First, if the simulator incorrectly assumes shear-thinning behavior for an HPAM polymer, an overly optimistic injectivity will be predicted (Seright et al. 2009c). Second, if crossflow is not initiated properly in the simulator, recovery values can be incorrectly predicted to be similar to no-crossflow cases, even though the mobility ratio is nowhere near unity (Seright 2009b). Third, an



**Fig. 2—Fractional-flow calculations for water displacing oil, one layer, North Slope case.**

unconventional definition of inaccessible pore volume can lead one to enter a grossly inappropriate value (Dawson and Lantz 1972).

As an alternative to simulation, fractional-flow analysis was used by several authors to quantify polymer-flood performance (Lake 1989; Sorbie 1991; Green and Willhite 1998). This type of analysis has the advantage of being sufficiently transparent to readily determine whether the projections are realistic. Fractional-flow analysis will be used in this paper. After we establish credible behavior for simple systems, the results can be used as benchmarks for future, more-complex calculations using simulation.

**Water Displacing Oil**

**One Homogeneous Layer.** Our fractional-flow analyses assumed incompressible flow and no density or capillary pressure differences between phases. The relative permeability characteristics were given by Eqs. 1 and 2. The conditions given in Eq. 3 will be labeled our “base case,” while those in Eq. 4 will be our “North Slope case.” ConocoPhillips provided relative permeability characteristics that were representative of those in their viscous-oil, North Slope reservoirs.

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

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

**Base Case.**

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

**North Slope Case.**

$$k_{rwo} = 0.1, k_{roo} = 1, S_{or} = 0.12, S_{wr} = 0.12, nw = 4, no = 2.5. \dots \dots \dots (4)$$

For the North Slope parameters and a single layer with linear flow, the y-axis in Fig. 2 plots the percent of the mobile oil that was recovered for a given pore volume (PV) of water injected. (The total mobile oil is given by the difference between the original oil saturation at the connate-water saturation  $S_{wr}$  and the residual-oil saturation.)

**Two Layers With/Without Crossflow.** For the next set of cases, we considered linear displacement through two layers (of equal thickness), where  $k_1=1$  darcy,  $\phi_1=0.3$ ,  $k_2=0.1$  darcy,  $\phi_2=0.3$ . All other parameters and conditions were the same as those used in the one-layer case. We considered two subsets—one with no crossflow between the two layers and one with free crossflow (i.e., vertical equilibrium) between the layers. For the two-layer cases, we solved the fractional-flow calculations using spreadsheets. The two-layer no-crossflow case was straightforward because the displacements in the individual layers can be treated separately and then combined to yield the overall displacement efficiency (Green and Willhite 1998). The free-crossflow case required application of vertical equilibrium between the layers (Zapata and Lake 1981; Lake 1989). Examples of these spreadsheets can be found in Seright (2009a).

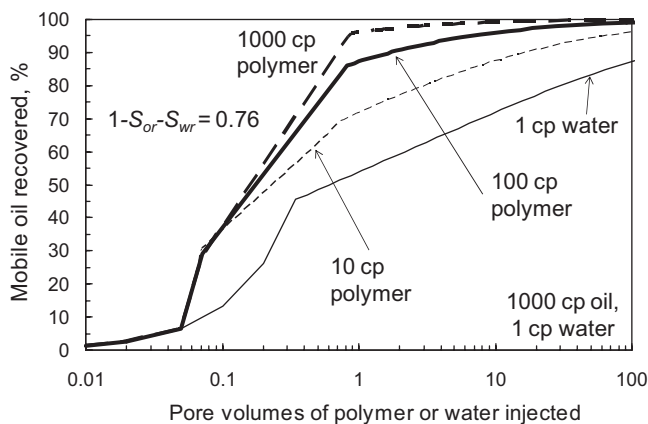
On the basis of the fractional-flow calculations for various crossflow and no-crossflow cases, Table 1 lists the recovery values at 1 PV of water injection, for relative permeabilities associated with both our base case and the North Slope case. Along with Fig. 2, this table hints at the potential for polymer flooding. For any given oil viscosity (e.g., 1,000 cp), one can envision that a tenfold decrease in the oil/water viscosity ratio (i.e., injecting a 10-cp polymer solution instead of water) could increase oil recovery by a substantial percentage.

Accepted reservoir-engineering analysis indicates two key expectations (Coats et al. 1971; Craig 1971; Zapata and Lake 1981; Sorbie and Seright 1992). First, as the mobility ratio becomes increasingly small (below unity), the vertical sweep efficiency increases for both the crossflow and no-crossflow cases. However, the crossflow cases achieve much higher recovery efficiencies than the no-crossflow cases. Second, as the mobility ratio becomes increasingly large (above unity), the sweep efficiency decreases for both the crossflow and no-crossflow cases. However, the crossflow cases suffer lower recovery efficiencies than the no-crossflow cases. To restate, crossflow cases lose efficiency much faster than the no-crossflow cases as the mobility ratio increases. These expectations are confirmed in Table 1. For 1-cp water displacing 1-cp oil in a two-layer reservoir, oil recoveries were higher for the crossflow cases than for the no-crossflow cases because the mobility ratios were favorable during the displacement. For 1-cp water displacing 10-cp oil, oil recoveries were approximately the same for the crossflow and no-crossflow cases because the mobility ratios were near unity during the displacement. For the 1-cp water displacing more-viscous oils, oil recoveries were less for the crossflow cases than for the no-crossflow cases because the mobility ratios were unfavorable during the displacement.

