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## **New Insights into Polymer Rheology in Porous Media**

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### **Abstract**

This paper clarifies the rheology of xanthan and HPAM solutions in porous media, especially at low velocities. Previous literature reported resistance factors (effective viscosities in porous media) and an apparent shear thinning at low fluxes that were noticeably greater than expected from viscosity measurements. The polymer component that causes the latter behavior is shown to propagate quite slowly and generally will not penetrate deep in a formation. Particularly for HPAM solutions, this behavior can be reduced or eliminated for solutions that experience mechanical degradation and/or flow through a few feet of porous rock. Under practical conditions where HPAM is used for enhanced oil recovery, the degree of shear thinning is slight or non-existent, especially compared to the level of shear thickening that occurs at high fluxes.

### **Introduction**

Polymer rheology in porous media affects both injectivity and sweep efficiency during a chemical flooding enhanced oil recovery (EOR) process. At moderate to high fluid velocities in porous media, xanthan solutions show shear thinning that closely follows xanthan's viscosity behavior (Chauveteau 1982, Cannella *et al.* 1988, Hejri *et al.* 1991, Seright *et al.* 2009a). However, at low velocities in short cores, the literature (Cannella *et al.* 1988, Hejri *et al.* 1991, Seright *et al.* 2009a) reported that xanthan continues to show shear thinning, whereas viscosity data predicts Newtonian behavior (first Newtonian region of the Carreau model). Because most oil is displaced at low velocities, resolution of this discrepancy is needed for accurate representation of xanthan resistance factors when simulating chemical flooding processes.

A related phenomenon occurs for partially hydrolyzed polyacrylamide (HPAM) solutions. In porous media, HPAM solutions have been well-documented to show shear thickening (also called dilatant, pseudodilatant, and viscoelastic behavior)—the resistance factor increases with increased flux for moderate to high fluid velocities (Pye 1964, Smith 1970, Jennings *et al.* 1971, Hirasaki and Pope 1974, Seright 1983, Masuda *et al.* 1992, Seright *et al.* 2009a). At low velocities in porous media, some authors reported a mild shear-thinning behavior (Heemskerk *et al.* 1984, Masuda *et al.* 1992, Delshad *et al.* 2008), while others report Newtonian or near-Newtonian behavior (Seright *et al.* 2009a). As with xanthan, expectations based on viscosity measurements imply that Newtonian behavior should be observed at low velocities in porous media. Again, a need exists to resolve this discrepancy so that proper resistance factors can be used as input during estimation of oil recovery from EOR projects.

In this paper, we demonstrate how xanthan and HPAM rheology in porous media correlates with permeability and porosity. We confirm the existence of unexpectedly high resistance factors at low fluxes in short cores. We examine whether the polymer component that causes this behavior can propagate penetrate deep in a formation under practical conditions. Finally, we consider circumstances when shear thinning can be expected to materialize for HPAM solutions deep within a formation.

### **Xanthan**

**Resistance Factors versus Flux.** For our first studies with xanthan, we used two Berea sandstone cores (55-md and 269-md permeability) and one porous polyethylene core (5,120-md permeability). The 55-md Berea sandstone core was 14.35 cm long, with a square cross-section of 11.34 cm<sup>2</sup>. Porosity was 17% and the pore volume was 27.7 cm<sup>3</sup>. Two internal pressure taps divided the core into three sections with lengths of 2.2 cm, 10.15 cm, and 2 cm, respectively. The 269-md Berea sandstone core was 12.78 cm long, also with a square cross-section of 11.34 cm<sup>2</sup>. Porosity was 21.2% and the pore volume was 30.8 cm<sup>3</sup>. Two internal pressure taps divided the core into three sections with lengths of 2.39 cm, 8.75 cm, and 1.64 cm,

respectively. The polyethylene core was 15.27 cm long, with a square cross-section of 11.64 cm<sup>2</sup>. The pore volume was 62.8 cm<sup>3</sup>. Two internal pressure taps divided the core into three sections with lengths of 2.54 cm, 10.3 cm, and 2.43 cm, respectively. Our previous research (Seright *et al.* 2006) demonstrated that the pore structure of porous polyethylene was quite similar to that for Berea sandstone, although the porosity was considerably higher (35% versus 17% and 21.2% for the two Berea cores). The cores were initially saturated with 2.52% TDS (total dissolved solids) brine (2.3% NaCl+0.22% NaHCO<sub>3</sub>). This brine was filtered through 0.45 μm filters and was used to prepare all polymer solutions. All experiments were performed at 25°C.

After saturation with brine, at least 20 pore volumes (PV) of xanthan solution were injected to insure that polymer retention was satisfied in the cores. The xanthan gum, K9D236™, Lot #6441F470C, was supplied as a white powder by CP Kelco. This polymer had a molecular weight between 2 and 2.5 million daltons and a pyruvate content of 4.5%. The injected polymer solution contained 0.06% (600 parts per million, ppm) xanthan in brine. The low-shear-rate viscosity (i.e., the first Newtonian region) for this solution was 8 cp. After saturating the cores with this polymer solution, injection rates were varied over a wide range (from 0.0174 to 1,111 ft/d), and resistance factors were measured in the three sections of each core. Fig. 1 plots resistance factors for the middle sections of the three cores.

