Are Field Polymer Enhanced Oil Recovery Projects Reaping the Benefits of Residual Oil Saturation Reduction Due to Polymer Viscoelasticity?

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Summary

For polymer solutions used in enhanced oil recovery (EOR), viscoelasticity is a rheological phenomenon that has a strong flux dependency and has been tied to significant reductions in residual oil saturation (S_{or}) during laboratory corefloods at high flux conditions. However, an unanswered question is whether the polymer's viscoelastic effects reduce S_{or} over a significant portion of a polymer-flooded reservoir.

In this paper, two methodologies are used to answer this question for polymer-flood projects across nine countries (Argentina, Austria, Canada, China, India, Oman, Russia, Suriname, and USA). In Method 1, the average Darcy velocity in each field is compared with the corresponding predicted velocity for the onset of shear thickening. Then, the effects of variables on Darcy velocity are examined, such as radial distance from the wellbore, well-spacing, horizontal well length, and thickness. In Method 2, the S_{or} reduction potential of the field polymer solutions used is evaluated by analyzing relevant coreflood experiments conducted in various laboratories. The observations from the laboratory results are considered in view of the fluid velocity, oil viscosity, permeability, mode of flooding, and pressure gradient of the various field projects.

For most polymer floods with horizontal injectors, the highest possible Darcy velocity for various combinations of thickness, injection rate, horizontal well length, and well spacing is too low (in the range of ~0.01–0.2 ft/D) and unlikely to reach the onset velocity for viscoelastic behavior (i.e., >1 ft/D for most field conditions). For most vertical polymer injectors, less than 1% of the reservoir will experience fluid velocities high enough for viscoelasticity to potentially be important. Less-permeable reservoirs (<200 md) could experience the onset of shear thickening viscoelasticity at low rates (e.g., ~0.17 ft/D), but even so, a very small fraction of the reservoir is expected to achieve this onset flux. At a very short well spacing of 100 ft in the Pelican Lake polymer flood, the average velocity is ~1.7 ft/D. For an extreme case of a low thickness (10 ft), short horizontal well length (1,210 ft), and a small well spacing of 656 ft, an average velocity of ~1.2 ft/D and a pressure gradient of ~7.7 psi/ft were estimated for the Matzen field polymer flood. Although the average velocity is higher than the average onset flux rate, S_{or} reduction appears unlikely based on the macroscopic pressure gradients.

This paper conveys the improbability of shear-thickening induced-viscoelasticity causing S_{or} reduction in field applications. It also discusses the potential role of other effects for S_{or} reduction in existing polymer floods, including wettability alteration by the polymer and secondary-vs.-tertiary polymer-flooding effects. EOR researchers are advised to use realistic field-relevant fluxes during laboratory assessments while studying S_{or} reduction.

Introduction

Polymer flooding has historically been one of the most successful EOR methods used in depleted reservoirs to increase the recovery factor. The primary purpose of a polymer flood is to accelerate the recovery rate through improved sweep efficiency. Polymer flooding can improve microscopic, vertical, and areal sweep efficiencies by improving the mobility ratio (Seright 2017; Seright and Wang 2023). However, fractures or fracture-like features can severely compromise sweep efficiency for all types of floods if they directly connect injection wells to production wells (Seright and Brattekas 2021). For mitigating channeling through fractures or fracture-like features, gel treatments are often preferred (Seright 2003).