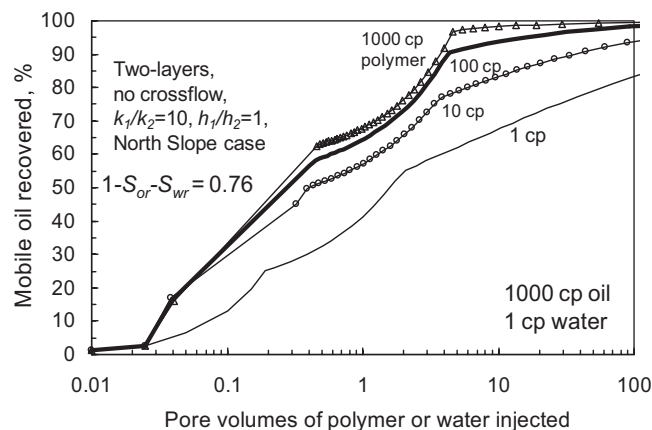
For the North Slope parameters, the mobile-oil saturation was considerably larger ( $1 - S_{or} - S_{wr} = 0.76$ ) than for our base case

TABLE 1—% MOBILE OIL RECOVERED AFTER 1 PV OF 1-CP WATER INJECTION						
Oil Viscosity, cp	1 Layer		2 Layers, No Crossflow		2 Layers With Crossflow	
	Base Case	North Slope Case	Base Case	North Slope Case	Base Case	North Slope Case
1	99	96	98	76	99	96
10	92	87	70	57	62	58
100	70	72	62	50	43	41
1,000	43	54	38	41	27	30
10,000	22	38	20	33	14	22
100,000	11	25	10	23	7	15

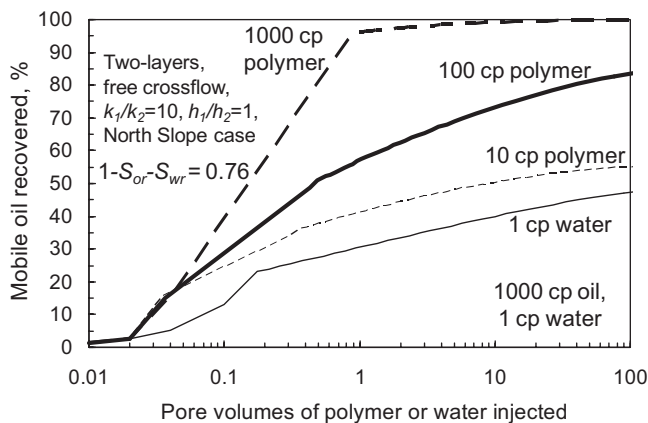




**Fig. 3—Polymer-flood results for one homogeneous layer, North Slope case.**



**Fig. 4—Polymer-flood results for two layers, no crossflow, North Slope case.**



**Fig. 5—Polymer-flood results for two layers, free crossflow, North Slope case.**

( $1-S_{or}-S_{wr}=0.4$ ). Consequently, there was a much bigger oil “target” for the North Slope case. At 1 PV, when the oil viscosity was greater than 100 cp, the waterflood response using the North Slope parameters appeared more favorable than for our base case (Table 1).

### Polymer Floods

Fractional-flow calculations were performed where a polymer flood was implemented to displace 1,000-cp oil. We used the same assumptions given in the preceding, except that polymer solution of a specified viscosity was injected. At the start of the flood, the connate-water saturation was either 0.3 (for the base cases) or 0.12 (for the North Slope cases) and water viscosity was 1 cp. (The “mobile” oil saturation was 100% at the start of polymer injection.) For the polymer, in addition to the assumptions mentioned earlier, we assumed (1) Newtonian (flow-rate-independent)

behavior, (2) properties were independent of permeability, and (3) polymer retention exactly balanced inaccessible PV. **Fig. 3** shows displacement results assuming only one homogeneous layer (for the North Slope case), while **Fig. 4** shows results for two layers ( $k_1=10k_2$ , equal layer thickness, same porosity) with no crossflow. **Fig. 5** shows results for two layers ( $k_1=10k_2$ , equal layer thickness, same porosity) with free crossflow. In each of the three figures, we show results for (1) 1-cp waterflooding, (2) 10-cp polymer injection, (3) 100-cp polymer injection, and (4) 1,000-cp polymer injection. **Table 2** summarizes the recovery values (percentage of the original mobile-oil saturation recovered) after injecting 0.5 PV of polymer solution. **Table 3** provides the same information after injecting 1 PV of polymer solution. [Of course, field polymer floods use finite bank sizes, in which various methods have been used to choose the appropriate bank size (Lake 1989; Wang et al. 2008b, 2009). Continuous polymer injection is used in this paper simply to provide a convenient means for comparison.]

One important observation from viewing Figs. 3 through 5 and Tables 2 and 3 is that increases in injectant viscosity virtually always lead to a significant increase in oil recovery. As expected, for any given water throughput and polymer-solution viscosity (except the 1,000-cp polymer cases), recovery efficiency was substantially better for the one-layer cases (Fig. 3) than for the two-layer cases (Figs. 4 and 5). Interestingly, the recovery curves when injecting 1,000-cp polymer solution were quite similar for both the one-layer cases and the two-layer cases with free crossflow (thick dashed curves in Fig. 3 vs. Fig. 5). This finding is consistent with vertical-equilibrium concepts. If the mobility contrast between the displacing and displaced phases [i.e.,  $(1\text{-darcy } k_{rw}/1,000\text{-cp oil})/(0.1\text{-darcy } k_{rw}/1,000\text{-cp polymer})=10$ ] is greater than or equal to the permeability contrast (i.e.,  $k_1/k_2=10$ ), then the displacement efficiency for two layers will appear to be the same as for one layer (Sorbie and Seright 1992).

For the one-layer cases and the two-layer cases with free crossflow, the waterfloods (i.e., 1-cp polymer) were noticeably more efficient (by 3 to 12% of the mobile oil) for the North Slope

**TABLE 2—% MOBILE OIL RECOVERED AFTER 0.5 PV POLYMER, 1,000-cp OIL**

Polymer Viscosity, cp	1 Layer		2 Layers, No Crossflow		2 Layers With Crossflow	
	Base Case	North Slope Case	Base Case	North Slope Case	Base Case	North Slope Case
1	36	48	31	32	22	27
10	53	59	45	51	37	38
100	70	64	56	59	53	51
1,000	73	66	60	63	72	62

Polymer Viscosity, cp	1 Layer		2 Layers, No Crossflow		2 Layers With Crossflow	
	Base Case	North Slope Case	Base Case	North Slope Case	Base Case	North Slope Case
1	43	54	38	41	27	30
10	70	72	53	57	42	41
100	92	87	63	64	62	57
1,000	99	96	66	67	99	96

conditions than the base case (see the first data rows of Tables 2 and 3). For the two-layer cases with no crossflow, the waterflood recoveries were quite similar for the North Slope and base cases (32 vs. 31% after 0.5 PV, respectively, and 41 vs. 38% after 1 PV, respectively).

