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How Much Polymer Should Be Injected During a Polymer Flood?

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Abstract

This paper addresses two questions for polymer flooding. First, what polymer solution viscosity should be injected? A base-case reservoir-engineering method is present for making that decision, which focuses on waterflood mobility ratios and the permeability contrast in the reservoir. However, some current field applications use injected polymer viscosities that deviate substantially from this methodology. At one end of the range, Canadian projects inject only 30-cp polymer solutions to displace 1000-3000-cp oil. Logic given to support this choice include (1) the mobility ratio in an unfavorable displacement is not as bad as indicated by the endpoint mobility ratio, (2) economics limit use of higher polymer concentrations, (3) some improvement in mobility ratio is better than a straight waterflood, (4) a belief that the polymer will provide a substantial residual resistance factor (permeability reduction), and (5) injectivity limits the allowable viscosity of the injected fluid. At the other end of the range, a project in Daqing, China, injected 150-300-cp polymer solutions to displace 10-cp oil. The primary reason given for this choice was a belief that high molecular weight viscoelastic HPAM polymers can reduce the residual oil saturation below that expected for a waterflood or for less viscous polymer floods. This paper will examine the validity of each of these beliefs.

The second question is: when should polymer injection be stopped or reduced? For existing polymer floods, this question is particularly relevant in the current low oil-price environment. Should these projects be switched to water injection immediately? Should the polymer concentration be reduced or graded? Should the polymer concentration stay the same but reduce the injection rate? These questions are discussed.

What Polymer Concentrations/Viscosities and Bank Sizes Have Been Used in the Past?

1960-1980

The history of field applications for polymer flooding can be divided into three periods. The first period extends from the first implementation of polymer flooding (~1960) through 1980. For 92 projects (both field and pilot), Manning *et al*. (1983) reported a median injected polymer concentration of 250-260 ppm. The vast majority of these projects used HPAM (hydrolyzed polyacrylamide or acrylamide-acrylate copolymer). Prior to polymer flooding the median water/oil mobility ratio was about 5. The median polymer bank size was quite small—only 17% pore volume (PV) for field-wide projects and 5% PV for pilot projects. During this historical period, the choice of low polymer concentrations and small polymer banks were predicated on two beliefs, which are now known to be misleading or incorrect. The first belief was that HPAM polymer provided a substantial permeability reduction (residual resistance factor) that would benefit the floods by providing much more mobility reduction than expected from viscosity measurements and by improving the mobility ratio during post-polymer water flooding (Pye 1964, Knight and Rhudy 1977). Unfortunately, the very high-molecular-weight (*Mw*) polymer species that caused this effect in short laboratory cores is unlikely to propagate very far into a reservoir (Seright 2010 and Seright *et al*. 2011). The second belief was that small polymer banks would preferentially enter high-permeability strata, allowing subsequently injected water to be diverted to displace oil from less-permeable strata (Needham and Doe 1987, Chang *et al*. 2006). Unfortunately, injected water preferentially fingers first through polymer banks in the most-permeable pathways (Cyr *et al*. 1988, Sorbie and Seright 1992, Seright *et al*. 2012). This realization has led to larger polymer bank sizes over time, as demonstrated by Fig. 1 of Sheng *et al*. (2015).

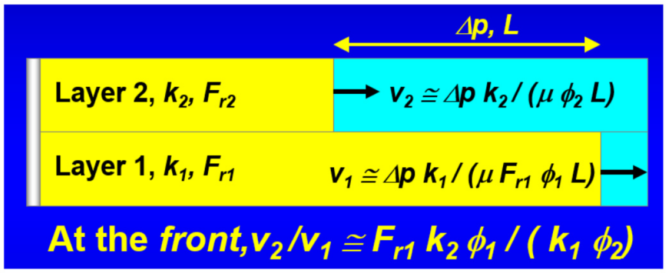

Figure 1—Simple basis for the method.

1980-1990

Up to 1990, a number of well-documented field projects were performed that advanced our knowledge of polymer flooding. These included Coalinga (Duane and Dauben 1983), Courtenay/Chateaurenard (Putz *et al*. 1994), Daqing (Wang *et al*. 1995), Marmul (Koning *et al*. 1988), North Burbank (Zornes *et al*. 1986), North Stanley (DuBois and Burtch 1978), Oerrel and Hankensbuettel (Maitin and Volz 1981), Oregon Basin and Byron (DeHekker *et al*. 1986), Eliasville Caddo (Weiss and Baldwin 1985), Rapdan (Pitts *et al*. 1995), Storms Pool (Craig 1984, Norton and Dauben 1986), and West Yellow Creek (Holstein 1981). Unfortunately, the Windfall Profits Tax Act of 1980 stimulated a large number of polymer projects between 1980 and 1986 that were motivated solely to achieve tax reductions. During this time period, the median polymer concentration for 171 projects was 460 ppm (primarily HPAM) and the median volume of polymer solution injected was 10% PV (Seright 1993). In contrast, polymer concentrations for the well-documented projects listed above were typically 1000-1500 ppm; and polymer bank sizes usually ranged from 25% to 100% PV. The large number of 1980s tax-driven projects strongly skews statistical analyses of polymer floods, and can lead to the erroneous conclusion that polymer flooding is applicable in virtually all conventional reservoirs (Saleh *et al*. 2014).

1990-Present

For the most recent historical period, injected HPAM solutions have generally used 1000-ppm HPAM or greater and relatively large bank sizes. The world's largest polymer flood was implemented at Daqing, China, in 1996 to displace 9-10-cp oil (Wang *et al*. 1995, Wang *et al*. 2008a,b, Wang *et al*. 2009, Wang *et al*. 2011). [Polymer flooding pilot tests were performed at Daqing since 1972 (Wang *et al*. 2009).] The first 12 years of the large-scale Daqing project typically used 1000-1300-ppm HPAM (15-18 million g/mol), providing 40-50-cp surface viscosity. Typically, around 1 PV of polymer solution was injected for a given pattern, although a significant amount of variation and experimentation occurred to optimize performance (Han 2015). Since 2002, Daqing increasingly tested and implemented injection of 2000-2500-ppm HPAM (20-35 million g/mol), providing 150-300-cp polymer solutions to displace the same 9-10-cp oil (Wang *et al*. 2011). Bank sizes reported for this high-concentration process ranged from 0.4 to 1.2 PV. Table 1 lists information for other recent polymer floods. Polymer concentrations and bank sizes for recent projects have been considerable greater than for projects prior to 1990. Note the wide range of ratios of oil viscosity to injected polymer viscosity in Table 1—apparently reflecting a wide range of beliefs about the mobility ratio need for an effective polymer flood.

Table 1—Polymer injected during recent polymer floods.

Field	C_{poly}, ppm	μ_{poly}, cp	μ_o @ Res. T, cp	Endpoint M	k_{cont}	μ_{poly}, [M*k_{cont}]	Bank size, PV	Graded?
Daqing, China (1996-~2008)	1000-1300	40-50	9-10	9-10	4:1	~1	~1	Mixed
Daqing, China (~2008-2016)	2000-2500	150-300	9-10	9-10	4:1	3-8	0.4-1.2	Mixed
Gudao/Shengli, China	2000	25-35	50-150				0.4-0.6	
Shengtao/Shengli, China	1800	30-50	10-40				0.4-0.6	
ShuangHe, China	1090	93	7.8		4:1		0.4	yes
Bohai Bai, China	1200-2500	98	30-450		4:1		0.11-0.3	
Pelican Lake, Canada	600-3000	13-200	~1650	~165	4:1	0.02-0.3	0.5-2	
East Bodo, Canada	1500	50-60	417-2000	~42				
Mooney, Canada	1500	20-30	100-250					
Seal, Canada	1000-1500	25-45	3000-7000					
Suffield Caen, Canada	1300	32	69-99	44-64	4:1	~0.2	0.6	
Wainwright, Canada	2100-3000	25	100-200				0.5	yes
Dalia, Angola	900	3	1-11		10:1		0.5	yes
Diadema, Argentina	1500-3000	15-40	100	80	9:1	~0.06	0.8	
El Corcobo, Argentina	1000	20-25	160-300					
Matzen, Austria	900	10	19	17				yes
Canto do Amaro, Brazil	1000	30	50	12			0.1	
Carmopolis, Brazil	500	40	10.5	3			0.16	
Buracica, Brazil	500	10	7-20	2-5			1.1	
Bockstedt, Germany	300 (biopoly)	25	11-29		3:1			
Mangala, India	2000-2500	20	9-22	36	10:1	~0.06	0.8	yes
Marmul, Oman	1000	15	80-90	~40	10:1	~0.04	1	
Tambaredjo, Suriname	1000-2500	45-140	325-2209	40-50	12:1	~0.4		

Floods involving ″colloidal dispersion gels″ are sometimes labeled as polymer floods or substitutes for polymer flooding (Chang *et al*. 2006). In contrast to recent polymer floods, these ″CDG″ floods still follow the philosophy of low polymer concentrations and small bank sizes Manrique *et al*. 2014). A detailed analysis of the literature reveals that these CDG materials cannot be expected to propagate very far into a reservoir (Seright 2015).

Al-Saadi *et al*. 2012, Buciak *et al*. 2015, Delaplace *et al*. 2013, Gao 2014, He *et al*. 1998, Hyrc *et al*. 2013, Irving *et al*. 2012, Kang *et al*. 2011. Liu *et al*. 2012. De Melo *et al*. 2005, Morel *et al*. 2012, Prasad *et al*. 2014, Saboorian-Jooybari *et al*. 2015, Sheng *et al*. 2015, Thakuria *et al*. 2013, Wassmuth *et al*. 2009.

Base-Case Method for Estimating the Required Polymer Viscosity

Crossflow between Layers

A simple method is available to estimate a base-case viscosity for injection during a polymer flood (Sorbie and Seright 1992, Wang *et al*. 2008a). This method estimates the desired polymer viscosity (relative to water viscosity) as the product of mobility ratio (M, mobility of the displacing phase relative to the displaced phase) times the permeability contrast (k_{cont}, between adjacent layers in the reservoir; high-permeability divided by low-permeability). In this method, an important issue is: what value should be assigned for the mobility contrast? This question will be addressed in the next section. However, for simplicity in illustrating the method, the first focus is on cases where polymer solutions are injected to miscibly displace water. Fig. 1 provides a basis for the method in a two-layer porous medium with free crossflow between the layers. Assume that a polymer solution (yellow in Fig.1) is injected to displace water (light blue, with viscosity, μ). Layer 1 has permeability, k_1, and porosity, φ_1; while Layer 2 has permeability, k_2, and porosity, φ_2. In Layer 1, the polymer resistance factor is F_{r1} in Layer 1 (meaning that effective viscosity of the polymer solution is F_{r1} times greater than water) and F_{r2} in Layer 2. If vertical equilibrium (Coats *et al*. 1971, Zapata and Lake 1981) can be assumed (and gravity and capillary forces can be neglected), at any given horizontal position along Fig. 1, the pressure in Layer 1 is the same as that in Layer 2. This condition is generally true in reservoirs with no barriers to vertical flow if the length to width ratio is 10 or greater (i.e., the injector-producer distance is more than 10 times greater than the formation thickness) (Zapata and Lake 1981). For simplicity of visualization, the vertical interfaces between the light blue and the yellow in Fig. 1 show the polymer front positions in Layers 1 and 2. Because of vertical equilibrium, the pressure difference, Δp, over the distance, L, is the same in both layers. Consequently, the Darcy equations listed in Fig. 1 show approximations for the velocities of the polymer fronts in the two layers, while the bottom equation in Fig. 1 shows the approximate ratio of the two front velocities:

$$v_2/v_1 \approx (F_{r1}\, k_2\ \ \phi_1\,)\;/\;(k_1\phi_2) \tag{1}$$

When $F_{r1} = 1$ (i.e., water displaces water), the ratio of front velocities, v_2/v_1, is given by the permeability-porosity ratio, $(k_2ø_1)/(k_1ø_2)$, as expected from the simplest form of Darcy's law. Eq. 1 predicts that the ratio of front velocities increases in direct proportion to the resistance factor, F_{r1}—until F_{r1} reaches the permeability-porosity ratio, $(k_2ø_1)/(k_1ø_2)$. Above this value, the equation predicts that the polymer front in the low-permeability layer will out run that in the high-permeable layer—which of course will not happen.