A conventional belief is that a polymer flood cannot recover the capillary-trapped residual oil beyond that of the waterflood. This belief is based on the classical capillary number concept which reveals that the amount of viscous force required to mobilize the residual oil trapped cannot be attained at a nominal flux of 1 ft/D using polymer solutions with a viscosity of 1–100 cp. A sample calculation provided by Azad (2021) illustrates this concept. (We caution here that the flux rate of 1 ft/D may not be representative of the major reservoir portion of the field, as will be shown later through an extensive set of reservoir engineering calculations performed for field applications.) To recover capillary-trapped residual oil, surfactant-polymer, alkaline-surfactant-polymer, or miscible floods are often proposed. In the past, normal polymer floods were often assumed to not mobilize significant capillary-trapped residual oil because polymers do not have a substantial effect on oil-water interfacial tension. Contrarily, using highly concentrated high-molecular-weight (Mw) polymer in the Daqing oilfield reportedly resulted in an incremental recovery factor of 20% of original oil in place (OOIP)—which was twice the value obtained during conventional polymer flooding in this field and comparable to recovery expectations for alkaline-surfactant-polymer flooding (Wang et al. 2011).

Daqing researchers attributed the additional oil recovery obtained using highly concentrated high-Mw polymer flooding to the polymer's viscoelastic character (Wang et al. 2000; Wang et al. 2007; Wang et al. 2001 , 2010, 2011; Wang et al. 2002). Since then, several

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polymer-flood experiments have been conducted at different laboratories across the globe to investigate the effect of polymer's viscoelasticity on oil recovery, especially the reduction of residual oil saturation (S_{or}). These studies include those conducted at The University of Texas at Austin (Ehrenfred 2013; Koh et al. 2016; Qi et al. 2017; Erincik et al. 2018; Jin et al. 2020), University of Alberta (Urbissinova et al. 2010; Azad and Trivedi 2020a, 2020b, 2021), New Mexico Tech (Seright 2011; Seright et al. 2018), Shell (Vermolen et al. 2014), Schlumberger (Clarke et al. 2016), and King Fahd University of Petroleum and Minerals (Barri et al. 2023). Research was also done to understand the polymer's viscoelastic aspects and S_{or} reduction through extensional rheology (Azad and Trivedi 2020a, 2021), microfluidics (Afsharpoor et al. 2012), and wettability altering methods (AlSofi et al. 2019a, 2019b; Li et al. 2020; Souayeh et al. 2022). Although some contradictions exist regarding the polymer's viscoelastic effect on S_{or} reduction [especially with heavy oil (Vermolen et al. 2014; Seright et al. 2018; Azad and Trivedi 2019a, 2019b)], many laboratory studies suggested potential positive effects of polymer's viscoelasticity on S_{or} reduction (Qi et al. 2017; Clarke et al. 2016; Erinick et al. 2017; Barri et al. 2023). Nevertheless, the most important unanswered question is whether conditions that resulted in significant S_{or} reduction in the laboratory are likely to be seen in the significant portion of the reservoir during field polymer-flooded projects. To answer this question, we examined polymer-flood projects conducted across nine countries (using both vertical and horizontal wells). We adopt two methodologies to answer the important question, "Are the field polymer EOR projects reaping the benefits of S_{or} reduction due to shear thickening induced-viscoelastic effects?"

In this paper, we commonly use the term "flux" (volumetric flow rate per unit of area), which is equivalent to "superficial velocity" or "Darcy" velocity. We recognize that some prefer the use of "interstitial" or "frontal" velocity. Others prefer to convert velocities in porous media to "effective shear rates," so that they may make a direct tie to viscosities measured in a viscometer. We prefer flux/superficial velocity/Darcy velocity because it is an easily measured and definitive quantity. Interstitial/frontal velocity can be easily calculated from flux if porosity and oil saturation are fixed and known. If porosity and especially oil saturation are not precisely known, uncertainty/variability may be introduced. Attempts to convert velocities in porous media to effective shear rates can especially become problematic since there are at least a dozen equations that purport to do this—which can introduce as much as an order of magnitude difference in estimated "shear rate" depending on which conversion equation is used (Cannella et al. 1988; Seright 1991).

Methodology

Two methodologies are used to analyze whether the polymer-flood projects conducted across the globe are experiencing S_{or} reduction due to viscoelastic effects.