At any given injection volume for the cases with no crossflow, the largest increases in recovery generally occurred when increasing the injectant viscosity from 1 to 10 cp (Fig. 4). For the cases with free crossflow (Fig. 5), the largest increase in recovery occurred when increasing the injectant viscosity from 100 to 1,000 cp. Most previous field polymer floods were directed at reservoirs with oil-/water-viscosity ratios that were less than 10, although the most successful projects had ratios from 15 to 114 (Taber et al. 1997b). For the world's largest (and most definitive) polymer flood, at Daqing, China, the oil-/water-viscosity ratio was 15, and 10 through 12% of the OOIP was recovered, incremental over waterflooding (Wang et al. 1995, 2008b, 2009; Taber et al. 1997b).

### Simple Benefit Analysis

Using the recovery results from Figs. 3 through 5, a simple benefit analysis was performed to make a preliminary assessment of the potential for polymer flooding in reservoirs with viscous oils. For much of this analysis, we made a pessimistic assumption that oil price was USD 20/bbl. We also assumed that water-treatment/injection costs were USD 0.25/bbl. We assumed that the polymer cost was USD 1.50/lbm. The open squares in Fig. 6 (associated with SNF Flopaam 3830S HPAM) were used for the relation between viscosity and polymer concentration. For viscosities greater than 10 cp, viscosity rises roughly with the square of polymer concentration. This behavior is an advantage when using polymer solutions to displace viscous oils. To explain, most previous conventional polymer floods (directed at oil viscosities less than 50 cp) used relatively low polymer concentrations (1,000 ppm or less). In this range, the relation between viscosity and polymer concentration is nearly linear, so viscosity and polymer-solution cost are directly proportional to polymer concentration. In this regime, if a doubling of viscosity is desired, a doubling of polymer-solution cost may be needed. For more-viscous oils,

higher polymer-solution viscosities may be needed for efficient oil displacement. For these more-viscous polymer solutions, a concentration exponent of two (i.e.,  $\mu \approx C^2$ ) means that doubling the solution viscosity can be achieved by increasing polymer concentration and cost by only 40%.

Other than water-handling and polymer-chemical costs, no other operating or capital costs were assumed in our economic analysis, so of course, this analysis is very rudimentary. Basically, for any given value of water or polymer solution injected, the relative profit is the total value of the oil produced minus the total cost of the polymer injected and also minus the total cost of water treatment to that point.

Figs. 7 and 8 show results from this analysis. [Many more results using other scenarios can be found in Seright (2009b).] The relative profit (USD profit per USD invested) from a given North Slope case was typically approximately twice that from a

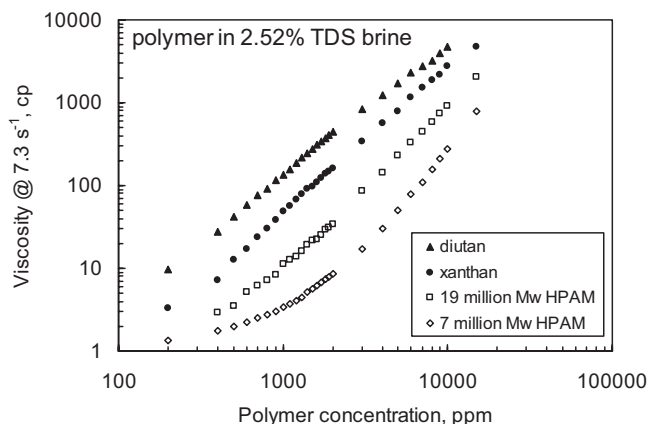


Fig. 6—Viscosity vs. polymer concentration.

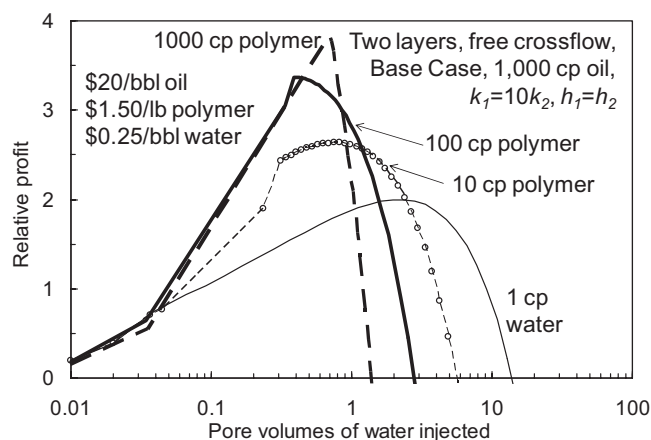


Fig. 7—Base case, two layers, free crossflow,  $k_1=10k_2$ , 1,000-cp USD 20/bbl oil.

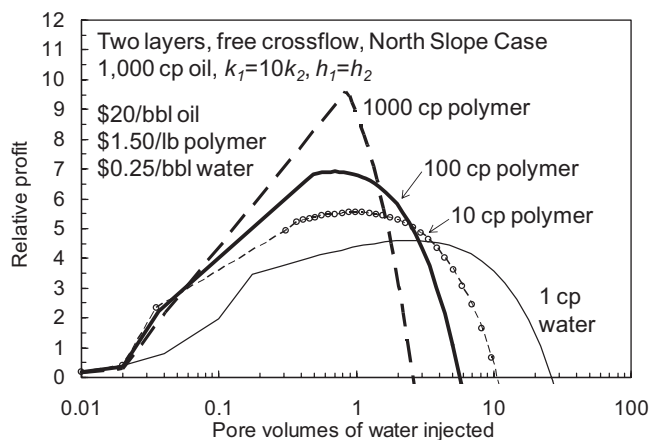


Fig. 8—North Slope case, two layers, free crossflow,  $k_1=10k_2$ , 1,000-cp USD 20/bbl oil.