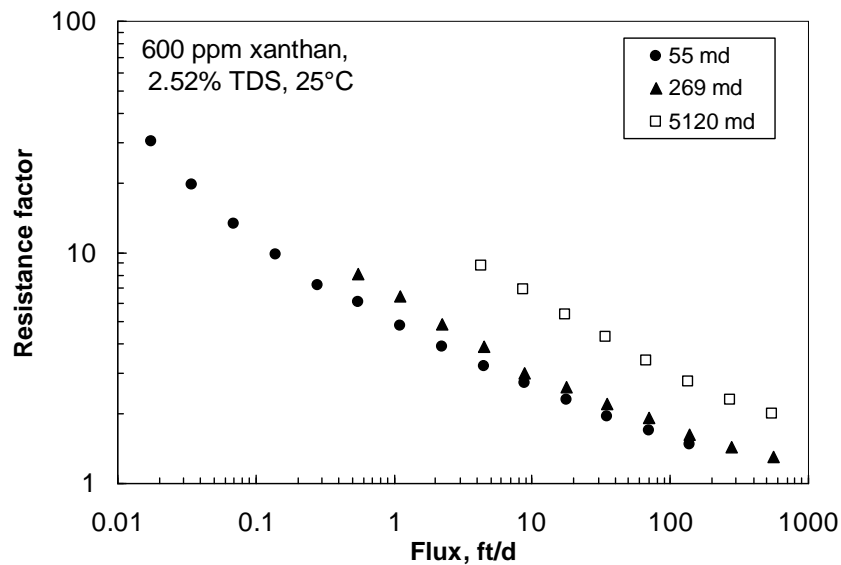


Fig. 1—Resistance factor versus flux for 600-ppm xanthan.

**Permeability Dependence of Rheology.** Resistance factors can depend on permeability simply because the effective shear rate varies with pore size. A given rheological curve is expected to shift to higher velocities in proportion to the square root of the permeability ratio (Chauveteau 1982, Seright 1991). For our three cores, we found that resistance factor correlated quite well (see Fig. 2) using the parameter  $u(1-\phi)/(\phi k)^{0.5}$ , where  $u$  is flux (in ft/d),  $\phi$  is porosity, and  $k$  is permeability (in md). With an original basis in a capillary bundle model of porous media, many previous researchers used the correlating parameter,  $u/(\phi k)^{0.5}$ , or a modification thereof (Hirasaki and Pope 1974, Chauveteau 1982, Durst *et al.* 1982, Duda *et al.* 1983, Heemskerk *et al.* 1984, Cannella *et al.* 1988, Wreath *et al.* 1990, Hejri *et al.* 1991, Seright 1991).

Consistent with previous literature (Cannella *et al.* 1988, Hejri *et al.* 1991), Fig. 2 confirms that xanthan solutions show shear-thinning or pseudoplastic behavior in porous media. The solid curve in Fig. 2 shows that the viscosity data parallels the resistance factor in the shear-thinning region. To make this match, shear rates (in s<sup>-1</sup>, associated with the viscosity data) were divided by 310 when plotted on the  $x$ -axis. (This value of 310 was strictly an empirical factor that was needed to make the shear-thinning portions of the curves match.)

**Unexpectedly High Resistance Factors at Low Fluxes.** For the xanthan solution, the viscosity at low shear rates exhibited a plateau value of 8 (i.e., 8 cp or flow resistance 8 times greater than water, solid curve in Fig. 2). Consequently, based on viscosity (versus shear rate) data, we expected to see Newtonian (flow-rate-independent) behavior at low flux values. Instead, in 55-md Berea sandstone, resistance factors at low flux reached as high as 30 (solid circles in Fig. 2). This behavior was also reported for xanthan solutions by Cannella *et al.* (1988) and Hejri *et al.* (1991). In 269-md Berea and 5,120-md porous polyethylene, we did not achieve sufficiently low velocities to observe this phenomenon.

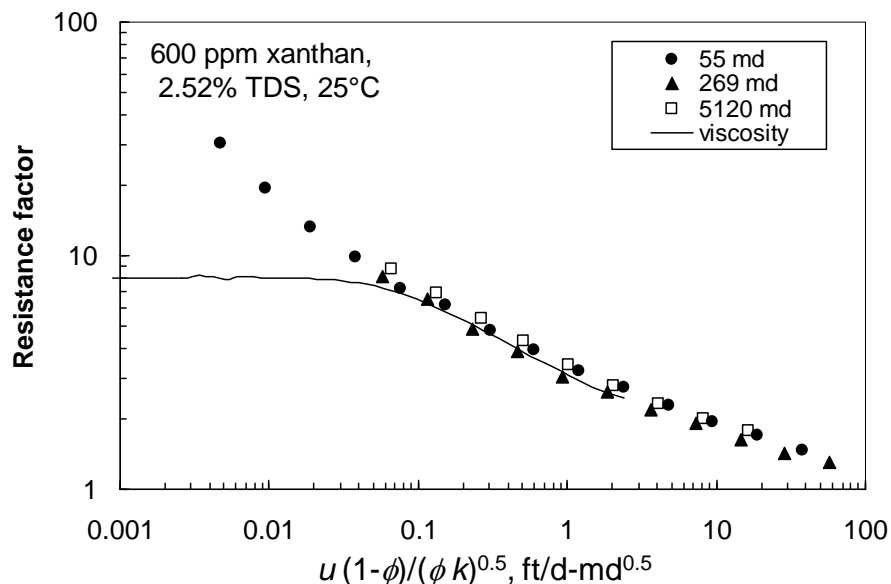


Fig. 2—Correlated resistance factors for 600-ppm xanthan.

We were concerned that this apparent shear-thinning behavior in our short cores might be an experimental artifact (associated with microgels or very high  $M_w$  polymer species) that could not be expected to propagate deep into a real reservoir. To test this idea, we performed an experiment in a 57-md Berea sandstone core that was 122 cm long, with four equally spaced internal pressure taps—which created five 24.4-cm sections within the core. The core porosity was 17.3%, and the core cross-section was 15.24 cm<sup>2</sup>. The permeabilities of the five core sections were 53 md, 64 md, 65 md, 74 md, and 41 md, respectively—giving a composite permeability of 57 md. The core was saturated with filtered 2.52% TDS brine (2.3% NaCl + 0.22% NaHCO<sub>3</sub>), and our polymer solution contained 600-ppm CP Kelco K9D236 xanthan in this same brine.