Methodology 1: Comparison of Velocity in the Reservoir with the Viscoelastic Onset Velocity Predicted by Models or Observed in the Lab. In Method 1, the average Darcy velocity of the injected polymer solutions used in vertical and horizontal well projects is calculated (using Eqs. S-1 and S-2 and reported in **Table S-1** in the Supplementary Material). The shear thickening onset velocity (the velocity at which the polymer solution begins to exhibit a shear thickening behavior) of these polymer solutions in the relevant field conditions is extracted/determined using relevant in-situ rheological results and/or capillary bundle model (Table S-1). These two values are compared to project whether a given polymer-flood project experiences shear thickening. Furthermore, well spacing, well length, thickness, Darcy velocity, and permeability are varied to test scenarios where shear thickening might occur in the field. For vertical-well cases, the percent of the reservoir area that might experience shear thickening is estimated. Pressure gradients for these projects are also reported in Table S-1. For more details about the analyses, please refer to our supplementary attachment, especially Table S-1.

Method 2: Comparison with Representative Laboratory-Based Coreflood Experiments for *Sor* Reduction Potential. To compare the S_{or} reduction potential of the polymer systems under representative conditions, the Darcy velocity of the flood front in each of the compiled projects is tabulated (Table S-1). Laboratory coreflood experiments conducted at similar conditions from Table S-2 are examined to assess the possibility of the S_{or} reduction in a given field project. Table S-2 compiles several polymer-flood laboratory studies conducted across the globe, polymer-oil systems used, along with the flux rate, and the observed changes in oil recovery reported by different researchers. Besides ensuring the Darcy velocities in the laboratory and field conditions are similar, we also try to ensure that the oil viscosity, mode of flooding, formation nature, imposed or generated pressure gradient during polymer flooding, polymer concentration, and salinity in the laboratory closely resemble those for field conditions. In case there is a discrepancy between the laboratory and field conditions for any of the variables, logical reasons based on the rheology, and basic recovery concepts are given to justify our interpretations. We discuss the different field cases individually using the above methodologies.

Readers will be directed to a specific portion of the master Table S-2, and the readers are suggested to look at **Tables S-1 and S-2** in concert. Polymer-flood projects chosen from different countries are compared for their S_{or} reduction potential and discussed separately in the coming sections. Besides the macroscopic viscoelastic onset comparison, it is important to consider the S_{or} reduction potential due to other mechanisms (e.g., wettability alteration, secondary mode of flooding, and oil viscosity). The pore size distribution, initial wettability, and heterogeneity play a role in oil recovery during viscoelastic polymer flooding (Schneider and Owens 1982; Shiran and Skauge 2015; Morejan et al. 2019; Barri et al. 2023; Dafaalla et al. 2025). However, these parameters are not considered during our discussions (primarily because of a lack of relevant information for the specific fields and projects).

Polymer-Flood Projects

Project 1: Milne Point Polymer-Flood Project in Alaska, USA. This project is operated by Hilcorp in Alaska, USA.

Methodology 1. In the J-Pad part of this project, the horizontal injection wells are 5,000–5,400 ft long (Table S-1). The injection rate is between 700 B/D and 1,400 B/D. The thickness is about 14 ft. The average Darcy velocity calculated using Eq. S-1 is between 0.05 ft/D and 0.12 ft/D (Table S-1). Despite the low thickness of the reservoir, a lengthy horizontal well ensures that there is enough flow area to keep the velocity low. The onset velocity for shear thickening for the given injection conditions is 0.43 ft/D. Consequently, the average Darcy velocity in the field is always lower than the onset velocity for shear thickening. Therefore, the possibility of shear thickening-induced S_{or} reduction is negligible. The pressure drops between the injection and production wells are 1,000 psi and the interwell distance is 1,179 ft. The average pressure gradient is 0.85 psi/ft. A sensitivity study was done by varying the interwell distance on the pressure gradient, as shown in **Fig. 1a**.

Methodology 2. Despite the average velocity being lower than the onset rate, other factors may influence the possibility of S_{or} reduction at Milne point conditions. These include high oil viscosity, low-salinity polymer injection, possible wettability alteration, and extremely low-pressure gradient associated with larger well-spacings **(Fig. 1a)**.