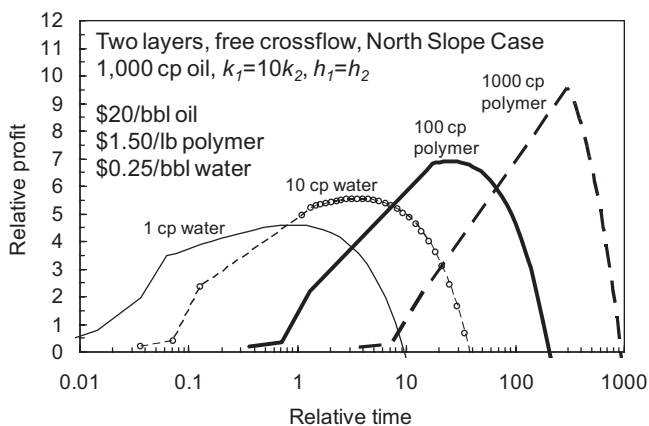


Fig. 9—Assuming that injectivity varies inversely with injection viscosity.

corresponding base case. This result occurs largely because the mobile-oil saturation for the North Slope case (0.76 PV) was 1.9 times greater than for our base case (0.4 PV). For most cases, the peak in profitability was noticeably greater when injecting polymer solution than for waterflooding. Also over a significant range of throughput values, polymer flooding provided a higher relative profit than waterflooding. Cases using other oil-price assumptions can be found in Seright (2009b). The basic shapes of the curves remain the same at various oil prices—just the magnitude of the relative profit rises in proportion to the oil price and the magnitude of the oil target. Of course, transportation, preparation, and other operating costs can be quite significant.

If the only issue was the value of the produced oil relative to the cost of the injectants, Figs. 7 and 8 indicate that injection of 1,000-cp polymer solutions might be preferred. Increasing the injected-polymer viscosity decreases the PV at which the peak profitability is observed and increases the relative profit (Figs. 7 and 8). However, that observation does not necessarily mean that polymer flooding will accelerate profits. If injectivity is assumed to be inversely proportional to polymer viscosity, Fig. 8 can be replotted as Fig. 9, which shows relative profit vs. relative time. Fig. 9 suggests that injecting a 10-cp polymer solution may be economically attractive over waterflooding, but the benefits from injecting 100- or 1,000-cp polymer solutions may be delayed for unacceptably long times. Our simple economic analysis to this point did not include present-value concepts. Thus, Figs. 7 through 9 suggest that for recovery of viscous oils, injectivity limitations are significantly more important than polymer costs. Consistent with previous literature (Morel et al. 2008), Fig. 9 emphasizes that maximizing injectivity of polymer solutions is a critical need. Use of horizontal wells and/or fractures to maximize injectivity and accelerate oil production appears key to implementation of polymer flooding for recovery of viscous oils. In particular, the operator may drill horizontal injector/producer pairs in the direction of the minimum stress for the formation. Then, fractures could be induced at regular intervals that are perpendicular to the wells. If the fractures are properly placed, injected polymer could flow linearly from the injection-well fractures to the production-well fractures, with greatly enhanced injectivity and productivity. Of course, care must be taken not to extend the fractures to the point that they cause direct channeling between the injection and production wells.

### Practical Impact of Permeability Reduction and Its Variation With Permeability

In the work to this point, we assumed that the polymer reduced mobility simply by increasing solution viscosity. Also, we assumed that the effective polymer-solution viscosity (resistance factor) was the same in all layers, regardless of permeability. Early work (Pye 1964; Smith 1970; Jennings et al. 1971; Hirasaki and Pope

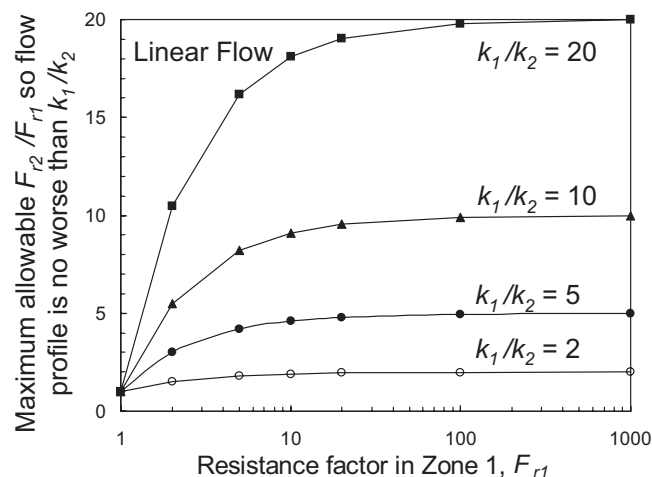


Fig. 10—Maximum allowable  $F_{r2}/F_{r1}$  for linear flow, no crossflow.

1974) recognized that high-molecular-weight HPAM sometimes reduced the mobility ( $\lambda$  or  $k/\mu$ ) of aqueous solutions in porous media by a greater factor than can be rationalized on the basis of the viscosity ( $\mu$ ) of the solution. The incremental reduction in mobility was attributed to reduction in permeability ( $k$ ), caused by adsorption or mechanical entrapment of the high-molecular-weight polymers—especially from the largest polymers in the molecular-weight distribution for a given polymer. In the 1960s and 1970s, this effect was touted to be of great benefit (Pye 1964; Jennings et al. 1971) for polymer floods (simply because the polymer appeared to provide significantly more apparent viscosity in porous media than expected from normal viscosity measurements). However, these benefits were often not achievable in field applications because normal field handling and flow through an injection sandface at high velocities mechanically degraded the large molecules that were responsible for the permeability reduction (Seright et al. 1981, 2010; Seright 1983). Also, the largest molecules were expected to be preferentially retained (i.e., by mechanical entrapment in pores) and stripped from the polymer solution before penetrating deep into the formation (Seright et al. 2010).

Even if high permeability reductions could be achieved, would this effect actually be of benefit? More specifically, the concern focuses on how the mobility reduction varies with permeability of porous media. For adsorbed polymers, resistance factors ( $F_r$ , apparent viscosities in porous media relative to brine) and residual resistance factors ( $F_{rr}$ , permeability-reduction values) increase with decreasing permeability (Pye 1964; Jennings et al. 1971; Hirasaki and Pope 1974; Vela et al. 1976; Jewett and Schurz 1970; Zaitoun and Kohler 1988; Rousseau et al. 2005). In other words, these polymers can reduce the flow capacity of low-permeability rock by a greater factor than for high-permeability rock. Depending on the magnitude of this effect, these polymers and gels can harm vertical-flow profiles in wells, even though the polymer penetrates significantly farther into the high-permeability rock (Seright 1988, 1991; Liang et al. 1993; Zhang and Seright 2007).