In reality, the polymer front in Layer 2 will not be vertical, because of local pressure gradients and crossflow in the region between the polymer front in Layer 2 and that in Layer 1. Fig. 2 shows actual polymer front profiles from experiments where polymer solutions (with viscosities ranging from 1 cp to 75 cp) displaced water in two-layer bead packs (Sorbie and Seright 1992). For each of five cases shown in this figure, Layer 1 was 11.2 times more permeable than Layer 2. (Layers 1 and 2 have the same porosity.) Red-dyed xanthan solutions (with viscosities at 7.3 s^{-1} ranging from 1 cp to 75 cp) were injected to displace blue 1-cp water. Videos of these displacements can be found at www.prrc.nmt.edu/randy or by entering ″Randy Seright″ into the search engine of YouTube. Watching these videos reveals that for the cases of 23-cp and 75-cp polymer solutions, the polymer fronts in the Layers 1 and 2 move at the same velocity—as predicted by Eq. 1 because F_{r1} (i.e., 23 and 75) is greater than the permeability-porosity contrast, $(k_1ø_2)/(k_2ø_1)$ (i.e., 11.2:1). The fronts in Layer 2 are angled and lag behind those in Layer 1 because the local pressure gradients cause extensive polymer crossflow (from Layer 1 into Layer 2) in the angled region. In other words, in an attempt of achieve vertical equilibrium, polymer is forced from Layer 1 to Layer 2 in the angled region. If Layer 2 was thicker, the polymer front in Layer 2 would follow a fixed angle (for a given viscosity case) as the thickness of Layer 2 increased. Also, the angle of inclination for the front in Layer 2 for the 75-cp-polymer case is steeper than that for the 23-cp-polymer case. This occurs because the local pressure gradients that push polymer into Layer 2 (in the angled region) are greater for the 75-cp-polymer case than the 23-cp-polymer case.

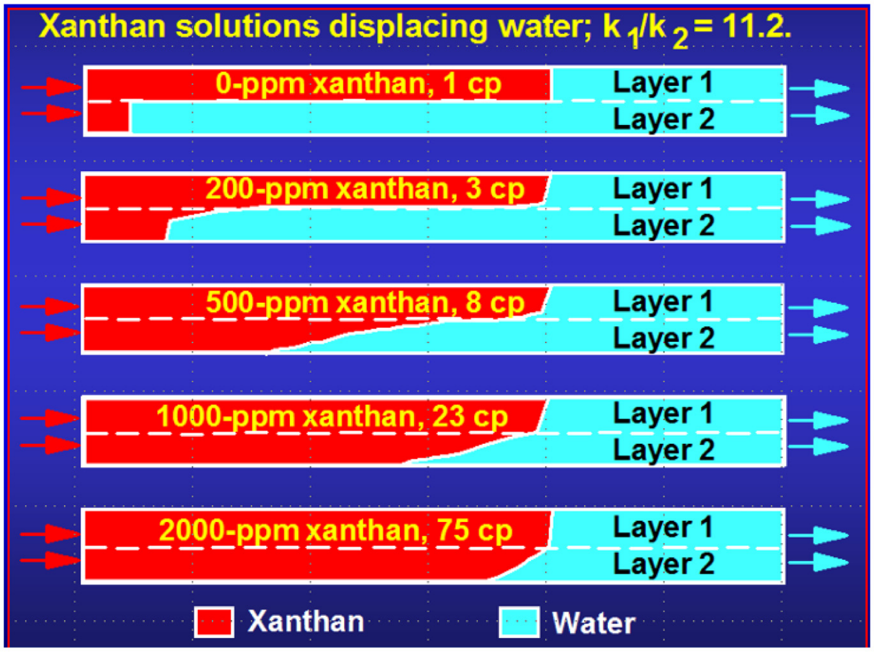

Figure 2—Polymer solutions displacing water in two-layer bead packs with crossflow.

For the case of 1-cp water (i.e., 0-ppm polymer) displacing water in Fig. 2, the videos reveal that the front in Layer 2 moves 11.2 times slower than that in Layer 1—just as is predicted by Eq. 1.

For the cases of 3-cp and 8-cp polymer displacing water, the front movements are a bit more complex and are intermediate between the 1-cp and 23-cp cases. However, Eq. 1 is not a bad approximation for the average front movements.

The base-case method (mobility contrast multiplied by permeability contrast) is consistent with the original polymer flood design for the Daqing polymer flood (Wang *et al*. 2008a). The endpoint water flood mobility ratio (mobility contrast) at Daqing was given as 9.4. A number of different layers can be identified at Daqing, with a range of permeability contrasts between layers and with different circumstances of crossflow versus no crossflow. However, a permeability contrast of 4:1 (high-permeability over low-permeability) approximates much of the reservoir associated with the original polymer flood (Wang *et al*. 2008a). Then, raising the injection water viscosity by a factor of 10 should reduce the mobility ratio to unity—thereby eliminating the tendency for viscous fingers to form. Raising the polymer solution viscosity by an additional factor of 4 (i.e., to 40 total) overcomes the permeability contrast to provide the maximum vertical sweep efficiency (i.e., more like the bottom illustrations in Fig. 2 rather than the top illustration).

No Crossflow

If barriers to fluid crossflow exist, the distance of polymer penetration into less-permeable layers is substantially limited compared to the case with crossflow. Using the distance of polymer penetration into a high-permeability layer (with permeability, k_1) as a reference, the relative distance of polymer penetration into a less-permeable layer (with permeability, k_2) is approximately given by the square root of the permeability-porosity ratio, $[(k_2 \phi_1)/(k_1 \phi_2)]^{0.5}$ (Seright 1988, 2010). Consequently, polymer flooding has considerably more potential in improving oil recovery in layered reservoirs with crossflow than in those without crossflow. Seright (2010) provided an example showing diminished incentive to inject more than 10-cp polymer to displace 1000-cp polymer in a layered reservoir with no crossflow. If no crossflow occurs, a satisfactory design involves simply decreasing the mobility ratio to unity in a given layer.

Comparison with Field Designs

The seventh column of Table 1 lists a measure of how the injected polymer concentration for some recent polymer floods compares with the base-case design method. The parameter listed in this column is the injected polymer viscosity divided by the product of endpoint mobility ratio and permeability contrast. When this parameter is unity, our base-case design is achieved. Examination of Table 1 reveals one case (early Daqing) where the base-case design was achieved, one case (later Daqing) that substantially over-shot the base-case design, and numerous cases that significantly under-achieved the base-case design. For the latter, note that some engineers are overly aggressive when characterizing the heterogeneity of their reservoirs. This action will result in over-predicting the polymer viscosity needed using the base-case design. If the reservoir has no clear delineation of layers that have distinctly different permeability, it should be treated as basically one layer in our base-case method. That consideration may move some of the ″under-achieving″ designs in Table 1 closer to the base-case design. This point may be most valid for cases where the injected polymer viscosity was close to the oil viscosity. Cases that were most likely to be true ″under-achieving″ designs were those where polymer viscosity was substantially less than oil viscosity.

In the sixth column of Table 1, the permeability contrast is listed for several cases. Those values were based on literature reports where either Dykstra-Parsons coefficients of permeability variation or a range of permeabilities were provided. Given a Dykstra-Parsons coefficient (D_v), an effective permeability contrast (k_{cont}) can be calculated—i.e., $k_{cont}=2$ if $D_v=0.4$; $k_{cont}=2.5$ if $D_v=0.5$; $k_{cont}=3.5$ if $D_v=0.6$; $k_{cont}=5.1$ if $D_v=0.7$; $k_{cont}=8.8$ if $D_v=0.8$; $k_{cont}=23$ if $D_v=0.9$. As mentioned above, if engineers assign a high Dykstra-Parsons coefficient to a relatively thin strata with uncorrelated permeability variations, the base-case design over-estimates the required polymer viscosity.

Will Relative Permeability Effects Favor Use of Low Polymer Viscosities?

In the previous section, an issue was left hanging for our base-case method for determining the appropriate polymer viscosity to use. Specifically, what value should be used for the mobility contrast? Mobility is defined as permeability (k) to a given phase divided by the viscosity (μ) of that phase. An accepted part of reservoir engineering is that the efficiency of a displacement depends on the mobility ratio—i.e., the mobility of the displacing phase divided by the mobility of the displaced phase. (Craig 1971). Fig. 3 illustrates oil recovery for water displacing oil using a wide range of assumed oil viscosities (from 1 cp to 100,000 cp). These curves where generated using fractional flow calculations assuming one homogeneous layer, incompressible flow, and no density or capillary pressure differences between phases. The initial water saturation was 0.3. The relative permeability characteristics were given by Eqs. 2 and 3. The conditions given in Eq. 4 will be labeled our ″initial case.″

$$k_{rw}=k_{rwo}\,[(S_w-S_{wr})/(1-S_{or}-S_{wr})]^{nw} \tag{2}$$

$$k_{ro}=k_{roo}\,[(1-S_{or}-S_w)/(1-S_{or}-S_{wr})]^{no} \tag{3}$$

$$\text{Initial Case: } k_{rwo}=0.1,\ k_{roo}=1,\ S_{or}=0.3,\ S_{wr}=0.3,\ nw=2,\ no=2 \tag{4}$$

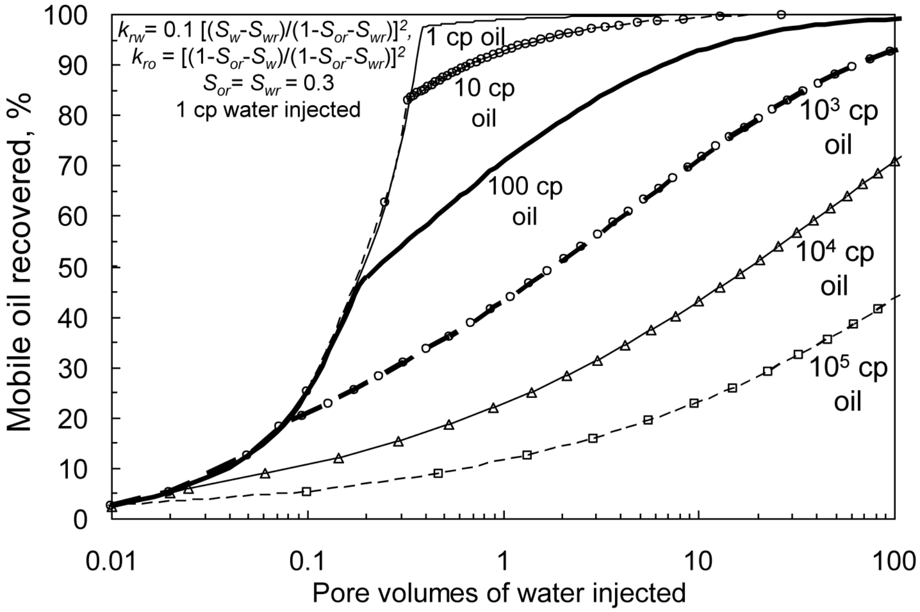

Figure 3—Fractional flow calculations for water displacing oil, one layer. Initial case.