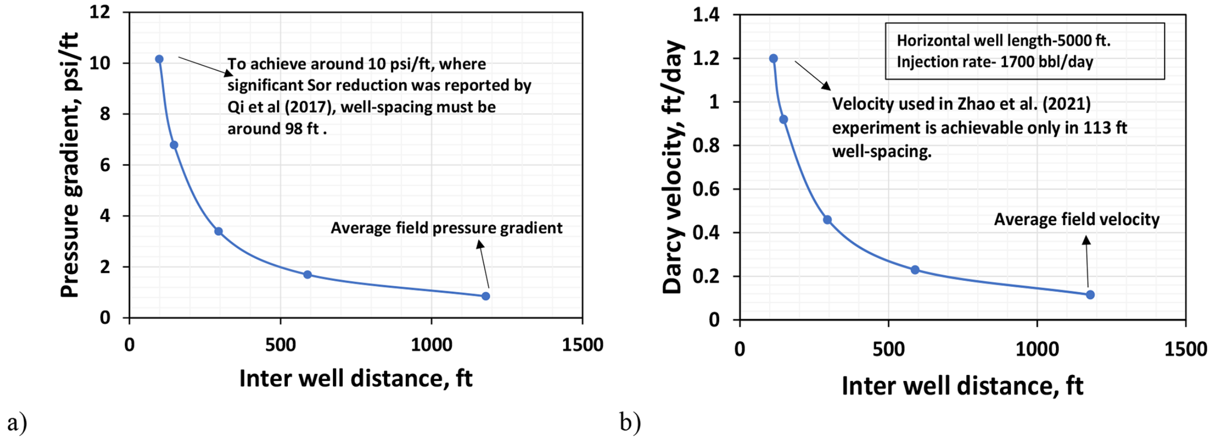

Fig. 1—Effect of interwell spacing on the (a) pressure gradient and (b) Darcy velocity under Milne point conditions.

To analyze the effects of these variables under more representative conditions, a closer comparison can be made with the laboratory studies performed by Zhao et al. (2021). The polymer solutions used at the Milne Point project were 1,200–1,750-ppm SNF Flopaam 3630 HPAM with 2,500-ppm total dissolved solids (TDS). The average permeability of the reservoir pattern examined is 1,200 md and the oil viscosity is 202 cp. To reduce uncertainties associated with whether the recovered oil is residual oil, consider Zhao's experiment performed with the sequential injection of 2,300-ppm HPAM at 27,500-ppm TDS salinity, followed by 1,400-ppm HPAM injection at 2,498-ppm TDS salinity in a 1,770-md unconsolidated sandpack (Row 22 of Table S-2). Examination of Fig. 10 in Zhao et al. (2021) conveys that a plateau in oil recovery occurs during extended high-salinity polymer injection. Therefore, the subsequent low-salinity polymer injection appears to reduce the S_{or} by 0.07 saturation units (22nd row of Table S-2). Refer to Azad and Seright (2024) for more information about the conditions required for driving the oil saturation closer to residual oil saturation. Zhao et al. suggested that polymer provides mobility control and low-salinity reduces S_{or}. A Darcy velocity of 1.2 ft/D is imposed in all of Zhao's experiments, which is almost 10 times higher than the maximum Milne Point velocity (Row 1 of Table S-1). For the Milne Point flood to achieve the Darcy velocity used in Zhao et al.'s experiments, the interwell spacing must be less than 113 ft **(Fig. 1b)**.