**Linear Flow, No Crossflow.** For the cases discussed earlier, the resistance factors (effective viscosities) in all layers (or “zones”) were assumed to be equal. Spreadsheets in Seright (2009a) are capable of performing calculations with different resistance factors in different zones (although only single-phase flow is considered). We used these spreadsheets to generate Fig. 10 for linear flow with no crossflow. The  $x$ -axis plots the resistance factor in Zone 1 ( $F_{r1}$ ). We are interested in how high the resistance factor can be in Zone 2 ( $F_{r2}$ ) without impairing the vertical sweep efficiency. The  $y$ -axis plots the maximum allowable ratio  $F_{r2}/F_{r1}$  that meets this criterion. These calculations were made for several permeability ratios  $k_1/k_2$  between 2 and 20. Fig. 10 shows that for  $F_{r1}$  values greater than 10, the maximum allowable ratio of  $F_{r2}/F_{r1}$  was approximately the same as the permeability ratio  $k_1/k_2$ . Thus, linear-flow applications

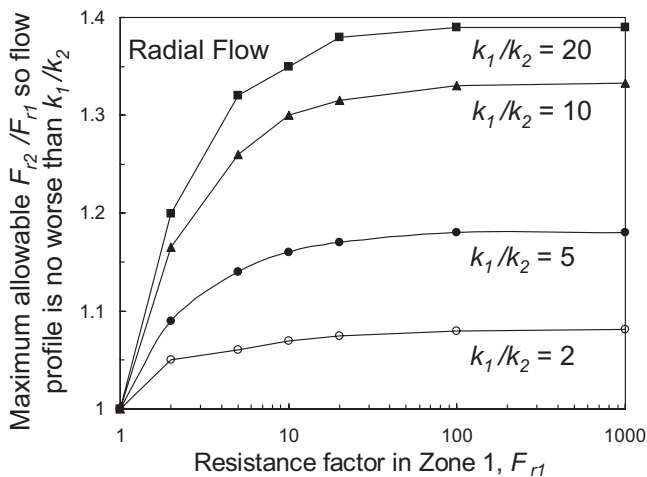


Fig. 11—Maximum allowable  $F_{r2}/F_{r1}$  for radial flow, no crossflow.

can be reasonably forgiving if the permeability contrast and the polymer-solution resistance factors are sufficiently large.

**Radial Flow, No Crossflow.** Similar calculations were performed for radial flow (with no crossflow), and the results are shown in Fig. 11. These calculations reveal that radial flow is much less forgiving to high values of  $F_{r2}/F_{r1}$ . Even for high permeability contrasts (e.g.,  $k_1/k_2 = 20$ ), the maximum allowable  $F_{r2}/F_{r1}$  values were less than 1.4.

**Comparison With Laboratory Data.** Jennings et al. 1971 and Vela et al. 1976 reported resistance factors obtained in cores with a wide range of permeability, using HPAM that had a molecular weight of approximately  $5 \times 10^6$  daltons (symbols in Fig. 12). The thick line in Fig. 12 plots the maximum acceptable behavior of resistance factors for linear-flow cases, while the thin line plots the maximum acceptable behavior of resistance factors for radial-flow cases. In these plots,  $F_{r1}$  refers to the measured resistance factor in the 453-md rock, while  $F_{r2}$  refers to the maximum acceptable resistance factor in a given less-permeable rock or zone. For the data provided, the measured behavior of resistance factors was barely acceptable for linear flow, and definitely unacceptable for radial flow. A logical remedy for this situation would be to choose a polymer with a lower molecular weight so resistance factors do not increase so much with decreasing permeability (Wang et al. 2008b, 2009). Whether or not a given polymer will be acceptable in a given reservoir may depend on a number of factors, including polymer molecular weight, rock permeability, water salinity, presence of residual oil, reservoir temperature, and possibly other factors (such as clay content, pore structure, and degree of mechanical degradation before entering the rock).

**Cases With Crossflow.** The discussion thus far in this section focused exclusively on cases with no potential for crossflow between layers (i.e., impermeable barriers exist between zones).

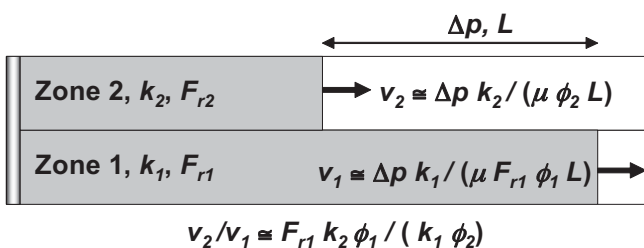


Fig. 13—Understanding front movements for linear flow with crossflow, moderate  $F_r$  values.

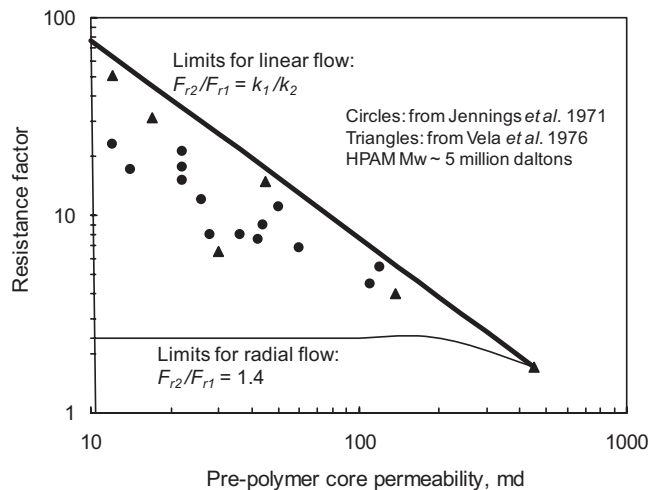


Fig. 12—Literature data compared with maximum allowable  $F_{r2}/F_{r1}$  values.