The y-axis in Fig. 3 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, S_{or}.) At one PV of water injected, note that oil recovery increases substantially each time the mobility ratio is decreased by a factor of ten. Specifically, oil recoveries at 1 PV are 11.3%, 22.7%, 42.8%, 70.4%, 92.7%, and 99.2% for oil viscosities of 100,000-, 10,000-, 1000-, 100-, 10-, and 1-cp, respectively.

A convenient and conservative choice for the mobility contrast in our base-case polymer-viscosity-selection method above is to use the endpoint water-oil mobility ratio. However, two relative permeability arguments have been used to rationalize injection of either water or relatively low (compared to the base-case method) polymer viscosities to displace viscous oils. One argument contends that the specific relative permeability curves associated with a particular field could allow a surprisingly efficient displacement. Table 2 illustrates this point. Note for the case where the water saturation exponent (*nw*) was 20, 86% of the mobile oil was recovered after injecting only 1 PV of water to displace 1000-cp oil. In contrast, only 43% of the mobile oil was recovered when *nw*=2 (with all other parameters remaining fixed). Unfortunately, relative permeability curves are notoriously difficult to determine for viscous oils. Maini (1998) discussed the many challenges associated with their determination and use. If the water saturation exponent is assigned incorrectly high or the endpoint water relative permeability is measured too low (perhaps by insufficient water flooding during core floods), the polymer requirements could be substantially underestimated.

Table 2—Effect of water relative permeability parameters.μ_o=1000 cp, μ_w=1 cp, k_{roo}=1, *no*=2.

k_{rwo}	*nw*	Endpoint mobility ratio	Mobility ratio at shock front	Mobile oil recovery at 1 PV
0.5	2	500	1.92	27%
0.3	2	300	1.87	32%
0.1	2	100	1.80	43%
0.01	2	10	1.40	71%
0.1	5	100	2.04	64%
0.1	10	100	1.62	77%
0.1	20	100	1.14	86%

In a number of cases where relative permeability curves were obtained during water injection to displace oil with viscosity of 1000 cp or more, only 5 PV of water were injected. The laboratories performing the work assumed that since little or ″no″ additional oil was produced at 5 PV, they had reached the endpoint. Not surprisingly, they concluded that the endpoint k_{rw} (labeled k_{rwo}) was 0.05 or less, and consequently, they deemed only 25-30 cp was needed for an efficient polymer flood. Fig. 4 (based on fractional flow calculations using the parameters shown in the figure) demonstrates how the apparent endpoint value increases with water throughput, up to 1000 PV injected. In Fig. 4, the k_{rwo} is 0.0407 after 5 PV. The blue curve in Fig. 5 shows predicted recovery for a polymer flood (displacing 1000-cp oil) using 25-cp polymer, assuming that k_{rwo} is 0.0407. In contrast, the green circles in Fig. 5 demonstrate that 200-cp polymer is required to produce the same effect if the true k_{rwo} is 0.3. Consequently, assignment of a low k_{rwo} value after insufficient water throughput leads to under-designing the polymer flood.

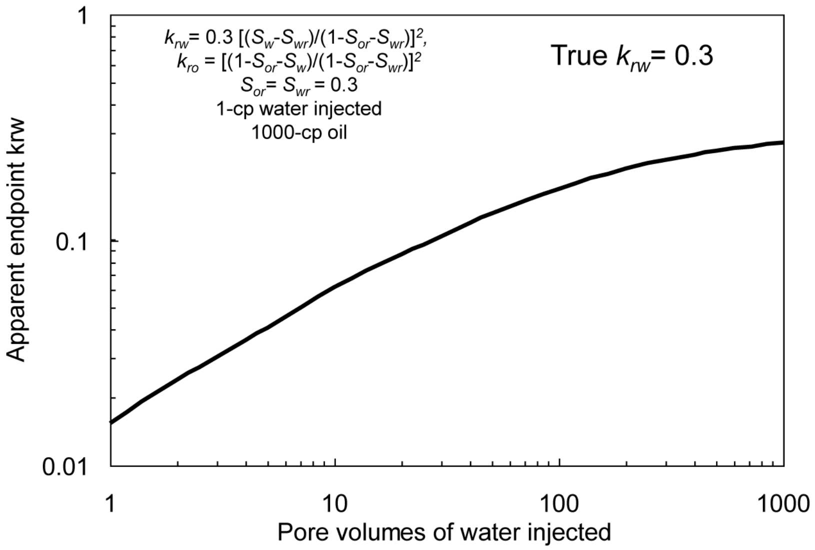

Figure 4—Insufficient throughput yields misleadingly low k_{rw} values.

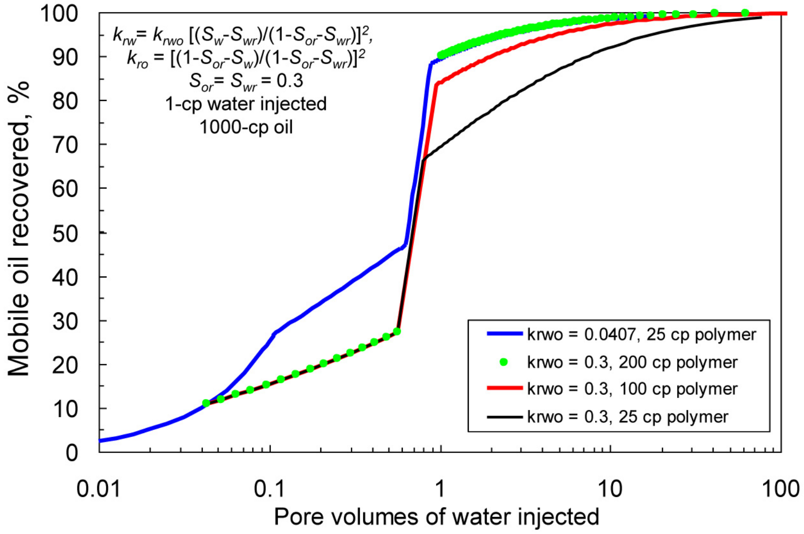

Figure 5—Fractional flow calculations of polymer flooding in a homogeneous system.

Another argument is that the mobility ratio at the shock front should be used instead of the endpoint mobility ratio to judge the efficiency of a displacement. The mobility ratio at the shock front (from fractional flow calculations) can be surprisingly favorable (low) when injecting aqueous fluids to displace viscous oils. Beliveau (2009) noted a case for the Mangala field where the endpoint mobility ratio during water injection was 14 but the mobility ratio at the shock front was only 0.94. Table 2 lists cases where the endpoint mobility ratios ranged from 7 to 260 times greater than mobility ratios at the shock front. The table lists a wide range of recovery efficiencies (at 1 PV injection) that did not correlate well with the mobility ratio at the shock front.

Viscous fingering is another phenomenon that should be considered before committing to a low-concentration polymer flood to displace viscous oil. Without consideration of viscous fingering, the pore-volume throughput (averaged over all pore space) might seem quite low, and the associated relative permeability to water might be estimated to be quite low—suggesting a modest mobility ratio. However, if the viscous finger is narrow (as would be expected with a high mobility contrast), only a small fraction of a layer thickness might be contacted. Consequently, the actual water throughput in a given section of a viscous finger and the associated water relative permeability might be radically higher than assumed using the calculated shock-front mobility ratio.

In summary, relative permeability curves can be identified that allow efficient displacement of viscous oil using water or low-viscosity polymer solutions. However, incorrect assumption of overly optimistic relative permeability and the consequent selection of low injected polymer solution viscosity can lead to early polymer breakthrough and its associated inconveniences. A low mobility ratio at the shock front does not guarantee an efficient displacement of a viscous oil. Viscous fingering may make displacements much less efficient than expectations based on shock-front mobility ratios.

Do Economics Favor Use of Low Polymer Viscosities?

When displacing viscous oils (e.g., 1000 cp), relatively high polymer viscosities (e.g., >100 cp) are normally required to achieve a favorable or piston-like displacement. However, in notable Canadian polymer floods (Delamaide *et al*. 2014) with 1000-cp oil, injected viscosities were 30 cp or less. Do economics favor use of low polymer viscosities over high polymer viscosities? For this part of the analysis, assume that injectivity and pressure limitations do not exist in the reservoir—so that focus is explicitly on the economic issue. (Injectivity and pressure limitations well be covered later.) Fig. 6 plots viscosity of a HPAM (that is commonly used commercially) versus polymer concentration in two different salinity waters. (The 2.52%-TDS brine is characteristic of that in a Canadian polymer flood, while the 0.05%-TDS brine is characteristic of that in a Suriname polymer flood.) For both water salinities, if polymer concentration is greater than 1000 ppm, viscosity (at 7.3 s^{-1}) varies with the 1.9 power of polymer concentration. This behavior economically favors use of high polymer concentrations. For example, if one wished to double the polymer solution viscosity, only 44% more polymer is required [i.e., $2^{(1/1.9)} = 1.44$].

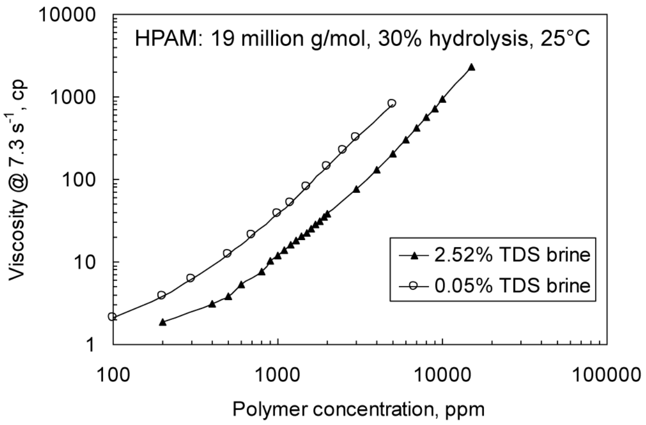

Figure 6—HPAM viscosity versus polymer concentration.

Since a finite amount of oil exists in a reservoir, injection of polymer solutions will eventually reach a point where the value of the produced oil becomes less than the costs associated with polymer injection. Does this reality favor use of low polymer viscosities and concentrations? To address this question, a simple benefit analysis was performed that focused on oil price and polymer viscosity/concentration. To determine oil recovery versus volume of polymer solution injected, fractional flow calculations were performed assuming the conditions indicated at the top of Fig. 7. (The reservoir was assumed to be at S_{wi}=0.3 at the start of polymer injection. Polymer retention and inaccessible PV were assumed to be zero.) For any given volume of polymer solution injected, the ″benefit″ was calculated as the value of the oil produced up to that time minus the cost of the polymer injected. Oil prices between $20/bbl and $100/bbl were considered, and polymer cost was fixed at $1.50/lb ($3.30/kg). The relation between polymer concentration and viscosity was taken from the higher-salinity case in Fig. 6. Of course, detailed economic analyses will normally consider many factors when planning a polymer flood, including oil price, polymer costs, labor, drilling and well-preparation costs, polymer-preparation facilities, water-source costs, flow lines to/from wells and instrumentation, produced fluid separation and treatment costs, surveillance costs, and other costs (Wang *et al*. 2008b). For simplicity of illustration of our point, assume these other costs can be reflected as a lower-than-actual oil price.