At the Darcy velocity of 0.2 ft/D, Qi et al. (2017) performed coreflood experiments with 600-ppm and 1,800-ppm 3630 HPAM at two different salinities of 11,000-ppm TDS and 400-ppm TDS, respectively in 2,100–2,200-md sandstone cores saturated with 120-cp oil (listed in Row 1 of Table S-2). Polymer concentration and Mw used in the Milne Point project are similar. The salinity range used in the work of Qi et al. brackets the salinity injected at Milne Point. Importantly, the flux rate in the work of Qi et al. is 0.2 ft/D, which is closer to the calculated maximum Darcy velocity of 0.12 ft/D (Tables S-1 and S-2). Row 1 of Table S-2 indicates that, at the lowest flux and pressure gradient, high-salinity polymer injection does not result in any S_{or} reduction. However, low-salinity polymer injection may reduce the S_{or} slightly—by 0.003 to 0.013 units. Wettability alteration conceivably may have enhanced spontaneous imbibition during low-salinity polymer injection in oil-wet (Rows 14 and 16 in Table S-2) carbonates. Table S-2 suggests that polymer-induced wettability alteration could occur in both oil-wet (Row 16) and water-wet rocks (Row 21). However, we cannot definitively conclude that Milne Point conditions cause slight S_{or} reduction because the oil used by AlSofi et al. (2017), Souayeh et al. (2022), and Amiri et al. (2017) was 2–17 cp (i.e., 2–20 times lower than the Milne Point oil viscosity). In general, the higher the oil viscosity, the lower the low flux recovery during cocurrent spontaneous imbibition (Fischer et al. 2008; Meng et al. 2017) (Row 23 in Table S-2). Interestingly, even with a forced injection of 0.66 ft/D Darcy velocity, Vermolen et al. (2014) reported that 300-cp heavy oil cannot be mobilized even at high-pressure gradient, whereas 9-cp oil can be mobilized (Row 2 in Table S-2). This suggests that residual heavy oil mobilization is a difficult task. The imposed pressure gradient in Qi et al. was 3 psi/ft, which is significantly higher than the average pressure gradient of 0.85 psi/ft at Milne Point. At high flux-pressure conditions of 7.6 ft/D and 10 psi/ft, Qi et al. (2017) noticed a reduction in S_{or} from 0.31 to 0.21 (Row 1 in Table S-2). However, Milne Point can achieve 10 psi/ft only if the wells are spaced within 30 m (98 ft) **(Fig. 1a)**. Even then, the oil viscosity is higher (202 cp) at Milne Point. This contrasts with 120-cp oil used by Qi et al. and thereby diminishing the possibility of Sor reduction.

Is there any scenario where low-pressure gradient and flux will be conducive to the reduction of capillary-trapped oil by injection of viscoelastic polymer solutions? Ehrenfred (2013) reported that even at a pressure gradient of 1.5 psi/ft and Darcy velocity of 0.03 ft/D (in 1,576-md Boise core), an S_{or} of 0.329 was attained during secondary polymer flooding—a value comparable to tertiary polymer flooded S_{or} of 0.327 in 1,551-md Boise core—but at the high flux and pressure gradient conditions of 0.25 ft/D and 14.81 psi/ft (Row 11 of Table S-2). The oil used in both experiments was the same (oil viscosity of 300 cp) so, the possibility of S_{or} reduction appears to be relatively higher for an extended distance in the reservoir when the flooding is operated in the secondary mode. The reason behind this could be that once the trapping occurs, it becomes difficult to mobilize, which is in accordance with the theory suggested by Huh and Pope (2008).

Therefore, it appears that lengthy horizontal wells and large well spacings preclude the possibility of shear thickening–induced viscoelasticity to reduce S_{or}. Furthermore, the higher oil viscosity coupled with tertiary flooding mode appears to hinder other S_{or} reduction possibilities under Milne Point conditions. More studies are needed, taking into account wettability alteration and spontaneous imbibition studies in cocurrent and countercurrent modes along with the development of capillary desaturation curves (CDCs) for representative conditions.

Project 2: Pelican Lake Polymer Flood. This field is located in Alberta province, Canada, and was operated by EnCana (Cenovus) and CNRL.