In most cases when crossflow can occur, the  $F_{r2}/F_{r1}$  ratio has little effect on the relative distance of polymer penetration into the various zones. To understand this conclusion, recognize that the distance between wells is usually much greater than the height of any given strata. If a pressure difference (after compensating for gravity) exists between two adjacent communicating zones, crossflow quickly reduces any pressure difference because of the close proximity of zones. These observations form the basis of the concept of vertical equilibrium (Coats et al. 1971; Zapata and Lake 1981; Sorbie and Seright 1992). For vertical equilibrium, the pressure gradients in two adjacent zones (with no flow barriers) are the same for any given horizontal position. Put another way, for a given distance from the wellbore (if gravity can be neglected), the pressure is the same in both zones.

Consider a polymer solution (gray in Fig. 13) displacing water (white in Fig. 13) when flowing through two adjacent zones where crossflow can occur. Zone 1 (the high-permeability layer) has a permeability of  $k_1$ , a porosity of  $\phi_1$ , and exhibits a polymer resistance factor of  $F_{r1}$ . Zone 2 (the low-permeability layer) has a permeability of  $k_2$ , a porosity of  $\phi_2$ , and exhibits a polymer resistance factor of  $F_{r2}$ . The average movement rates for polymer fronts in the two zones are  $v_1$  and  $v_2$ , respectively. Of course, crossflow may make the polymer front uneven (i.e., not vertical) in Zone 2. So in the simple analysis here, we consider the average front positions. If vertical equilibrium exists, the pressure difference between the polymer fronts will be the same in the two zones. Darcy's law can then be applied to estimate the average front movement rates. For Zone 2, this rate,  $v_2$ , is given by

$$v_2 \equiv \Delta p k_2 / (\mu \phi_2 L) \quad \dots \dots \dots (5)$$

For Zone 1, this rate,  $v_1$ , is given by

$$v_1 \equiv \Delta p k_1 / (\mu F_{r1} \phi_1 L) \quad \dots \dots \dots (6)$$

The ratio of average front rates is given by

$$v_2/v_1 \equiv F_{r1} k_2 \phi_1 / (k_1 \phi_2) \quad \dots \dots \dots (7)$$

Consequently, the relative rate of polymer-front movement is not sensitive to the resistance factor in Zone 2. Eq. 7 is the same expression that is derived when resistance factors are equal for the two zones (Sorbie and Seright 1992).

**Effect of Differential Retention.** For many years, people have recognized that polymer resistance factors, residual resistance factors, and chemical-retention values in porous media increase with decreasing permeability (Jennings et al. 1971; Vela et al. 1976; Zaitoun and Kohler 1987). These trends impede polymer



propagation in the less-permeable zones and, therefore, do not aid vertical sweep (Seright 1988, 1991).

**Summary.** For applications with linear flow (e.g., fractured wells) with no crossflow, the maximum allowable ratio of  $F_{r2}/F_{r1}$  (so that polymer injection does not harm vertical sweep) is approximately the same as the permeability ratio  $k_1/k_2$ . Thus, linear-flow applications can be reasonably forgiving if the permeability contrast and the polymer-solution resistance factors are sufficiently large. Radial flow (with no crossflow) is much less forgiving to high  $F_{r2}/F_{r1}$  values. Even for high permeability contrasts (e.g.,  $k_1/k_2 = 20$ ), the maximum allowable  $F_{r2}/F_{r1}$  values were less than 1.4. When crossflow can occur, the  $F_{r2}/F_{r1}$  ratio has little effect on the relative distance of polymer penetration into the various zones.

### Impact of Rheology

Our work to this point assumed that polymer-solution rheology was Newtonian (flow-rate independent). Recently, some authors suggested that shear thinning exhibited by polymer solutions is detrimental to sweep efficiency (Deshad et al. 2008; AlSofi et al. 2009; AlSofi and Blunt 2009). They cited Jones (1980) to support their position. Jones argued that if two noncommunicating layers of different permeability were completely filled with a shear-thinning fluid, the vertical-flow profile would be worse than for a Newtonian fluid. Although correct (and verified by Table 2 of Seright 1991), the argument is not relevant to polymer floods. In a polymer flood, a viscous polymer solution displaces oil and/or water. For this circumstance, the overall viscosity (resistance factor) of the polymer solution is of far greater relevance than the rheology (Seright 1991). This point can be appreciated by considering several cases. In each case, a fluid with a given viscosity/rheology is injected to displace 1-cp water from a two-layer porous medium.

**Free Crossflow.** First, consider adjacent layers that have substantially different permeabilities, but free crossflow (vertical equilibrium) occurs between the layers. The vertical sweep efficiency is insensitive to the rheology of the injection fluid (within reasonable limits that are achievable by xanthan or HPAM) if a sufficiently stable displacement is maintained (Sorbie and Seright 1992; Zhang and Seright 2007). For a specific example, consider a 600-ppm xanthan solution that exhibits a power-law exponent of 0.5 in Berea sandstone (Figs. 1 and 2 of Seright et al. 2010). For an applied pressure gradient of 2.4 psi/ft, the solution resistance factors were measured as 13.3 in 55-md Berea and 8.1 in 269-md Berea. If this information is entered into Eq. 7, an efficient vertical sweep is predicted, even though a fivefold permeability contrast exists between the layers. Consideration of Eq. 7 reveals that vertical sweep efficiency would be no different for a Newtonian, or shear-thickening, fluid. Experimental verification of this point can be found at <http://baervan.nmt.edu/randy/> (more specifically, the link to Videos of Polymer Flooding and Crossflow Concepts). Consequently, for cases with crossflow, a fear of using shear-thinning fluids is not warranted.