We injected 2.5 PV of xanthan solution at 5.17 ft/d flux. (One PV was 321 cm<sup>3</sup>.) At that time, we varied the polymer injection rate over a wide range (0.005 to 5 ft/d). The resistance factor was measured at each rate in each of the five core sections. Values for the second through fifth core sections are plotted in Fig. 3: open triangles for the second core section (24–48 cm from the core inlet); open diamonds for the third core section (48–73 cm); open squares for the fourth core section (73–98 cm); open circles for the fifth core section (98–122 cm). (The first core section of this long core was treated as a filter.) Two other data sets are included for comparison in Fig. 3. First, the solid circles plot resistance factors from the center 10.15-cm section of the short (14.35-cm) 55-md Berea core in Figs. 1 and 2 (with the data obtained after injecting 20 PV of xanthan solution). Second, the solid curve plots viscosity data (versus adjusted shear rate) for the xanthan solution that was injected into the 122-cm core.

For flux values above 0.1 ft/d, the various data sets in Fig. 3 converged. However, they diverged as flux decreased below 0.1 ft/d. At the lowest fluxes, the resistance factors approached the zero-shear viscosity value as the distance progressed into the core. This result supports our original suspicion that the unexpectedly high low-flux xanthan resistance factors may not practically propagate deep into a porous medium (i.e., a reservoir).

**Calculations Quantifying Propagation of the High-Flow-Resistance Species.** Calculations were performed to appreciate and quantify the degree to which the high low-flux xanthan resistance factors will propagate into 40-80-md sandstone. Injecting 2.5 PV of polymer solution into the 122-cm core translates to injecting 3.1 PV through to the fourth pressure tap, 4.2 PV through to the third tap, 6.2 PV through to the second tap, and 12.5 PV through to the first pressure tap. If a xanthan bank was injected into a horizontal well to reach 500 ft into the formation, the behavior seen in Core Section 5 of Fig. 3 (open circles, essentially the viscosity behavior) would occur out beyond 160 ft from the well [i.e., 500 ft/(2.5 PV) × (80% of the core length, associated with the beginning of the fifth core section)]. The behavior seen in Core Section 4 (open squares of Fig. 3) would occur from 120 to 160 ft from the well. The behavior seen in Core Section 3 (open diamonds of Fig. 3) would occur from 80 to 120 ft; and the behavior seen in Core Section 2 (open triangles of Fig. 3) would occur from 40 to 80 ft. Thus, depending on the level of the effect, the rate of propagation of the polymer species that causes the effect ranges from 1/6 (i.e., 80 ft/500 ft) to 1/3 (i.e., 160 ft/500 ft) the rate of propagation for the remainder of the polymer.

For vertical wells, where flow is radial, the positions farthest from the wellbore and away from the most direct well-to-well streamlines would see the lowest flux values, but would also experience the lowest polymer throughput values. Consequently, the high xanthan resistance factors associated with the low-flux solid-circle data points in Figs. 2 and 3 are unlikely to materialize in these remote low-flux locations.

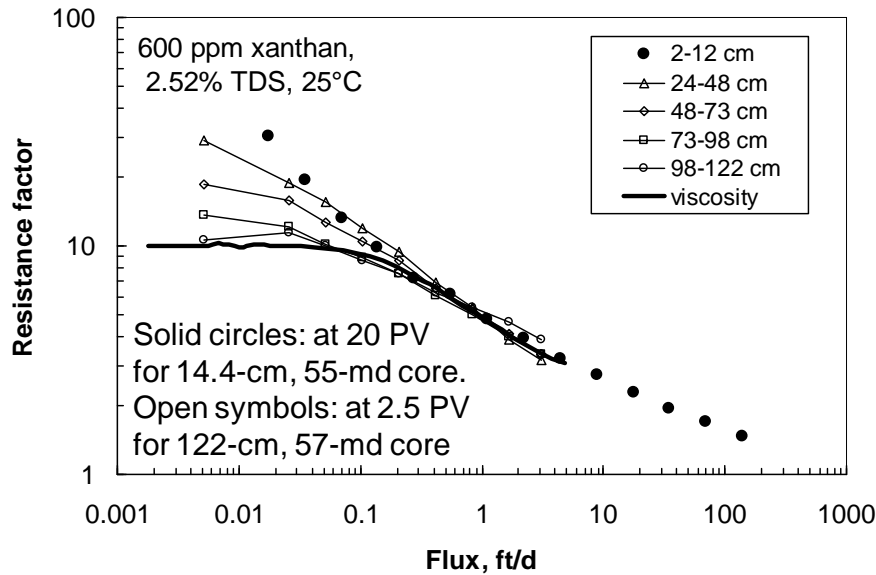


Fig. 3—Are high low-flux resistance factors able to propagate?

### HPAM

After the xanthan experiments in the three cores mentioned in Figs. 1 and 2, we injected at least 19 PV of 0.25% (2,500-ppm) SNF Flopaam 3230S HPAM (partially hydrolyzed polyacrylamide, Lot UE 3770) in 2.52% TDS brine. (The manufacturer estimated the molecular weight of this polymer at 6-8 million daltons, with a degree of hydrolysis of 30%.) After saturation with this polymer, flux was varied over a wide range (0.035 to 135 ft/d) while measuring resistance factors. The results, expressed as resistance factor versus the parameter  $u(1-\phi)/(\phi k)^{0.5}$ , are shown by the open symbols in Fig. 4.