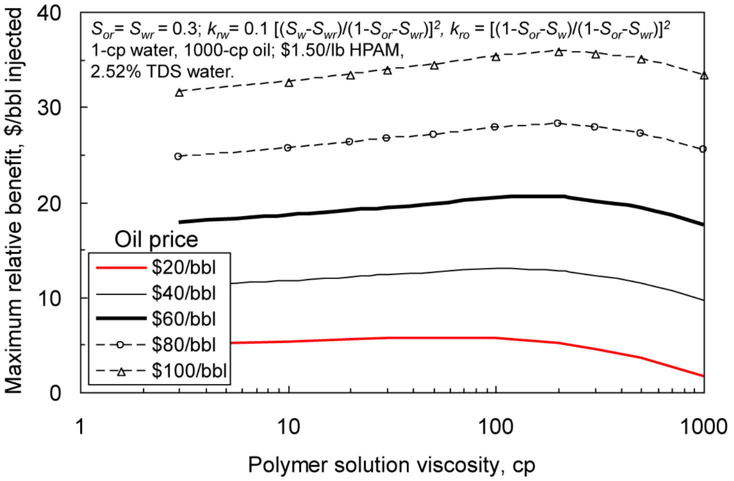

Figure 7—Benefit versus polymer viscosity: 1 homogeneous layer, 2.52%-TDS brine.

When injecting polymer solutions, profitability increases with time and volume injected up to some maximum value and then decline. Fig. 7 plots this point of maximum benefit as a function of injected polymer viscosity and oil price for a polymer flood in a homogeneous one-layer reservoir with 1000-cp oil. Two points can be taken from this figure. First, in a homogeneous system with the particular relative permeability characteristics listed in Fig. 7, the greatest benefit is associated with injection of 100-200-cp polymer solutions. Second, for a given oil price, the relative benefit was not very sensitive to injected polymer viscosity, especially at low oil prices. Fig. 8 plots the pore volume of polymer injected to achieve a given maximum relative benefit provided in Fig. 7. When using low polymer viscosities, large volumes of polymer solution must be injected to achieve the maximum benefit. In contrast, for polymer viscosities of 100 cp and above, the polymer volume associated with the peak or maximum benefit is around one PV, regardless of oil price.

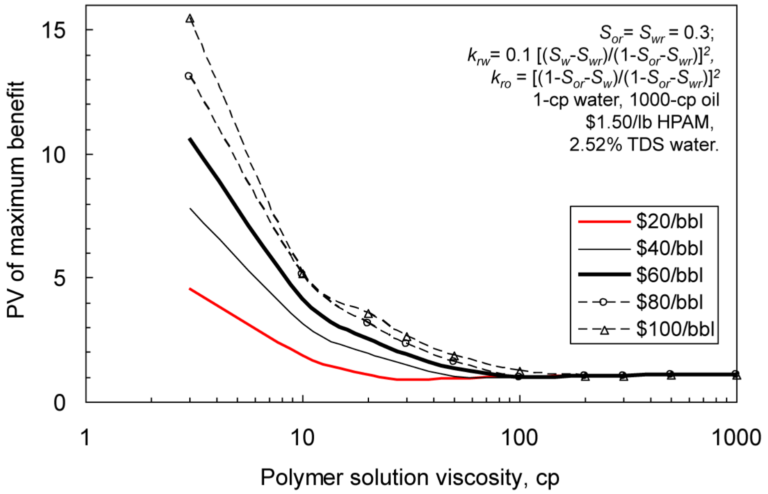

Figure 8—Pore volume (PV) injected for maximum benefit, associated with Fig. 7.

Fig. 9 (analogous to Fig. 7) considers the case where two layers (of equal thickness) are present, and fluids can freely crossflow. Layer 1 is 10 times more permeable than Layer 2. Comparing Figs. 7 and 9 confirms (1) higher financial benefits at higher polymer viscosities (up to 500 cp in this case) and (2) the maximum benefit becomes less sensitive to polymer solution viscosity as oil price decreases. The main point of this analysis is that ″economics″ do not favor injection of low-viscosity polymer solutions when displacing viscous oils. Justifying a preference for using low-viscosity polymer solutions requires some other factor, such as injectivity considerations or imposed pressure constraints. These other factors will be considered shortly.

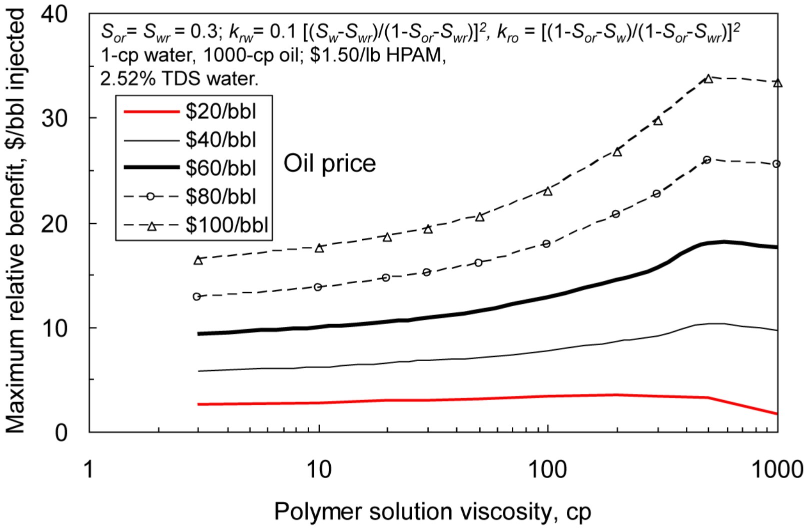

Figure 9—Benefit versus polymer viscosity: 2 layers, free crossflow, $k_1=10k_2$, $h_1=h_2$.

Some Improvement in Mobility Ratio is Better than None

Given caveats, this argument is difficult to dispute. Examination of Fig. 3 reveals that decreasing the mobility ratio by a factor of 10 to 30 will substantially increase sweep efficiency even for very viscous oils. However, that observation must be tempered with two other facts. First, a significant capital outlay must be made for water treatment and polymer preparation facilities when upgrading from water flooding to polymer flooding, regardless of the polymer concentration chosen. The cost of facilities for a high-polymer concentration flood are not greatly different than for a low-concentration polymer flood (Wang *et al*. 2011, Thomas *et al*. 2015). Second, when displacing viscous oils, low-viscosity polymer floods will experience viscous fingering and earlier polymer breakthrough than high-viscosity polymer floods. Consequently, low-viscosity polymer floods must deal with the problems of produced polymer earlier than high-viscosity polymer floods. (This statement assumes that fractures do not cause severe inter-well channeling. The fracture-channeling issue will be considered shortly.)

Do High Resistance Factors and Residual Resistance Factors Reduce the Need for High Polymer Viscosities and Volumes?

Resistance Factors

Resistance factor is defined as brine mobility (λ or k/μ) divided by polymer mobility in porous media. Early researchers (Pye 1964, Smith 1970, Jennings *et al*. 1971, Hirasaki and Pope 1974) recognized that high molecular weight HPAM sometimes reduced the mobility of aqueous solutions during laboratory experiments in porous media by a greater factor than can be rationalized based on the viscosity (μ) 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. This effect was touted to be of great benefit (Pye 1964, Jennings *et al*. 1971) for polymer flooding because the polymer appeared to provide significantly more apparent viscosity (i.e., resistance factor) in porous media than expected from normal viscosity measurements. This effect was normally achieved using short cores and gently handled HPAM solutions. Unfortunately, these benefits were often not achievable in field applications because normal field handling and flow through an injection sand face at high velocities mechanically degraded the large molecules that were responsible for the permeability reduction (Seright *et al*. 1981, Seright 1983, Seright *et al*. 2011). Also, the largest molecules were preferentially retained (i.e., by mechanical entrapment in pores) and stripped from the polymer solution before penetrating deep into the formation (Seright *et al*. 2011). Consequently, in rock with moderate to high permeability (>200 md), one cannot expect low-velocity resistance factors of conventional polymers (i.e., HPAM or xanthan) to be substantially greater than (i.e., >2 times) the value expected from viscosity measurements (Seright *et al*. 2011). A conservative approach to polymer flood design would assume that low-velocity resistance factor factors track low-shear-rate viscosities.

Residual Resistance Factors

Residual resistance factor is defined as water mobility before polymer injection divided by water mobility during water injection after a polymer flood. This parameter can be thought of as the permeability reduction provided by the polymer. If the residual resistance factor is one, no permeability reduction is caused by the polymer. In that case, the mobility ratio can be high during water injection after polymer, and severe viscous fingering can occur. Consequently, a large polymer bank must be injected. As the residual resistance factor increases, the mobility contrast decreases when water follows polymer injection, and greater sweep efficiency can be maintained. At the extreme, if the residual resistance factor has about the same value as the resistance factor, a relatively small polymer bank can be injected (i.e., just enough to satisfy polymer retention).

Displacements with high mobility ratios require many pore volumes of throughput to reach the final saturation state. If insufficient water is injected, residual resistance factors will be artificially high. Oddly, literature reports rarely specify how many pore volumes of water were flushed to reach the stated residual resistance factor. Fig. 10 plots residual resistance factors (versus initial permeability of the porous medium) that were reported in the literature. Many authors reported residual resistance factors without specifying brine throughput: (1) Jennings *et al*. (1970) [24 HPAM values ranging from 2-11], (2) Szabo

(1972) [5 HPAM values ranging from 1.2 to 2.4], (3) Hirasaki and Pope (1974) [8 Pusher 700 HPAM values ranging from 1.3 to 5], (4) Vela *et al.* (1976) [7 Pusher 700 HPAM values ranging from 1.2 to 48], (5) Duda *et al*. (1983) [over 60 HPAM and xanthan values ranging from 1.1 to 7, (6) Chauveteau (1981) [2 HPAM values from 1.2 to 2], (7) Zaitoun and Kohler (1987) [4 xanthan solutions values from 1 to 2.5], (8) Ramazani *et al*. (2010) [24 HPAM values from 1.2 to 8.7], and (9) Stavland *et al*. (2010) [28 HPAM values from 1.0 to 7].

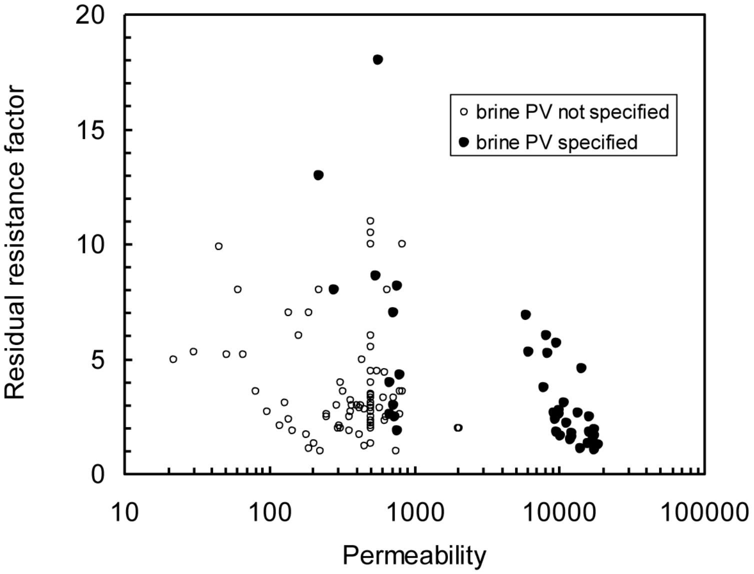

Figure 10—Literature residual resistance factors versus permeability.

Dabbous (1977) reported 10 Pusher 500 and 700 HPAM residual resistance factors (ranging from 1.0 to 18) in which he did specify brine throughput values. As expected, residual resistance factor generally decreased with increased throughput, although some odd exceptions were noted. Chauveteau and Kohler (1974) observed a residual resistance factor of 2.5 after 8 PV of brine, following a 5.3-cp Pusher 500 HPAM bank. Dey and Baijal (1978) reported residual resistance factors from 1.06 to 13 after ″several PV″ of brine after HPAM banks.