Some elaboration may be needed to appreciate the role of rheology. We look further at the preceding example for xanthan at 2.4 psi/ft, which results in a resistance factor of 13.3 in 55-md rock and 8.1 in 269-md rock. One might assume that because the resistance factor is greater in the low-permeability layer, the fluid velocity is accentuated in the high-permeability layer, relative to the velocity in the adjacent low-permeability layer. This assumption is correct near the injection well, where polymer is present in both layers at the same horizontal position (i.e., where both Zones 1 and 2 are shaded gray in Fig. 13). In our example, near the injection well, the polymer solution is moving eight times faster in the high-permeability layer than in the low-permeability layer [i.e.,  $(269/55) \times (13.3/8.1)$ ]. If only brine was present (i.e., before polymer injection), brine travels 4.9 times faster in the high-permeability layer than in the low-permeability layer (i.e.,  $269/55$ ). Thus, if a flow profile is measured at the injection wellbore (or at most horizontal locations where polymer is present in both layers), the shear-thinning xanthan solution appears to harm vertical sweep efficiency. However, this perception is incorrect. To appreciate why, focus on what happens just downstream of

the polymer front in Zone 2 (the low-permeability layer in Fig. 13). Because of vertical equilibrium, the pressure gradient at that horizontal position is the same in both layers. The fluid at this horizontal position is water (with a resistance factor of unity) in Zone 2 and is polymer solution (with a resistance factor of 8.1) in Zone 1. The Darcy equations in Fig. 13 help to estimate the horizontal fluid velocities in the two layers at that position. Entering the permeability and resistance-factor values  $[(269/55) \times (1/8.1)]$  yields a value of 0.6, suggesting that the front velocity in the low-permeability layer actually has the potential to travel faster than fluid in the high-permeability layer. Of course, this is not physically possible, because the pressure gradients involved would equalize the flow so that the velocity in the low-permeability layer never exceeds that in the high-permeability layer. But the analysis emphasizes that the polymer front in the low-permeability layer can travel at the same rate as the front in the high-permeability layer. To accomplish this, polymer from the high-permeability layer crossflows into the low-permeability layer in the vicinity of the polymer front. The relative fluid velocities upstream of the polymer front (e.g., near the injection well) are largely irrelevant. This leaves us with the situation that flow profiles taken at the injection well *incorrectly* suggest that a shear-thinning fluid has harmed vertical sweep efficiency, whereas in reality, the vertical sweep is as good as it can possibly be (i.e., the same front velocity in both layers). One can experiment with the equations associated with Fig. 13 to appreciate that rheology has a less important effect on vertical sweep efficiency than the overall viscosity level of the polymer solution. For example, using resistance factors of 13.3 in the high-permeability zone and 8.1 in the low-permeability zone (i.e., shear-thickening behavior) results in the polymer fronts moving at the same rate in both layers—just as it did with shear-thinning behavior. In contrast, if the resistance factors have a value of two in both layers, the polymer front in the low-permeability zone moves at only 41% of the rate in the high-permeability zone (i.e.,  $2 \times 55/269$ ).

**No Crossflow, Radial Flow.** Next, consider layers or pathways that are distinctly separated (i.e., no crossflow between layers). For two noncommunicating layers with a tenfold permeability contrast, the central columns of Table 4 [calculations taken from Seright (1991)] show the relative differences for the displacement (polymer) fronts with radial flow of various rheologies and for factors up to a 100-fold difference in applied pressure drop between the well and the outer drainage radius. In Table 4, four Newtonian cases are listed.  $F_r=1$  means that the injected fluid has the same viscosity as the water that is being displaced.  $F_r=1,000$  means that the injected fluid is 1,000 times more viscous than the water that is being displaced. The low-viscosity shear-thinning fluid in Table 4 was based on a 200-ppm xanthan solution and a Carreau model that had a zero-shear resistance factor of 2.25, a power-law exponent of 0.88, and a second-Newtonian-region resistance factor of 1.1. The high-viscosity shear-thinning fluid was based on a 2,400-ppm xanthan solution and a Carreau model that had a zero-shear resistance factor of 182, a power-law exponent of 0.36, and a second-Newtonian-region resistance factor of 1.5 [from Fig. 2 of Seright (1991)]. The low-viscosity shear-thickening fluid in Table 4 was based on a 1-million-dalton HPAM and a Heemskerk model (Heemskerk 1984) that provided resistance factors of  $\approx 7$  at low flux and 20 at 1,000 ft/D. The high-viscosity shear-thickening fluid was based on a 26-million-dalton HPAM and a Heemskerk model that provided resistance factors of  $\approx 100$  at low flux and 1,000 at 100 ft/D [Fig. 3 of Seright (1991)].

For very high pressure drops in Table 4 (i.e., 5,000 psi over 50 ft), the high-viscosity shear-thickening model indicated a flow profile that was 17% more favorable than that for a 100-cp Newtonian fluid (0.417 vs. 0.357), which in turn was 10% more favorable than for the high-viscosity shear-thinning fluid (0.357 vs. 0.325). These differences were not particularly large, and they diminished when lower, more-realistic pressure drops were applied. For a pressure drop of 50 psi over more than 50 ft (first data column of Table 4), only a 1.5% difference separated the high-viscosity shear-thickening fluid from the high-viscosity shear-thinning fluid (0.344 vs. 0.339).



**TABLE 4—DISTANCE OF POLYMER PENETRATION INTO A 100-md LAYER RELATIVE TO THAT IN A 1,000-md LAYER (NO CROSSFLOW)**

Data from Seright 1991	Radial Flow			Linear Flow			
	$(r_{p2}-r_w)/(r_{p1}-r_w)$			$L_{p2}/L_{p1}$			
Pressure drop (psi over 50 ft for radial flow) or pressure gradient (psi/ft, for linear flow):	50	500	5,000	1	10	100	1,000
Assumed rheology:							
Newtonian, $F_r=1$	0.309	0.309	0.309	0.100	0.100	0.100	0.100
Newtonian, $F_r=10$	0.352	0.352	0.352	0.256	0.256	0.256	0.256
Newtonian, $F_r=100$	0.357	0.357	0.357	0.309	0.309	0.309	0.309
Newtonian, $F_r=1,000$	0.358	0.358	0.358	0.316	0.316	0.316	0.316
Low-viscosity, shear-thinning, Xanthan, Carreau model	0.329	0.326	0.324	0.145	0.136	0.129	0.123
High-viscosity, shear-thinning, Xanthan, Carreau model	0.339	0.326	0.325	0.312	0.295	0.172	0.131
Low-viscosity, shear-thickening, HPAM, Heemskerck model	0.343	0.365	0.379	0.201	0.194	0.236	0.274
High-viscosity, shear-thickening, HPAM, Heemskerck model	0.344	0.410	0.417	0.299	0.300	0.311	0.315

**No Crossflow, Linear Flow.** Most polymer floods to date may have had open fractures intersecting the injection wells (Seright et al. 2009c). Therefore, linear-flow cases may be the most relevant. In the right-hand columns of Table 4 (the cases for linear flow with no vertical communication between layers), there are large percentage differences in the vertical-flow profiles for different rheologies. For some cases at high pressure gradients, the shear-thinning fluid gave a noticeably less efficient displacement than for the Newtonian or shear-thickening fluids. However, the differences were most pronounced at high pressure gradients that are unlikely to be achieved in real field applications (>10 psi/ft). For relatively low pressure gradients, the high-viscosity shear-thinning fluid gave a vertical sweep no worse than the Newtonian, or shear-thickening, fluids. In summary, for practical conditions during polymer floods, the vertical sweep efficiency using shear-thinning fluids is not expected to be dramatically different from that for Newtonian, or shear-thickening, fluids. As mentioned earlier, the overall viscosity (resistance factor) of the polymer solution is of far greater relevance than the rheology.