**Behavior at High Rates.** Consistent with previous literature (Jennings *et al.* 1971, Durst *et al.* 1982, Southwick and Manke 1988, Seright *et al.* 2009a), Fig. 4 confirms that HPAM resistance factors increase with increased flux at moderate to high flux values. This behavior was attributed to the viscoelastic character of HPAM and the elongational flow field in porous rock. In the past, this phenomenon has been called “shear thickening”, “dilatant”, “pseudodilatant”, and “viscoelastic” behavior. For consistency, we will use the term “shear thickening”, despite objections that might be raised by purists. Consistent with earlier work (Durst *et al.* 1982), the onset of the shear-thickening behavior correlated well with the parameter,  $u(1-\phi)/(\phi k)^{0.5}$ . The solid curve in Fig. 4 shows viscosity data (again with shear rate divided by 310 plotted on the  $x$ -axis). Interestingly, the onset of shear-thickening resistance factors in Fig. 4 correlated closely with the transition from Newtonian to shear-thinning viscosity behavior. This point will be discussed in detail later.

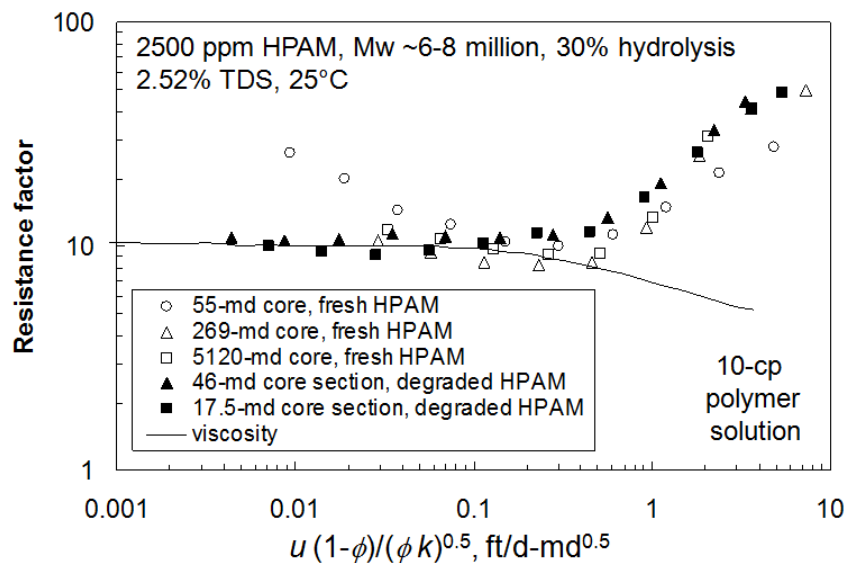


Fig. 4—Resistance factors for 2500-ppm HPAM.

**HPAM Shear-Thickening Behavior and Mechanical Degradation.** HPAM solutions are susceptible to mechanical degradation (Maerker 1975, Maerker 1976, Seright 1983). The degree of mechanical degradation experienced by the polymer correlates with the applied pressure gradient (Seright 1983). This fact explains the differences in resistance factors at the highest velocities in Fig. 4. As the correlating parameter ( $x$ -axis) increases above 0.4, resistance factor increased most steeply for the 5,120-md data (open squares in Fig. 4) and least steeply for the 55-md data (open circles). For a given value of the correlating parameter in this region, pressure gradient varied inversely with the square root of permeability. Consequently for a given value of the correlating parameter, as permeability decreased, pressure gradient increased, the level of polymer mechanical degradation increased, and the observed resistance factor decreased.

**Behavior at Low Rates.** For HPAM solutions, a viscosity plateau occurred at low shear rates (solid curve in Fig. 4), just as with xanthan solutions. Thus, we also expected resistance factors to approach a fixed value at low flux values. This expectation was met reasonably well by the low-flux HPAM resistance factors in 269-md Berea and 5,120-md polyethylene. (Although, one might argue in favor of a very mild shear-thinning behavior in porous media.) However, in 55-md Berea, a significant shear thinning behavior was noted at low flux (open circles in Fig. 4). We suspected that this behavior was caused by ultra-high molecular weight polymers or “microgels” (Chauveteau and Kohler 1984). These high  $M_w$  species may become mechanically entrapped (especially in less-permeable rock) and consequently reduce permeability and make the resistance factor appear significantly greater than the values expected from viscosity measurements. Important questions include: Will this behavior occur deep within a reservoir or is it simply a laboratory artifact associated with using relatively short cores? Can these high molecular weight species be expected to propagate very far into the porous rock of a reservoir? Will they be mechanically degraded into smaller species (as suggested by Seright *et al.* 1981)? Will they be retained by the rock fairly close to the injection rock face (as suggested by Chauveteau and Kohler 1984)?

**HPAM Shear-Thinning Behavior and Mechanical Degradation.** For the experiments reported to this point, the solutions were freshly prepared. In field applications, polymer solutions are likely to experience some level of mechanical degradation before penetrating deep into the reservoir. Most probably, the greatest level of mechanical degradation will occur as the polymer solutions first leave the wellbore and enter porous rock (Maerker 1975, Maerker 1976, Seright 1983, Seright 2009a). That is where the velocities are highest in the reservoir rock. Our previous experience suggested that the high molecular weight species are responsible for HPAM causing permeability reductions and an unexpected shear thinning at low velocities in porous rock. These species are especially susceptible to mechanical degradation (Seright *et al.* 1981). To examine this issue further, we performed another set of experiments where HPAM solutions were first forced through a core at a high pressure gradient. Specifically, we forced the polymer solutions through a 13.3-cm long, 32-md Berea sandstone core using a pressure difference of 1,000 psi (2,292 psi/ft). This level of pressure gradient might be experienced by a polymer solution as it leaves a vertical wellbore to enter the formation rock.