Large variations in residual resistance factors were seen in literature data. Several factors may be responsible for these large variations. First, core-to-core mineralogy variations may cause part of the scatter, since permeability reduction may depend on polymer adsorption and polymer adsorption depends strongly on mineralogy (especially clay and iron content). A second, major reason for the scatter is probably that insufficient brine was injected to drive the core to a true residual resistance factor. Only two cases in the literature reported flushing the core with more than 10 PV of brine. Exactly how much brine should be injected for a given core remains to be established.

For adsorbed polymers, resistance factors (F_r, apparent viscosities in porous media relative to brine) and residual resistance factors (F_{rr}, permeability reduction values) can increase with decreasing permeability, especially below 100 md (Pye 1964, Jennings *et al*. 1971, Hirasaki and Pope 1974, Vela *et al.* 1976, Jewett and Schurz 1979, Duda *et al*. 1983, Zaitoun and Kohler 1987, Rousseau *et al*. 2005). In other words, these polymers can reduce the flow capacity of low permeability rock by a greater factor than high permeability rock. Depending on the magnitude of this effect, vertical flow profiles can be harmed, even though the polymer penetrates significantly farther into the high permeability rock (Seright 1988, Liang *et al*. 1993, Zhang and Seright 2007, Seright 2010).

How Much Brine Must be Flushed to Reach a Stabilized Residual Resistance Factor?

A core experiment was performed to monitor residual resistance factors as a function of PV throughput. The Dundee sandstone core was 122-cm long and 3.81×3.81-cm^2 in cross-section, with a porosity of 0.203 and pore volume of 358.8 cm^3. The core had four internal pressure taps that divided the core into five 24.4-cm long sections. After saturating the core with brine (2.52% TDS), 10 PV (3.6 liters) of 1000-ppm SNF Flopaam 3830S in 2.52% TDS brine was injected at a velocity of 2.1 ft/d. This solution had a viscosity of 10.1 cp at 7.3 s^{-1}, 25°C. Subsequently, 100 PV of brine (2.52% TDS) was injected, while monitoring the residual resistance factor in the middle three core sections (73-cm in length). The results are shown in Fig. 11. This figure reveals that residual resistance factors were still decreasing after injecting 100 PV of brine. The final value after 100 PV was 2.2.

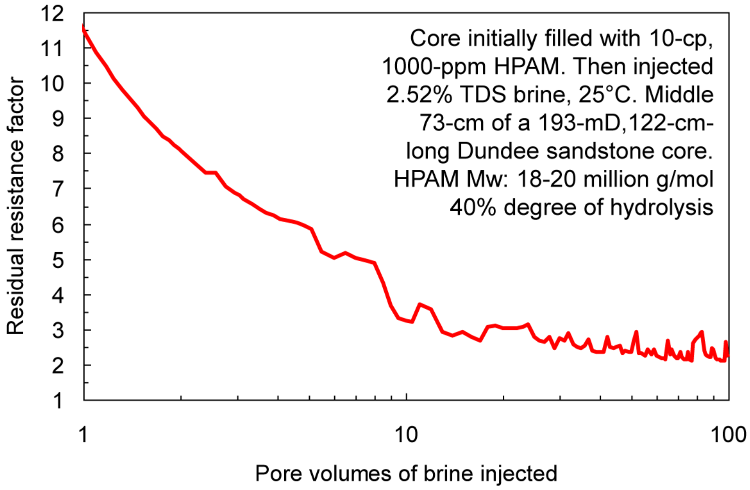

Figure 11—Residual resistance factor versus brine throughput.

Summary

An important point from our videos at http://baervan.nmt.edu/randy/ and from polymer flooding experience over the past 50 years is that the polymer bank should be as large as practical (Sheng *et al*. 2015). Once brine inject begins, viscous fingering and heterogeneities will quickly lead to severe channeling (Cyr *et al*. 1988, Sorbie and Seright 1992). Many residual resistance factors that have been reported in the literature (for permeability above 200 md) are probably too high because not enough brine was injected to displace the mobile polymer or because non-propagating high-molecular-weight polymer species caused artificially high resistance to flow during short core experiments. Thus, accepting high experimental residual resistance factors without caution may lead to not injecting a large enough polymer bank or a high enough polymer concentration in the polymer bank. To be conservative during the design of a polymer flood, residual resistance factors should be assumed to be unity, unless reservoir permeability is low (<200 md).

A Rheological Effect during Unfavorable Displacements

If the base-case design method is used to select the polymer solution viscosity, oil displacement will be efficient and the rheology of the polymer solution will have virtually no impact on sweep efficiency (Seright 1991a, Seright 2010). However, rheology of the polymer solutions can affect sweep efficiency if polymer solution viscosity is less than optimum. To explain, first consider the rheology in porous media of HPAM solutions, as shown in Fig. 12. Depending on HPAM concentration, molecular weight, and salinity, these solutions show Newtonian (flow-rate independent) or flow-thinning (shear-thinning, where resistance factors decrease reversibly with increasing fluid velocity) behavior at low velocities, flow-thickening (shear-thickening or pseudo-dilatant, where resistance factors increase reversibly with increasing velocity) behavior at intermediate velocities, and mechanical degradation at high velocities (where resistance factors decrease irreversibly with increased velocity). (The later behavior is not shown in Fig. 12.) Velocities above 10 ft/d are confined to the near wellbore region. The vast majority of oil will be displaced far away from the wellbore, where flux values are low (1 ft/d or less).

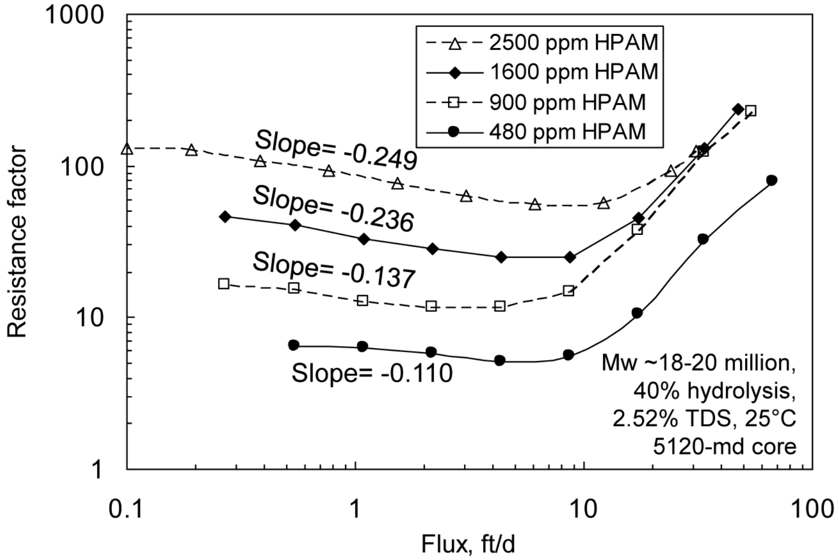

Figure 12—Rheology in porous media for a commercial HPAM.

In Fig. 1, consider the region where polymer exists in both layers. If the mobility ratio is low, little mobile oil will remain in this region after the polymer front passes. However, if the mobility ratio is above one, considerable mobile oil may remain in the polymer-contacted region, depending on exactly how high the mobility ratio is. If fluids can freely crossflow between the two layers, the ratio of velocities for the two layers in the polymer filled region will be given by Eq. 5.

$$v_2 / v_1 = (k_2/k_1)(\phi_1/\phi_2)(Fr_2/Fr_1) \tag{5}$$

If the resistance factors in the two layers can be described by the power-law equation, and the Blake-Kozeny equation applies, Eq. 6 describes resistance factor versus velocity, permeability, and porosity.

$$Fr \approx (v\phi)^{(n-1)}\ (k/\phi)^{(n-1)/2} \tag{6}$$

Where (n-1) is the slope of the flow-thinning region in Fig. 12. Eqs. 5 and 6 can be combined to form Eq. 7.

$$v_2 / v_1 \approx [(k_2\ \phi_2/(k_1\ \phi_1)]^{(1+n)/(2n)} \tag{7}$$

Table 3 provides velocity ratios (v_2/v_1) in the polymer-contacted region for various permeability ratios (assuming porosity is fixed). This table reveals that flow thinning (shear thinning) slows the velocity in the less-permeable layer. This effect is modest if the permeability contrast is low and the slope of flow-thinning region is low (as in Fig. 12). However, the effect is quite significant for high slopes and high permeability contrasts. By slowing the velocity in the less-permeable layer, the aqueous throughput is reduced through that layer. If the polymer/oil mobility ratio was favorable (less than one), this phenomenon is of little consequence since most mobile oil was displaced when the polymer front passed through.

However, if the mobility ratio was greater than one, oil displacement may be slowed considerably for the mobile oil that remains in the less-permeable layer behind the polymer front. This observation argues in favor of polymer viscosities that are high enough to provide a favorable mobility ratio, especially when high permeability contrasts exist.

Table 3—v_2/v_1 values in the polymer-contacted region.

(n-1)	k_1/k_2=2	k_1/k_2=4	k_1/k_2=10	k_1/k_2=20
0	0.500	0.250	0.100	0.050
-0.110	0.479	0.229	0.087	0.042
-0.137	0.473	0.224	0.083	0.039
-0.236	0.449	0.202	0.070	0.031
-0.249	0.446	0.199	0.068	0.030
-0.5	0.354	0.125	0.032	0.011
-0.7	0.223	0.050	0.007	0.002

Is Injectivity Impaired by Viscous Polymer Solutions?

In wells that are not fractured, injection of viscous polymer solutions will necessarily decrease injectivity—roughly in proportion to the viscosity of the fluid injected (Wang *et al*. 2008, Seright *et al*. 2009, Manichand *et al*. 2013). If injectors are horizontal, economic polymer injection rates can be attained without injecting above the formation parting pressure (Taber and Seright 1992, Delamaide *et al*. 2014). However, if wells are vertical, injectivity losses (relative to water injectivity) are usually prohibitive during polymer injection unless fractures or fracture-like features are open (Van den Hoek *et al*. 2009, Khodaverdian *et al*. 2009, Manichand *et al*. 2013).

Injection above the formation parting pressure and fracture extension is not necessarily detrimental. Under the proper circumstances it can increase fluid injectivity, oil productivity, and reservoir sweep efficiency (Crawford and Collins 1954, Dyes *et al*. 1958, Wang *et al*. 2008a). Fractures can also reduce the risk of mechanical degradation for polyacrylamide solutions (Trantham *et al.* 1980, Wang *et al*. 2008, Seright *et al*. 2009, Zuchner *et al*. 2015). The key is to understand the degree of fracture extension for a given set of injection conditions so that fractures do not extend out of the target zone or cause severe channeling.

Previous work (Gadde and Sharma 2001, Seright *et al*. 2009) indicates that once fractures are opened, the fracture area increases to accommodate increased injection rate or increased injectant viscosity—with small increases in downhole pressure. Saripalli *et al*. (1999) and Gadde and Sharma (2001) considered fracture growth as a function of particle plugging and other effects. Their work demonstrated that particle plugging during injection at a fixed rate leads to fracture extension. As a portion of the fracture face becomes impaired by plugging, pressure at the fracture tip forces the fracture to extend until enough fracture area is available to accommodate the existing injection rate. Consequently, injectivity observed for a well [i.e., injection rate divided by (flowing pressure minus static pressure)] may not appear to be sensitive to volume of particles injected (Schmidt *et al*. 1999). Similarly, when injecting viscous polymer solutions, fracture extension explains why injectivity often appears to be not greatly different than that during water injection (Wang *et al*. 2008, Manichand *et al*. 2013).