### Conclusions

This paper examined some important aspects of polymer flooding reservoirs with viscous oils, especially in reservoirs that preclude the application of thermal methods. The following conclusions were noted:

- (1) A reconsideration of EOR screening criteria revealed that higher oil prices, modest polymer prices, increased use of horizontal wells, and controlled injection above the formation-parting pressure all help considerably to extend the applicability of polymer flooding in reservoirs with viscous oils.
- (2) Fractional-flow calculations demonstrated that the high mobile-oil saturation, degree of heterogeneity, and relatively free potential for crossflow in our target North Slope reservoirs also promote the potential for polymer flooding.
- (3) For cases with no crossflow between layers, most of the benefit from polymer flooding a two-layer reservoir with 1,000-cp oil materializes using a 10-cp polymer solution. A smaller incremental benefit occurs when using more-viscous polymer solutions.
- (4) For cases with free crossflow between layers where a polymer flood occurs in a two-layer reservoir with 1,000-cp oil, injection of more-viscous polymer solutions (i.e., 100 to 1,000 cp) is favored over a 10-cp polymer solution, if injectivity limitations are not present.
- (5) A simple benefit analysis suggested that reduced injectivity may be a greater limitation for polymer flooding of viscous oils than the cost of chemicals. For existing EOR polymers, viscosity increases roughly with the square of polymer concentration—a fact that aids the economics for polymer flooding of viscous oils. Of course, many costs can influence the feasibility

of polymer flooding, including transportation, preparation, and other operating costs.

- (6) Various cases were considered where resistance factors were greater in low-permeability layers than in high-permeability layers (i.e.,  $F_{r2} > F_{r1}$ ). For applications with linear flow (e.g., fractured wells) with no crossflow, the maximum allowable ratio of  $F_{r2}/F_{r1}$  (so that polymer injection does not harm vertical sweep) is approximately the same as the permeability ratio  $k_1/k_2$ . Thus, linear-flow applications can be reasonably forgiving if the permeability contrast and the polymer-solution resistance factors are sufficiently large. Radial flow (with no crossflow) is much less forgiving to high  $F_{r2}/F_{r1}$  values. Even for high permeability contrasts (e.g.,  $k_1/k_2 = 20$ ), the maximum allowable  $F_{r2}/F_{r1}$  values were less than 1.4. When crossflow can occur, the  $F_{r2}/F_{r1}$  ratio has little effect on the relative distance of polymer penetration into the various zones.
- (7) For practical conditions during polymer floods, the vertical sweep efficiency using shear-thinning fluids is not expected to be dramatically different from that for Newtonian, or shear-thickening, fluids. The overall viscosity (resistance factor) of the polymer solution is of far greater relevance than the rheology.

### Nomenclature

- $C$  = polymer concentration, ppm [g/cm<sup>3</sup>]
- $F_r$  = resistance factor (water mobility/polymer solution mobility)
- $F_{rr}$  = residual resistance factor (water mobility before polymer/water mobility after polymer)
- $F_{r1}$  = resistance factor in Layer 1 (high-permeability layer)
- $F_{r2}$  = resistance factor in Layer 2 (low-permeability layer)
- $h$  = formation height, ft [m]
- $h_1$  = height of Zone 1, ft [m]
- $h_2$  = height of Zone 2, ft [m]
- $k$  = permeability, darcies [ $\mu\text{m}^2$ ]
- $k_{ro}$  = 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 Zone 1, darcies [ $\mu\text{m}^2$ ]
- $k_2$  = permeability of Zone 2, darcies [ $\mu\text{m}^2$ ]
- $L$  = linear distance, ft [m]
- $L_{p1}$  = linear distance of polymer penetration into the high-permeability layer, ft [m]
- $L_{p2}$  = linear distance of polymer penetration into the low-permeability layer, ft [m]
- $no$  = oil-saturation exponent in Eq. 2
- $nw$  = water-saturation exponent in Eq. 1
- $PV$  = pore volumes of fluid injected
- $r_{p1}$  = radius of polymer penetration into the high-permeability layer, ft [m]

$r_{p2}$  = radius of polymer penetration into the low-permeability layer, ft [m]  
 $r_w$  = wellbore radius, ft [m]  
 $S_{or}$  = residual-oil saturation  
 $S_w$  = water saturation  
 $S_{wr}$  = residual-water saturation  
 $u$  = flux, ft/D [m/d]  
 $v_1$  = front velocity in Zone 1, ft/D [m/d]  
 $v_2$  = front velocity in Zone 2, ft/D [m/d]  
 $\lambda$  = mobility, darcies/cp [ $\mu\text{m}^2/\text{mPa}\cdot\text{s}$ ]  
 $\mu$  = viscosity, cp [mPa·s]  
 $\phi$  = porosity  
 $\phi_1$  = porosity in Zone 1  
 $\phi_2$  = porosity in Zone 2  
 $\Delta p$  = pressure difference, psi [Pa]  
 $\Delta \rho$  = density difference, g/cm<sup>3</sup>

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### SI Metric Conversion Factors

°API	141.5/(131.5+°API)	= g/cm <sup>3</sup>
bbl	× 1.589 873	E-01 = m <sup>3</sup>
cp	× 1.0*	E-03 = Pa · s
ft	× 3.048*	E-01 = m
gal	× 3.785 412	E-03 = m <sup>3</sup>
lbm	× 4.535 924	E-01 = kg
psi	× 6.894 757	E+00 = kPa

\*Conversion factor is exact.

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