The effluent from this core was re-injected into a second Berea core using a wide range of flux values to determine resistance versus flux for the mechanically-degraded polymer solutions. This process imitates what happens to a polymer solution as it flows radially away from a wellbore. The second core (13.9 cm total length, 38-md composite permeability) had three sections with pressure taps located 2.2 cm from the inlet sand face and 1.9 cm from the outlet sand face. The second core section was 9.8 cm long and had a permeability of 46 md. The third core section (1.9 cm long) had a permeability of 17.5 md. (The first 2.2-cm core section, with a permeability of 48 md, was treated as a filter for the core.)

The solid symbols in Fig. 4 plot resistance factor versus flux for the second (46-md) core section (solid triangles) and for the third (17.5-md) core section (solid squares) for the degraded SNF 3230S HPAM. As mentioned earlier, the open symbols in Fig. 4 plot resistance factors for undegraded (fresh) polymer solutions from 55-md, 269-md, and 5,120-md cores. The onset of shear-thickening behavior occurred at about the same  $x$ -axis value for all five cases. At low flux values, resistance factors for four of the five curves leveled out (i.e., approached Newtonian behavior) at a value consistent with the viscosity of the SNF 3230S polymer solution (10 cp). For the exception, fresh polymer injected into a 55-md core (open circles), resistance factors increased from 10 to 26 as flux decreased from 1.1 to 0.035 ft/d (i.e. the correlating parameter on the  $x$ -axis decreased from 0.3 to 0.009 ft/d-md<sup>0.5</sup>). When the experiment was repeated with mechanically degraded SNF 3230S polymer in the 46-md and 17.5-md Berea core segments (solid symbols in Fig. 4), Newtonian behavior was seen at low flux values. This result confirms that mechanically degraded polymer did not contain the components that caused the apparent shear thinning in the 55-md core.

Viscosity versus shear rate was measured for the polymer solution both before and after being forced through the first core. No significant viscosity difference was seen at any shear rate. These observations are consistent with earlier work (Seright *et al.* 1981) that revealed that the high molecular weight polymer species that cause high permeability reductions and high screen factors can be removed/degraded without causing large differences in viscosity behavior.

**HPAM Behavior after Flow through Rock at Low Flux.** The previous experiment revealed that the species causing shear thinning in porous rock (associated with the open circles at low flux in Fig. 4) were removed or degraded when forced through rock at a high pressure gradient (2,292 psi/ft). We wondered whether it would also be removed by flow through rock at much lower pressure gradients. To address this question, a long Berea sandstone core was constructed, much like that used in Fig. 3. This core was 122 cm (4 ft) long and 15.24 cm<sup>2</sup> in cross-section, had a pore volume of 321 cm<sup>3</sup>, a porosity of

17.3%, and an average permeability of 47 md. We injected 9.2 PV of HPAM solution (2,500-ppm SNF Flopaam 3230S in 2.52% TDS brine) at a fixed flux of 1.6 ft/d. The effluent from the last part of this injection was then injected into a shorter Berea sandstone core, where we determined resistance factor versus flux. The short core 13.28 cm (0.44 ft) long and 11.34 cm<sup>2</sup> in cross-section, and had a pore volume of 26.3 cm<sup>3</sup>. This core had two internal pressure taps—one located 2.12 cm from the inlet core face and the other at 1.88 cm from the outlet face. Consequently, the middle section of the core was 9.28 cm in length. The three sections of the core had permeabilities of 73 md, 94 md, and 81 md, respectively. Fig. 5 plots resistance factor versus flux for the three sections of this short core. In all core sections, near-Newtonian behavior was noted at low flow—i.e., the shear thinning observed at low flux for injection of fresh HPAM solution in a 55-md core (open circles of Fig. 4) was eliminated. We attribute this effect (i.e., the shear thinning at low flux, associated with the open circles of Fig. 4) to a high molecular weight polymer species that is readily destroyed by mechanical degradation or retained by filtration. We do not anticipate that this species will propagate deep into porous rock of a reservoir.

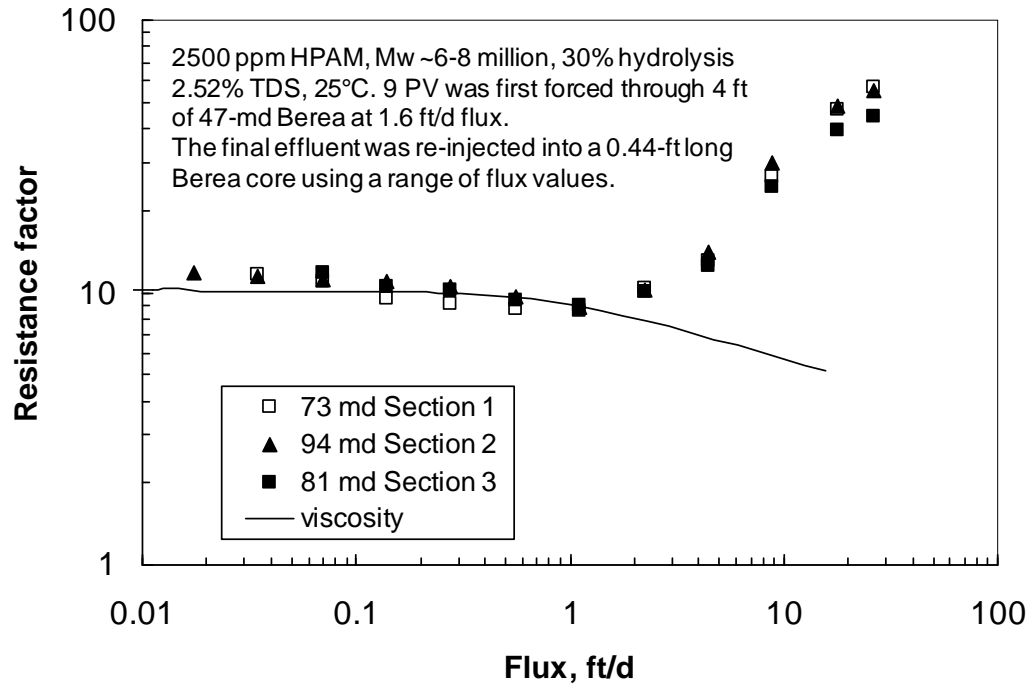


Fig. 5—HPAM resistance factors in Berea sandstone after flow through a 122-cm core at low flux.