Manichand *et al*. (2013) performed calculations to estimate the fracture area open to flow during polymer injection into a vertical well in the Tambaredjo field (Suriname). Given the depth of the Tambaredgo formation (1000 ft) and the local stress field, induced fractures are horizontal. In their case, polymer solution injectivity was 61 times greater than expected for injection into an open-hole completion, and the fracture area was roughly 61 times greater than that associated with the open hole. This area equated to a fracture that extended radially 20 ft from the well. This short fracture did not jeopardize sweep (i.e., create severe channeling) since the nearest production well was over 300 ft away (Moe Soe Let *et al*. 2012). However, the fracture tremendously increases injectivity for the polymer solution. The fracture also reduced the possibility of HPAM mechanical degradation. By increasing the sandface area by a factor of 61, the velocity when the polymer enters the formation is reduced in proportion.

Will Injection Above the Formation Parting Pressure Compromise Reservoir Containment?

If injection of viscous polymer solutions opens fractures that cut through the upper or lower formations, that would provide a good reason not inject using high polymer concentrations or rates. De Pater (2015) recently reviewed issues associated with reservoir containment during fracture growth. He noted that growth of fracture height is complex and not entirely understood. However, in general, growth of fracture height has been less than predicted during simulations. The rate and extent of fracture-height growth is specific to the formation. Some of the greatest ratios of fracture length to fracture height have been observed in soft formations such as those in western Canada (80:1 in some cases). These are the same types of formations where polymer flooding has been applied to displace viscous oils—thus providing hope that the cap rock will not be breached during injection of viscous polymer solutions. Even so, the actual pressure which these formations can withstand must be determined experimentally. Consequently, the most appropriate time to assess the maximum polymer viscosity and injection rate for a formation is during a polymer flood pilot project in a given field.

Zhou *et al*. (2010) experimentally examined shear dilation and fracture growth during polymer injection in unconsolidated sands. They concluded that injection pressure should exceed the minimum stress by a factor of 2.5 to induce fracture propagation. They also concluded that fracture initiation was only a function of pressure, irrespective of the injection fluid viscosity. Also, induced fractures were dominantly planar, although they were tortuous. Matrix permeability enhancements up to 40% were observed due to shear dilation.

In the Daqing oilfield in China (in ~5600 injection wells, 500-800-md rock, 9-cp oil), injectivities were only 10% lower using 150-300-cp polymer solutions compared with 40-50-cp polymer solutions (Wang *et al*. 2011). This observation is consistent with fracture extension when injecting viscous polymer solutions. Interestingly, no problems were reported of fractures compromising the reservoir seals or causing severe channeling during this large-scale project (Han 2015).

Will a Fracture Extend Too Far and Compromise Sweep Efficiency?

Parallel Vertical Fractures

The existence of a fracture near an injection well can dramatically increase polymer injectivity and reduce mechanical degradation (Trantham *et al*. 1980, Seright 1983, Seright *et al*. 2009, Zuchner *et al*. 2015). Of course, if fractures extend too far in the wrong direction, they can compromise sweep efficiency (Crawford and Collins 1954, Dyes *et al*. 1958, Bargas and Yanosik 1988). The key questions are (1) how far is too far and (2) what degree of injectivity improvement will be realized as a function of fracture length? Some simple concepts help appreciate the impact of fractures. First, if vertical fractures in vertical injection wells run parallel to fractures that intersect offset vertical production wells, a line drive is formed, which is ideal for sweep efficiency—effectively making parallel horizontal wells. This fact argues strongly for understanding the direction and orientation of fractures before commencing a polymer flood (or any other injection process). Most of the concerns about fracture extension could be mitigated if the field is drilled to take advantage of fracture direction and orientation. Even if the fractures connect from injector to injector, sweep toward the production wells should not be compromised. However, keeping vertical fractures open in injection wells is easier than in production wells. If fractures are open in injection wells but closed in production wells, oil could be driven past or away from the production wells if pressures in the pattern are not balanced well.

Horizontal Fracture in a Vertical Well

The Sarah Maria polymer pilot project in Suriname is believed to have horizontal fractures that are open during polymer injection into their vertical wells (Moe Soe Let *et al*. 2012, Manichand *et al*. 2013, Manichand and Seright 2014). For this type of case, some simple calculations can be made to estimate polymer injectivity and fracture extension. From one viewpoint, injectivity should be proportional to or closely related to the area available. For an open-hole completion, the area open to flow is $2\pi r_w h$, where r_w is wellbore radius and h is formation height. If a horizontal fracture opens radially from the well, the added fracture area is $2\ \pi\ (r_f)^2$, where r_f is the radius of the horizontal fracture. (Recall that there are upper and lower faces associated with a horizontal fracture.) If formation height is 30 ft and wellbore radius is 0.5 ft, the area for an open hole is 94 ft^2. If a horizontal fracture extends 30 ft radially from the wellbore, the added fracture area is 5655 ft^2—60 times greater than the open-hole area. In this particular case, this area of 5655 ft^2 also corresponds to the area associated with an open-hole wellbore that was 30 ft in radius. In the general case, the increase in effective flow area will be less than the smaller of $2\ \pi\ (r_f)^2$ and $2\ \pi\ (r_f)\ h$. Increasing the flow area to 100 times and 200 times the original open hole area will require fracture extension at least to 50 ft and 100 ft, respectively. Thinner formations will result in risk of longer fracture extension. For the Suriname project (which typically has injector-producer distances around 300 ft), efforts are being conducted to assess whether fracture extension compromises sweep efficiency when injecting viscous polymer solutions (up to 165 cp) and at various rates.

Vertical Fracture (in a Vertical Injector) Pointed at a Production Well

This section considers the case where vertical fractures are pointed directly at a production well. Dyes *et al*. (1958) argued that even with mobility ratios as high as three, these fractures would have little effect on sweep efficiency if they extended half way (or less) to the offset production well. Bargas and Yanosik (1988) examined cases where a fracture extended one-quarter of the pattern distance from an injection well and one-quarter of the pattern distance from a production well. When the injector fractures pointed at the producer fractures, they found little effect on sweep efficiency if the mobility ratio was unity. However, as the mobility ratio increased to 10, sweep efficiency was significantly compromised. This finding re-emphasizes that the well pattern should be chosen to that fractures are oriented to form a line drive (as much as possible). The finding also means that if fractures are not oriented favorably, there will be a balance between improving mobility ratio through increasing injected polymer solution viscosity and harming sweep by extending fractures too far (when injecting very viscous polymer solutions).

In considering the fracture area as a function of fracture length, assume that a vertical fracture has two wings, with two fracture faces for each wing. Then the fracture area open to flow would be $4\ L_f h$, where L_f is the length of one fracture wing. Figs. 13 and 14 illustrate the trade-off between fracture length (to improve polymer injectivity) and improved mobility ratio. Fig. 13 applies to a single homogeneous layer. Fig. 14 applies to a two-layer reservoir with free crossflow between layers. (Both layers have the same thickness but one layer is ten times more permeable than the other. The fracture extends the same distance in both layers.) Both figures assume 1000-cp oil, a five-spot pattern, the fracture in the injection well is pointed directly at the production well, and all oil within one fracture radius of the injector is bypassed. The pattern is initially at connate water saturation (i.e., $S_{wr}=0.3$), and the relative permeability parameters are given by Eqs. 2-4. The x-axis plots the fracture length relative to the total direct-line distance between the injector and producer. The y-axis plots fraction of the original mobile oil in the pattern that is recovered after 1 PV of polymer injection. This fraction is given by the macroscopic displacement efficiency times the areal sweep efficiency times the volumetric sweep efficiency. Macroscopic sweep efficiency at 1 PV was determined from fractional flow calculations (like those in Fig. 3). Areal sweep efficiency was determined using the Craig-Geffen-Morse equation (Craig 1971). Vertical sweep efficiency for Fig. 14 was determined using Eq. 1. (Vertical sweep was unity for Fig. 13, since there is one homogenous layer.)

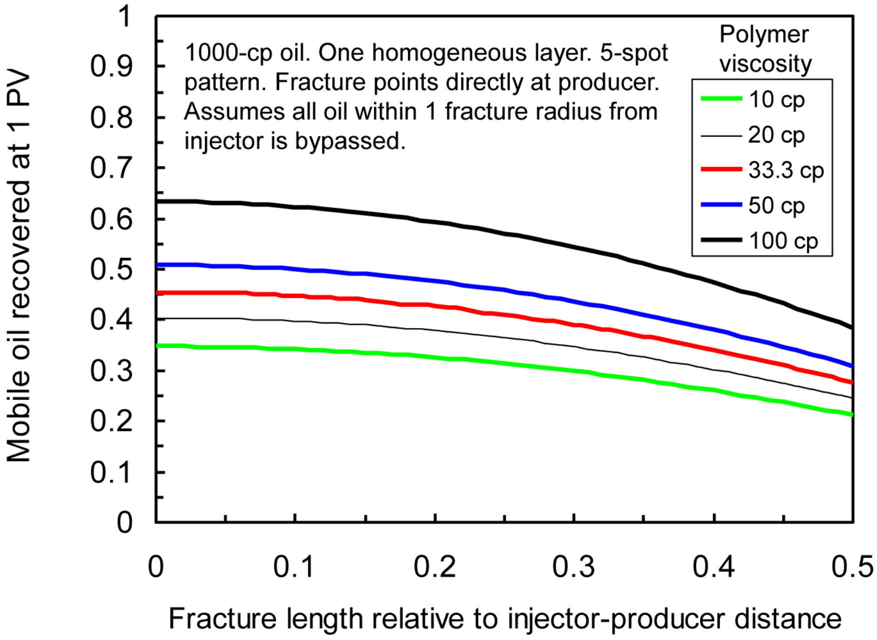

Figure 13—Effect of fracture length on sweep: One homogeneous layer.

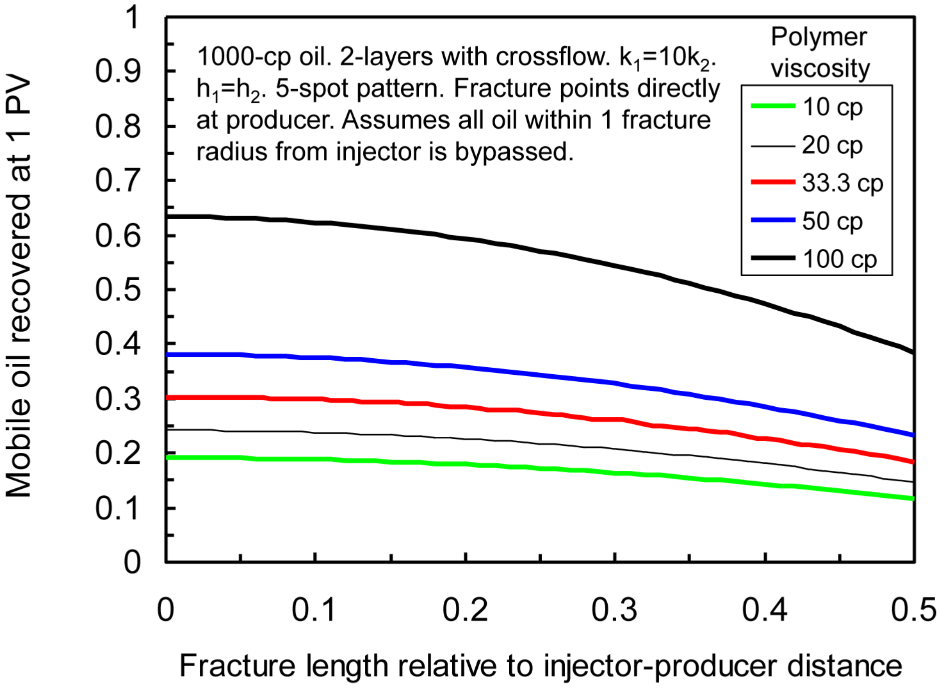

Figure 14—Effect of fracture length on sweep: Two layers, free crossflow.