### Permeability Dependence of Resistance Factors

As demonstrated in Figs. 2 and 4, polymer rheology in porous media correlated quite well using the parameter  $u(1-\phi)/(\phi k)^{0.5}$ . 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 (Jennings *et al.* 1971, Vela *et al.* 1976, Zaitoun and Kohler 1987, Zhang and Seright 2007, Wang *et al.* 2008, Wang *et al.* 2009). As permeability decreases below this critical value, resistance factors, residual resistance factors, and polymer retention can increase dramatically. As recommended by Wang *et al.* (2008, 2009), the molecular weight and size of the polymer should be chosen to be 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.

To investigate this effect further, we performed additional experiments using the 55-md, 269-md, and 5,120-md cores that were mentioned earlier. In particular, after the experiments with SNF 3230S HPAM (open symbols in Fig. 4), we performed nearly identical experiments using a sequence of HPAM polymers with increasing molecular weight. The first column in Table 1 lists the SNF Flopaam polymers in the sequence that they were tested. The second column lists the polymer molecular weights, as estimated by the manufacturer. All polymers had 30% degree of hydrolysis, except 3830S and 6030S, which had 40% degree of hydrolysis. Details of the experimental results can be found in Seright 2009b.

With one exception, the behavior of the various HPAM polymers were qualitatively similar to that for SNF 3230S. The exception was that a pore-plugging effect became increasingly evident as polymer  $M_w$  increased and as core permeability decreased. This result can be seen in Table 1, after some explanation of the data listings. For each case in Table 1, the lowest resistance factor that was observed in the second (longest) core section (i.e., taken from the wide range of resistance-factor-versus-flux measurements, such as those shown in Fig. 4) was divided by the polymer solution viscosity associated with the first Newtonian region (e.g., the low-shear-rate plateau shown by the thick solid line in Fig. 4). For the smallest polymer in

Table 1 (3230S), this ratio was nearly unity in all three cores. As the polymer molecular weight increased, this ratio increased, especially in the 55-md core. The ratio rose to 6.3 for the highest  $M_w$  polymer in the 55-md core. Interestingly, when the lowest  $M_w$  polymer was subsequently injected, the ratio fell to 1.3—indicating that the pore-plugging effect was largely reversible in these cores. In less-permeable porous rock (17.5 md and 46 md), we found the pore-plugging effect to be less reversible than observed in Table 1 (Seright 2009b). These observations are qualitatively consistent with results reported by previous researchers (Jennings *et al.* 1971, Vela *et al.* 1976, Wang 2008). The partial reversibility of the plugging effect could be attributed to hydrodynamic polymer retention (Maerker 1973, Chauveteau 1981).

**Table 1—Permeability reduction as a function of HPAM  $M_w$  and core permeability.**

Polymer	$M_w$ , million daltons	Ratio of minimum $F_r$ to low-shear-rate viscosity		
		55-md core	269-md core	5,120-md core
3230S (1 <sup>st</sup> )	6-8	1.0	0.9	1.0
3330S	8-19	1.4	1.3	1.1
3430S	10-12	1.2	1.2	1.2
3530S	15	1.7	1.9	1.6
3630S	18	2.6	2.1	1.4
3830S	18-20	4.5	1.7	1.8
6030S	20-22	6.3	2.3	1.5
3230S (last)	6-8	1.3	1.1	1.0

### Can HPAM Solutions Show Shear Thinning in Porous Media Deep within a Formation?

Along with others, Chauveteau (1981) noted that HPAM solutions showed shear-thickening behavior at moderate to high velocities in porous media. However, he speculated that at moderate to low flux values in capillary constrictions or in porous media, HPAM resistance factors might show shear-thinning behavior, and ultimately, show Newtonian behavior at the very lowest velocities. Consequently, he suggested that resistance factors should exhibit a minimum value at intermediate fluxes. Data published by Heemskerk *et al.* (1984), Masuda *et al.* (1992), and Delshad *et al.* (2008) could be viewed as indicating that HPAM in porous media exhibits a subtle shear thinning at low fluxes and a shallow minimum in resistance factor at intermediate fluxes. The open squares in Fig. 6 may support this view for freshly prepared 900-ppm HPAM (SNF Flopaam 3830S) in 2.52% TDS brine, when flowing through 5,120-md porous polyethylene. However, the degree of shear thinning that was reported/observed was slight, and the existence of the shallow minimum is debatable. An earlier publication (Seright *et al.* 2009a) proposed that the observed shear thinning for HPAM solutions at low flux values in porous media could be an experimental artifact due to (1) use of insufficiently accurate pressure transducers, (2) inadequate temperature control, and (3) a polymer molecular weight that is too high to propagate without forming an internal or external filter cake (i.e., if the polymer contains significant concentrations of “microgels” or high molecular weight species that are too large to flow efficiently through the pore structure). The latter point was demonstrated earlier in this paper. Introduction of air into the core can also induce apparent shear thinning. If these experimental artifacts are avoided, can shear thinning occur during flow of polymer solutions in cores?