Consistent with the work of Dyes *et al*., fractures do not have a major impact on sweep efficiency until the fracture extends beyond one-third the inter-well distance. The key point from Figs. 13 and 14 is that the benefit from an improved mobility ratio outweighs the sweep efficiency loss from the fracture, so long as the fracture is not too long. For example, in Fig. 13, note that increasing the fracture length from 0 to

30% (of the total distance) decreased oil recovery from 0.63 to 0.53 (with 100-cp polymer), while increasing the injected polymer viscosity from 10 to 100 cp increased oil recovery from 0.30 to 0.54 (for fractional fracture length of 0.3). The benefit from increasing polymer viscosity is greater for Fig. 14: Increasing the fracture length from 0 to 30% (of the total distance) decreased oil recovery from 0.63 to 0.53 (with 100-cp polymer), while increasing the injected polymer viscosity from 10 to 100 cp increased oil recovery from 0.16 to 0.54 (for fractional fracture length of 0.3).

For a polymer flood in the Matzen Field in Austria, Zechner *et al*. (2015) simulated that vertical fractures only extended 43 ft from the injection well (whereas well spacing was 650-1000 ft).

Note is made of the findings of Lee *et al*. (2011) that sweep could be compromised if a fracture grows in one layer but not in adjacent oil-bearing layers. However, one must question how often this situation actually occurs for polymer floods in high-permeability unconsolidated formations.

Distinguishing Between Channeling through a Fracture versus Viscous Fingering

An important dilemma exists. If excessive fracture extension causes severe channeling, injected polymer viscosities and/or rates should be reduced. In contrast, if channeling through fractures is not a problem but viscous fingering compromises sweep efficiency, injected polymer viscosities should be increased. When early polymer breakthrough occurs, how can we distinguish whether fractures or viscous fingers are primarily responsible? Kurina (2014) examined this issue and found that fluid transit time through fractures is typically at least an order of magnitude faster than transit through a viscous finger. To appreciate this fact, consider a 1-mm-wide, 30-ft-high vertical fracture that leads between an injector and a producer that are 500 ft apart. With a 50-cp tracer and 500-psi pressure drop, the tracer should transit the fracture in about 1 hour (see spreadsheet at http://baervan.nmt.edu/groups/res-sweep/gel-treatments/). The volume of this fracture is only 8.8 bbl. In contrast, consider a ″viscous finger″ that is effectively a pipe-shaped sand body that is 1 foot in diameter and 500 ft long, with a permeability of 10 darcys and a porosity of 0.3 and an S_{or} of 0.3. This ″viscous finger″ has an aqueous pore volume of 14.7 bbl. But with the same imposed pressure drop of 500 psi, the 50-cp tracer transit time would be 83 days. Put another way, flow through fractures happens much faster than flow through porous sand (as in the viscous finger). If a fracture extends part way from an injector towards a producer, a tracer will transit rapidly through the fracture and transit through the porous sand or rock in proportion to its length. So in the example above, if a fracture extended 250 ft, followed by a 250-ft-long ″viscous finger″, the tracer transit time would still be 41.5 days (i.e., substantially longer than if the fracture extended the entire distance from the injector to the producer).

If an inter-well tracer study is performed before polymer injection has started, fractures may not be open or may not extend very far. The length of a fracture may depend on how long polymer has been injected. Consequently, a diagnostic inter-well tracer study may be desirable at one or more intermediate times during a polymer flood. During these studies, the tracer formulation must have the same viscosity as the most recently injected polymer solution. If a low-viscosity tracer solution is injected, it may finger unreasonably rapidly through high-permeability paths.

Should Polymer Solutions Be More Viscous than the Base-Case Design?

To this point, consideration was given primarily to arguments advocating use of polymer solutions that are less viscous than our base-case design. Now, consider arguments advocating use of more viscous polymer solutions than the base-case design. These arguments stem from a belief that viscous solutions of very high molecular-weight HPAMs will drive the residual oil saturation below the level that can be achieved during a water flood or a conventional polymer flood. Views differ on what causes this phenomenon—and whether or not it truly occurs.

Conventional wisdom within the petroleum industry is that the ultimate residual oil saturation (S_{or}) for a polymer flood is the same as that for a waterflood (Taber 1969, Lake 1989). Polymers have a negligible effect on oil-water interfacial tension, so no reduction of S_{or} is expected, compared with waterflooding. Several previous literature reports are consistent with this view in water-wet cores, especially with Berea and Bentheim sandstone (Schneider and Owens 1982, Pusch *et al*. 1987, Wreath 1989).

However, for conditions associated with the Daqing reservoir, researchers (Wang *et al*. 2000, 2001a, 2001b, Xia et al. 2004, Wu *et al*. 2007, Wang *et al*. 2010, Wang *et al*. 2011) argued that HPAM solutions reduced S_{or} by 6 to 15 saturation percentage points, even with waterfloods and polymer floods conducted at the same constant capillary number. Notably, Wu *et al*. (2007) observed that HPAM polymers reduced the waterflood S_{or} by up to 15 saturation percentage points (i.e., a S_{or} of 36.8% with waterflooding versus 21.75% for polymer flooding) using a constant capillary number of 5×10^{-5}. The Daqing researchers observed reductions in S_{or} under oil-wet, weakly oil-wet, and mixed-wet conditions. They attributed the reduction in oil saturation to the viscoelasticity of high molecular-weight HPAM solutions—particularly associated with a polymer solution's normal stress difference. They did not observe the effect with Newtonian glycerin solutions. Ironically, the Daqing researchers reported reductions in S_{or} to about the same extent at low velocities in porous media as at high velocities (Wu *et al*. 2007, Wang *et al*. 2010). This result seems inconsistent with their proposed explanation, since viscoelasticity and normal stress differences vanish at low velocities. Conceivably, wettability alteration by HPAM may be partly responsible for this effect.

Wang *et al*. (2011) reported injecting 150-300-cp HPAM solutions (HPAM *Mw*: 20-35 million g/mol) into over 5600 wells to displace 9-cp oil from 500-800-md rock. They report incremental oil recoveries of about 20% OOIP—double that for conventional their conventional polymer flood (using 40-50-cp polymer) and about the same recovery as for ASP flooding.

Others have reported reductions in S_{or} during polymer flooding in cores that were not water wet. Schneider and Owens (1982) found that HPAM floods resulted in 1-6% reductions in S_{or} in Berea that was treated with diesel oil to make the core oil wet. They found that HPAM floods caused 6.5-8.4% reductions in S_{or} in Tensleep and Berea cores that were treated with ″Surfasil″ to induce oil-wettability.

Interestingly, reports also exist where polymer floods reportedly reduced S_{or} in water-wet cores. Zaitoun and Kohler (1987, 1988) observed that a nonionic polyacrylamide reduced S_{or} by 3% in water-wet Berea and Vosges sandstones. In Bentheim sandstone, Pusch *et al*. (1987) reported 1% to 4% reductions in S_{or} with xanthan and a Newtonian viscous sugar solution. These observations may have been within experimental error of the S_{or} determinations.

Huh and Pope (2008) performed studies in water-wet Berea and Antolini sandstone cores. Their work indicated that HPAM solutions would not significantly reduce S_{or} in a homogeneous water-wet core that had previously been waterflooded to residual oil saturation. However, they also noted that when polymer flooding in a secondary-recovery mode (i.e., when the core had a high oil saturation at the start of the polymer flood), the S_{or} reached was notably less than for a waterflood. This effect was attributed to the ability of the polymer to maintain longer oil ganglia and more effective pore drainage before snap-off and trapping of residual oil.

For heterogeneous cores, two effects could appear to make the S_{or} lower after a polymer flood than after a waterflood. First, if insufficient water is flushed through the core to displace mobile oil from less-permeable pathways, one could be misled by the high water cut to believe that the core was near S_{or}. Improved volumetric sweep during a subsequent polymer flood could rapidly produce a small spike of mobile oil from the less-permeable pathways. Huh and Pope envisioned a second means by which a polymer flood could reduce S_{or} from a heterogeneous core—that is the case where high-permeability pathways have been effectively flushed with water at the start of polymer injection, but the mobile oil saturation remains high in less-permeable pathways. In the high-permeability pathways, the final S_{or} from polymer flooding would be no different from that for the waterflood. However, in the less-permeable pathways, polymer flooding could drive the S_{or} to a lower value via the same mechanism mentioned at the end of the previous paragraph. During polymer flooding, Huh and Pope (2008) observed S_{or} reductions (relative to waterflooding) ranging from 2 to 22 saturation percentage points using heterogeneous Antolini cores and a constant capillary number of 4×10^{-6}.

Seright (2011) observed that injection of a 10-cp HPAM solution (at a fixed capillary number of 1.77×10^{-5}) to displace 190-cp crude from a hydrophobic core reduced S_{or} by 4-6 saturation percentage points, compared with waterflooding. In contrast, Vermolen *et al*. (2014) observed no significant reduction in S_{or} when polymer flooding a 300-cp oil, but saw noticeable S_{or} reductions when polymer flooding with high-molecular-weight HPAMs to displace a 9-cp oil.

Clarke *et al*. (2015) presented evidence that reductions in S_{or} by polymer flooding are associated with ″elastic turbulence″ exhibited by high-molecular-weight HPAM polymers. These phenomena occur during the ″shear-thickening″ or ″flow-thickening″ observed by HPAM polymer solutions at moderate-to-high velocities in porous media (where resistance factor increases with increased fluid velocity).

Most investigators (Wang *et al*. 2010, Urbissinova *et al*. 2010, Vermolen *et al*. 2014, Clarke *et al*. 2015) tie reductions in S_{or} to the viscoelastic character of high-*Mw* polymer solutions. If this view is accepted, polymer reduction of S_{or} should only occur at relatively high velocities. Note in Fig. 12 that the viscoelastic behavior only becomes evident above 10 ft/d for 18-20-million-g/mol HPAM in a 5120-md core. The onset of viscoelastic behavior occurs at lower velocities for less-permeable cores and higher-*Mw* polymers (Seright *et al*. 2011, Vermolen *et al*. 2014, Clarke *et al*. 2015). Concern is raised whether significant reductions in S_{or} can be expected at the very low velocities present deep in the reservoir where the majority of the oil exists. As an unexplained exception, significant reductions in S_{or} were reported at low velocities associated with the Daqing field (Fig. 21 of Wang *et al*. 2010 and Wang *et al*. 2011). In view of the state of the art for this area, extensive experimentation is needed to demonstrate whether viscous high-*Mw* polymer solutions can provide a significant reduction in S_{or} for a given field application.

When Should Polymer Injection Be Reduced or Stopped?

This question is dominantly an economic issue. However before addressing economics, some technical misconceptions and issues should be discussed.

Technical Considerations

As mentioned earlier, some authors reported that polymers exhibit substantial residual resistance factors (permeability reduction values). If these values were valid, they could significantly reduce the polymer concentration and volume needed for a flood. Unfortunately, these high residual resistance factors were often an experimental artifact that resulted (1) from not injecting sufficient water to displace the polymer during core floods and/or (2) from using short cores with no internal pressure taps. The reader should be suspicious of residual resistance factors above two unless the rock permeability is less than 200 md or the polymer molecular weight is extraordinarily high. A conservative approach to polymer flood design would assume that residual resistance factor is one (Seright 2010).