**HPAM in Very Low Salinity Water.** The work reported to this point was performed in brines with moderate to high salinity (at least 0.3% TDS). Gogarty (1967) reported a definitive shear thinning in cores for 1,200- to 1,800-ppm HPAM in water with less than 700-ppm (0.07%) TDS. Thus, it appears that shear thinning could materialize for HPAM solutions in porous rock if the salinity is sufficiently low. To confirm this possibility, we prepared HPAM solutions in distilled water, and injected them at various rates into a 5,120-md porous polyethylene core. Fig. 6 shows the results using SNF Flopaam 3830S HPAM (with  $M_w$  of 18-20 million daltons and degree of hydrolysis of 40%). For 400-ppm HPAM in distilled water (solid diamonds in Fig. 6), shear-thinning behavior was noted for flux values between 0.06 and 4.3 ft/d. The slope was -0.56 for a plot of  $\ln(\text{resistance factor})$  versus  $\ln(\text{flux})$ . A similar slope was noted for 1000-ppm HPAM in distilled water for flux values between 0.135 and 4.3 ft/d (solid squares in Fig. 6). However, for higher flux values, the resistance factors leveled off and began a gradual increase. This latter behavior may be due to the viscoelastic nature of the polymer. Interestingly, the slope of plots of  $\ln(\text{viscosity})$  versus  $\ln(\text{shear rate})$  were -0.85 for 400-ppm HPAM and -0.94 for 1000-ppm HPAM. Thus, the very strong shear-thinning character of these solutions was moderated considerably during flow through porous media.

As mentioned earlier, the open squares in Fig. 6 show the behavior of 900-ppm HPAM in 2.52% TDS brine. Consistent with Fig. 4, this curve shows a strong shear-thickening behavior at moderate to high flux values and near Newtonian behavior at low flux values. (Although one could argue the existence of a shallow minimum between 1 and 7 ft/d.) Thus, two key points may be taken from Fig. 6, along with our other results. First, HPAM solutions can show a definitive shear-thinning behavior at low flux values in porous media if the solvent is distilled water (or a solvent with *very* low salinity). Second, for HPAM solutions in more practical brines (i.e., >0.3% TDS), Newtonian or near Newtonian behavior is expected at low flux values deep within a reservoir.

**Relation between the Onset of Shear Thinning in a Viscometer versus the Onset of Shear Thickening in Porous Media.** As shear rate is increased for a polymer solution in a viscometer, a shear rate is encountered that marks the transition

from Newtonian behavior to shear thinning. This transition shear rate is associated with the “longest relaxation time in the linear viscoelastic spectrum” (Graessley 1974). Some think of this point as the shear rate where polymer conformations experience their first departure from a random coil configuration. The onset of shear thickening by HPAM solutions in porous media is also associated with a change in polymer conformation—specifically where the polymers undergo a coil-stretch transition, resulting in highly extended polymer conformations and large extensional stresses (Durst *et al.* 1982, Southwick and Manke 1988). A comparison of the solid curve and the data points in Fig. 4 implies that these two transition points (i.e., the transition from Newtonian behavior to shear thinning in a viscometer and the onset of shear thickening in porous media) might coincide. To explore this idea, we performed experiments using various concentrations (25 ppm to 1,600 ppm) of SNF Flopaam 3830S in 2.52% TDS brine. For this polymer under these conditions, we determined  $C^*$  (the concentration at which polymer behavior transitions from dilute to semi-dilute behavior) to be 200 ppm.

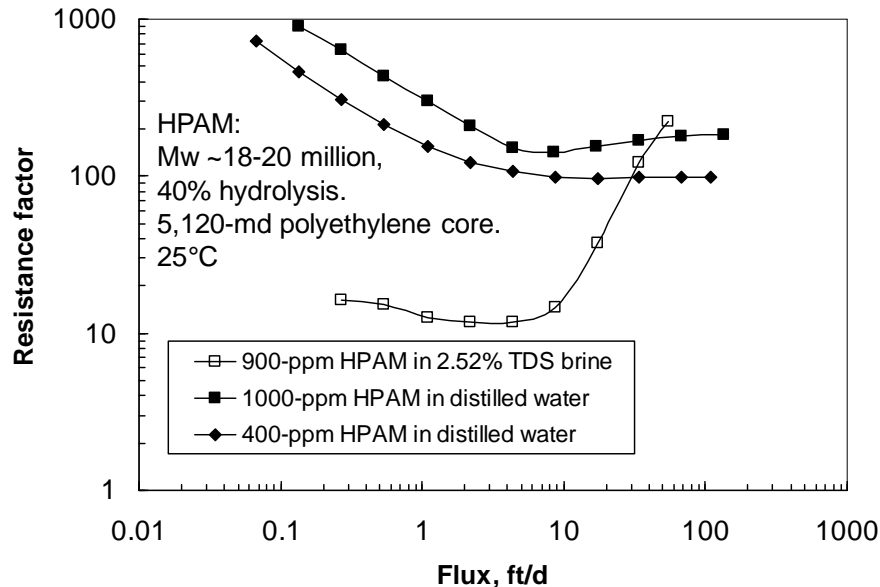


Fig. 6—Shear thinning by HPAM solutions in porous media.

Fig. 7 plots resistance factor versus flux during injection of many polymer solutions into a 5,120-md porous polyethylene core. For polymer concentrations even as low as 25 ppm (one-eighth the value of  $C^*$ ), shear thickening was evident. In contrast, viscosity versus shear rate showed Newtonian behavior, with a value very close to 1 cp. As described in the literature (Durst *et al.* 1982), the elongational flow field associated with porous media can accentuate viscoelastic behavior that is not apparent from a pure shear field. This observation provides our first reason to doubt that the transition from Newtonian behavior to shear-thinning in a viscometer correlates directly with the onset of shear thickening in porous media.

In Fig. 7, as polymer concentration increased from  $C^*$  (200 ppm) to 1,600 ppm, the onset of shear thickening decreased by a factor of two. For comparison, from viscosity-versus-shear-rate data, the shear rate at the transition from Newtonian behavior to shear thinning decreased by a factor of 10 (from 10 to 1  $s^{-1}$ ) over the same range of polymer concentrations. Since the variation in transition-from-Newtonian-to-shear-thinning shear rate (10, from the viscosity data) was much greater than the variation in onset of shear thickening (2, from resistance-factor data), the apparent correlation between the two transitions seen in Fig. 4 must be coincidental.