Another invalid concept is that a small bank of viscous polymer solution can be pushed intact through a reservoir by a water post-flush. Some have advocated that as the viscous polymer solution propagates intact through a high-permeability layer, the water post-flush will be forced into adjacent low-permeability layers—where it will displace oil. This concept is not correct. In cases where fluids can crossflow between layers, a water post-flush will preferentially finger through the polymer bank in the most-permeable layer (Cyr *et al*. 1988, Sorbie and Seright 1992, Seright *et al*. 2012). This fact can be appreciated by viewing the videos mentioned in the discussion between Figs. 1 and 2. These videos clearly show that water will break through the polymer bank in the high-permeability layer before water has a chance to much displace fluid from less-permeable layers. For cases where fluids cannot crossflow between layers, Seright (1991b) demonstrated (both theoretically and experimentally) that a water post-flush breaks through the polymer bank in all open layers at about the same time. Consequently, sweep efficiency cannot be expected to be maintained or improved during water injection following a polymer bank.

Polymer retention plays a critical role in deciding the size of the polymer bank. The viscous polymer solution must penetrate deep into the reservoir to displace the oil. If polymer retention is less than 30 μg/g and polymer concentration is moderate to high ($>$1000 ppm), polymer retention does not greatly delay movement of the polymer bank. However, if polymer retention is greater than 100 μg and especially if polymer concentrations are low, multiple pore volumes of polymer solution may be needed to flood the reservoir (Manichand and Seright 2014).

Economic Considerations

If the above technical considerations are incorporated properly, the decision when to stop polymer flooding is largely an economic issue. Most field case histories of polymer flooding report overall economic aspects of their project. In this paper, our concern with economics is focused on whether it limits either the polymer concentration used or the volume of the polymer bank. When the cost of injecting the polymer solution exceeds the value of the produced oil, polymer injection is stopped. Of course, this time will depend greatly on oil price, polymer cost, and many individual factors associated with a given field. So, a ″one-size-fits-all″ formula cannot be expected for the optimum bank size.

Many authors pointed out that well spacing can greatly affect the timing and economics of a polymer flood. The increased rate of recovery and improved sweep efficiency gained from smaller well spacing must be balanced against the cost of infill wells (Wang *et al.* 2008b, Wang *et al.* 2009, Wassmuth 2007). At Daqing, Wang *et al*. (2008b) reported optimum polymer injection rates of 0.14 to 0.16 PV/year for 250-m spacing and 0.16 to 0.20 PV/year for 150-175-m well spacing.

The few papers that focus on when to stop polymer injection are associated with the Daqing polymer flood. Wang *et al*. (2008b, 2009) may provide the most extensive discussion, reporting that polymer injection was switched to water cut when the water cut reached 92-94%. For many of the newer polymer floods, operators are just now faced with the decision on when to stop polymer injection—especially in view of low oil prices.

If the achievable injection rate is governed dominantly by polymer viscosity, the total fluid production rate will be slowed by polymer injection (given a fixed pressure drop across the system). An economic optimum will occur if the increased fractional flow of oil from polymer flooding must be balanced against a reduced total fluid production rate (Seright 2010). However, as mentioned earlier, fracture extension can mitigate or eliminate injectivity losses under the proper circumstances. If fractures are not taken into consideration during simulations of polymer flooding, a substantial pressure drop is typically predicted in the injection grid block—which predicts a false (low) ″economic optimum″ polymer concentration (Moe Soe Let *et al*. 2012). Care must be exercised during simulations to avoid this effect if polymer solutions are injected above the formation parting pressure.

Should Polymer Banks Be Graded at the End of Polymer Injection?

During water injection after polymer in the experiments with 11.2:1 permeability contrast (i.e., those shown in Fig. 2), injected water formed viscous fingers that broke through in the high-permeability layer after advancing the polymer front by 70% when the polymer-bank viscosity was 8 cp, by 40% when the polymer bank viscosity was 23 cp, and by 25% when the polymer bank viscosity was 75 cp.

In contrast to the laboratory experiments, water breakthrough appears more rapid in field applications. At Daqing, after injecting ~1 PV of 40-cp polymer solution (well spacing: 250 m), water cuts typically stabilized at about 90% (Han 2015). When injection was switched from polymer to water at Daqing, water breakthrough was first noted after ~0.02 PV (by the first increase in water cut). During continued water injection, the water cut rose and stabilized at 96%-98% after 0.23 PV of water (Han 2015).

At the Mangala polymer flood pilot in India, the main polymer-bank concentration was 2000-2500-ppm HPAM. After the polymer concentration was reduced to 1700-1800-ppm HPAM, injection profiles gradually deteriorated (Prasad *et al*. 2014).

To mitigate viscous fingering near the end of a polymer flood, Claridge (1978) and Stoneberger and Claridge (1988) developed methods for grading polymer viscosities. They recognized that their grading method was most appropriate for application in homogeneous reservoirs, and that viscous fingering is most severe when heterogeneity exists. Cry *et al*. 1988 argued that grading schemes would not be of practical benefit for polymer flooding and that once polymer concentrations were reduced or polymer injection was stopped, the polymer flood would effectively be finished. Several of the field polymer floods used (or plan) graded polymer banks (see Table 1). Although graded banks are commonly used or planned in field applications, more work is needed to demonstrate their utility and to identify the most appropriate design procedure.

Strategies When Oil Prices Fall

In view of the precipitous drop in oil prices from 2014 to 2015, operators of existing polymer floods wonder how they should proceed. Should these projects be switched to water injection immediately? Should the polymer concentration be reduced or graded? Should the polymer concentration stay the same but reduce the injection rate? Of course, the answer will depend partly on whether the flood is profitable at the current oil price.

Consider the Daqing case mentioned above, where injection of 1000-1300-ppm HPAM resulted in a stabilized water cut of ~90%, while subsequent water injection resulted in a stabilized water cut of ~97%. Assuming \$1.50/lb for HPAM cost, the chemical cost of polymer injection was \$0.52-\$0.68/bbl. Assuming \$100/bbl for oil price, the value of the produced fluid was \$10/bbl when the water cut was 90% (i.e., during polymer injection) versus \$3/bbl when the water cut was 97%. Assuming \$40/bbl for oil price, the value of the produced fluid was \$4/bbl when the water cut was 90% (i.e., during polymer injection) versus \$1.20/bbl when the water cut was 97%. With either oil price, continued polymer injection is preferred over water injection (assuming other operational costs associated with polymer injection are not prohibitive).

If the voidage replacement ratio is one, reducing the injection rate is not likely to improve the economics for the scenarios mentioned above. However, the voidage replacement ratio for several recent polymer floods was noticeably greater that one; values of two have been observed. In searching for the reason why these projects had high voidage replacement ratios, dilation of the reservoir was suggested during polymer injection. Compaction and dilation are uncommon phenomenon in the experience of most reservoir engineers. However, recent polymer floods in unconsolidated reservoirs appear to have an unusually compressible nature. For example, for the Tambaredjo field in Suriname, 20% OOIP was produced during primary production, dominantly via compaction (Moe Soe Let *et al*. 2012). During polymer injection after primary production, compaction is reversed—i.e., the reservoir is actually dilated, average porosity increases, and the voidage replacement ratio can be significantly greater than one. During times of low oil prices, there may be value in reducing or stopping injection and allowing compaction again become the dominant drive mechanism.

As pointed out earlier (Seright 2010), polymer flooding is probably the most forgiving enhanced oil recovery process. So many actions that may be taken during times of low oil price do not have a permanent detrimental effect that cannot be reversed when the economic outlook improves.

Conclusions

1. A base-case reservoir-engineering method is present for deciding the polymer solution viscosity that should be injected during a polymer flood. This method focuses on waterflood mobility ratios and the permeability contrast in the reservoir.
2. Unique relative permeability curves and low endpoint k_{rw} values have been used to justify injecting low viscosity polymer solutions to displace viscous oils (>1000 cp). However, incorrect

assumption of overly optimistic relative permeability and the consequent selection of low injected polymer solution viscosity can lead to early polymer breakthrough and its associated inconveniences. In some cases, insufficient waterflooding (e.g., 5 PV) was performed to determine k_{rwo}. With viscous oils, more than 100 PV of water flush is needed to approach the appropriate k_{rwo}. A low mobility ratio at the shock front does not guarantee an efficient displacement of a viscous oil. Viscous fingering may make displacements much less efficient than expectations based on shock-front mobility ratios.

3. In homogeneous reservoirs, the ratio of produced oil value to injected fluid cost is fairly insensitive to injected polymer viscosity (up to the viscosity predicted by the base-case method above), especially at low oil prices. However, reservoir heterogeneity and economics of scale associated with the polymer dissolution equipment favor high polymer viscosities over low polymer viscosities, if injectivity is not limiting.
4. Many residual resistance factors that were reported in the literature (for permeability above 200 md) are probably too high because not enough brine was injected to displace the mobile polymer or because non-propagating high-molecular-weight polymer species caused artificially high resistance to flow during short core experiments. More than 100 PV of water flush may be needed to achieve an appropriate residual resistance factor. Accepting high experimental residual resistance factors without caution may lead to not injecting a large enough polymer bank or a high enough polymer concentration in the polymer bank. To be conservative during the design of a polymer flood, residual resistance factors should be assumed to be unity, unless reservoir permeability is low (<200 md).
5. Injection above the formation parting pressure and fracture extension are crucial to achieving acceptable injectivity for many polymer floods—especially those using vertical injectors. Under the proper circumstances, this process can increase fluid injectivity, oil productivity, and reservoir sweep efficiency, and also reduce the risk of mechanical degradation for polyacrylamide solutions. The key is to understand the degree of fracture extension for a given set of injection conditions so that fractures do not extend out of the target zone or cause severe channeling.
6. Many field cases exist (Daqing, Suriname, Canadian floods) with no evidence that fractures caused severe polymer channeling or breaching the reservoir seals, in spite of injection significantly above the formation parting pressure.
7. Although at least one case exists (Daqing) where injection of very viscous polymer solutions (i.e., more viscous than the base-case design above) reduced S_{or} below that for waterflooding, our understanding of when and how this occurs is in its infancy. At this point, use of polymers to reduce S_{or} must be handled experimentally on a cases-by-case basis.
8. When the cost of injecting the polymer solution exceeds the value of the produced oil, polymer injection is stopped. This time will depend greatly on oil price, polymer cost, and many individual factors associated with a given field. So, a ″one-size-fits-all″ formula cannot be expected for the optimum bank size. However, experience and technical considerations favor using the largest practical polymer bank. In particular, channeling/viscous fingering will be very severe when water injection occurs after polymer injection.
9. Although graded banks are commonly used or planned in field applications, more work is needed to demonstrate their utility and to identify the most appropriate design procedure.

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Nomenclature

C_{poly} = polymer concentration, ppm [g/cm^3]
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 Layer 1, ft [m]
h_2 = height of Layer 2, ft [m]
$IAPV$ = inaccessible pore volume
k = permeability, darcys [m^2]
k_{cont} = permeability contrast (high-permeability/low-permeability)
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, darcys [m^2]
k_2 = permeability of Layer 2, darcys [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]
M = mobility ratio (water mobility/oil mobility)
M_w = molecular weight, daltons [g/mol]
n = power-law exponent
no = oil saturation exponent
nw = water saturation exponent
PV = pore volumes of fluid injected
PV_{ret} = pore volume delay per pore volume injected
ΔPV = pore volumes difference
Δp = pressure difference, psi [Pa]
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 Layer 1, ft/d [m/d]
v_2 = front velocity in Layer 2, ft/d [m/d]
μ = viscosity, cp [mPa-s]
μ_o = oil viscosity, cp [mPa-s]
μ_{poly} = polymer solution viscosity, cp [mPa-s]
ϕ = porosity
ϕ_1 = porosity in Layer 1
ϕ_2 = porosity in Layer 2

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SI Metric Conversion Factors

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