At low flux values in Fig. 7, the curves for the highest three polymer concentrations show slight shear thinning. The slopes of these curves were -0.236 for 1,600-ppm HPAM and -0.114 for 480-ppm HPAM. For comparison, the slopes of the shear-thinning portions of  $\ln(\text{viscosity})$ -versus- $\ln(\text{shear rate})$  curves were -0.218 and -0.127 for the two concentrations, respectively. The similarity of the shear-thinning slopes from viscosity and core data suggests that shear thinning might occur in porous media, even in saline brines. This information also indicates that the apparent correlation between the two transitions seen in Fig. 4 was coincidental.

**Significance of Observations.** For HPAM solutions with a sufficiently low salinity and/or sufficiently high polymer concentration, shear thinning can be observed in porous media at moderate to low fluxes. However, the degree of shear thinning was slight, especially compared to the level of shear thickening at higher fluxes.

The work in this paper indicates that under practical conditions for chemical flooding field applications, HPAM solutions show Newtonian or near-Newtonian behavior at low flux values, if ultra-high  $M_w$  polymer species are not present. Why is this point worth arguing? The reason is that cases exist where experimental artifacts and/or ultra-high- $M_w$  polymer species suggest that strong shear thinning occurs at low velocities in short corefloods. If this behavior is assumed to translate directly



to a reservoir scale, it leads to (1) an overly complex representation of polymer resistance factors, and (2) prediction of resistance factors that are too high deep in a formation. Also, most chemical flooding simulators have incorrectly assumed that the shear-thinning behavior observed by HPAM solutions in a viscometer will be directly applicable in porous rock—ignoring the importance of shear thickening at higher velocities. This incorrect assumption leads to (1) an overly optimistic prediction of polymer injectivity if wells are not fractured and (2) often, an incorrect prediction that fractures will not be open during polymer injection.

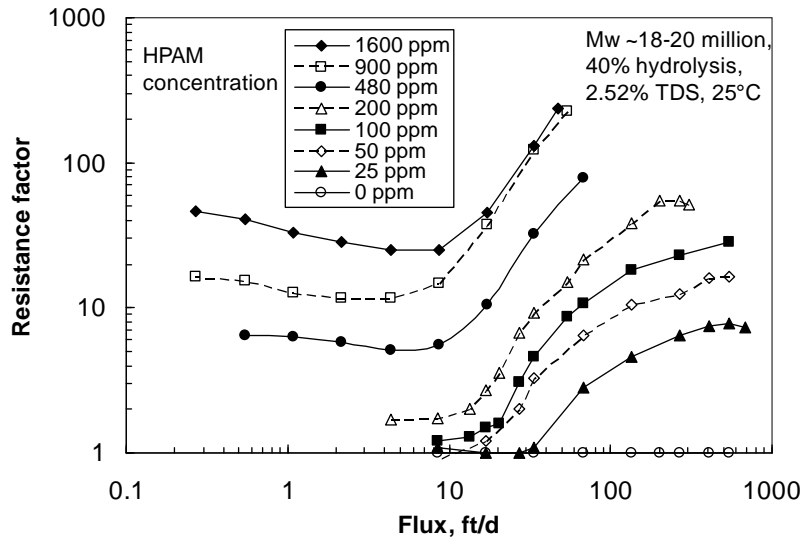


Fig. 7—Onset of shear thickening versus HPAM concentration in a 5,120-md core.

## Conclusions

1. At low velocities in short cores with sufficiently low permeability (e.g., 55 md), fresh xanthan solutions show shear thinning, whereas viscosity data predicts Newtonian behavior (first Newtonian region of the Carreau model). If the polymer component that causes this behavior is removed by flowing the polymer solutions through a few feet of rock, resistance-factor-versus-flux data closely follows expectations from viscosity-versus-shear-rate data. The polymer component that caused the unexpected shear thinning at low fluxes propagates through 40- to 80-md Berea at 1/6 to 1/3 the rate for the remainder of the xanthan solution.
2. In short cores with sufficiently low permeability (e.g., 55 md), shear thinning can be observed for fresh HPAM solutions at low fluxes that is much greater than the effect anticipated from viscosity-versus-shear-rate data. However, this shear thinning may be substantially reduced or eliminated by first either exposing the solution to high flux (i.e., characteristic of that seen near an unfractured injection well) or passing the solution through a few feet of rock at low flux. We attribute this effect to a high molecular weight polymer species that is readily destroyed by mechanical degradation or retained by filtration. We do not anticipate that this species will propagate deep into porous rock of a reservoir.
3. For HPAM solutions with a sufficiently low salinity and/or sufficiently high polymer concentration, shear thinning can be observed in porous media at moderate to low fluxes. However, under practical conditions where HPAM is used for EOR, the degree of shear thinning is slight or non-existent, especially compared to the level of shear thickening that occurs at high fluxes.

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## Nomenclature

- $C^*$  = critical polymer overlap concentration, ppm  
 $F_r$  = resistance factor (water mobility/polymer solution mobility)  
 $k$  = permeability, darcys [ $\mu\text{m}^2$ ]  
 $M_w$  = molecular weight, daltons  
 $PV$  = pore volumes of fluid injected  
 $u$  = flux, ft/d [m/d]  
 $\mu$  = viscosity, cp [mPa-s]

$\phi$  = porosity

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## SI Metric Conversion Factors

cp x 1.0*	E-03	= Pa·s
ft x 3.048*	E-01	= m

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in. x 2.54*	E+00	= cm
md x 9.869 233	E-04	= $\mu\text{m}^2$
psi x 6.894 757	E+00	= kPa