Methodology 1. The horizontal well lengths in the project range from 4,922 ft to 8,203 ft (Table S-1) (Delamaide 2021a). The reservoir thickness ranges from 3.28 ft to 29.5 ft. The injection rates range from 126 B/D to 755 B/D. The highest, middle, and lowest average Darcy velocities for the possible combinations of injection rate, thickness, and well length (Table S-1) were 0.26 ft/D, 0.03 ft/D, and 0.003 ft/D, respectively, for a well spacing of 656 ft (Table S-1). The onset of the shear thickening for these permeable sands is 4–6 ft/D.

This indicates that the velocities (even in the thinnest portion of the reservoir with minimally used horizontal length and maximum injection rate) are less than the shear thickening onset velocity; and therefore, the possibility of viscoelastic shear thickening to reduce S_{or} is negligible.

At Pelican Lake, well spacing also varies (Delamaide et al. 2014; e.g., 98 ft, 164 ft, and 656 ft). The pressure gradients corresponding to these spacing values are 1.3 psi/ft, 5.4 psi/ft, and 9 psi/ft, respectively. The pressure gradient as a function of well spacing is plotted in **Fig. 2a**.

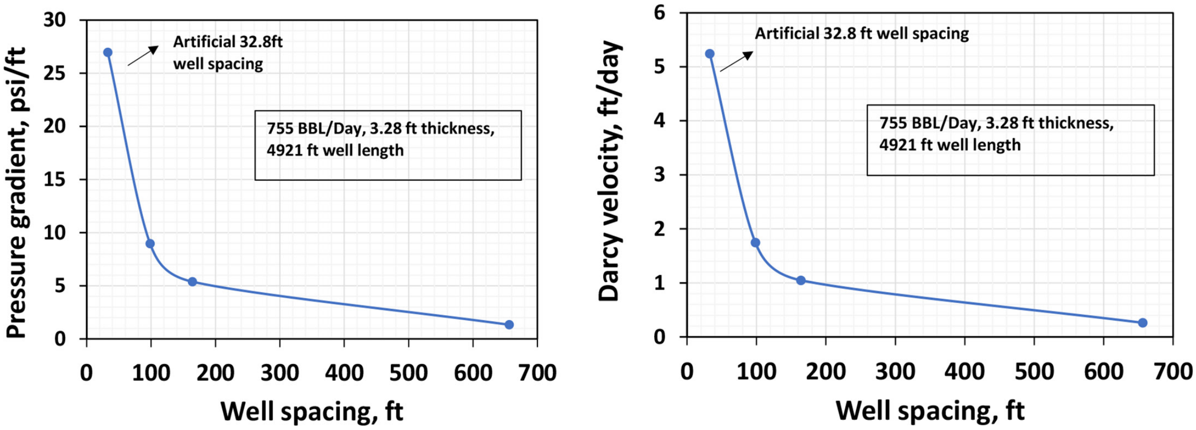

Fig. 2—(a) Pressure gradient and (b) Darcy velocity as a function of various well spacing for Pelican Lake conditions, including the artificial case of 32.8 ft.

The velocity calculation for horizontal wells in Eq. S-1 does not incorporate well spacing. To account for reduced well spacing, we related the pressure drop with well-spacing distance to find the increase in velocity. For reduced well spacing of 164 ft and 98 ft, velocities are 1 ft/D and 1.7 ft/D, respectively—compared with 0.26 ft/D for well spacing of 656 ft. In these calculations, low thickness and high injection rate were chosen to maximize the possible Darcy velocity under Pelican Lake conditions. Darcy velocity as a function of reduced well spacing is plotted in **Fig. 2b**. From these sensitivity studies, not even 98.4-ft well spacing experiences a velocity value that is close to the shear-thickening onset rate of 4 ft/D. A 32.8-ft well spacing would result in a velocity of 5.3 ft/D, as shown in **Fig. 2b**. Therefore, the possibility of S_{or} reduction is negligible, even with the closest well spacing.

Methodology 2. To assess whether conditions at Pelican Lake are conducive to S_{or} reduction due to nonshear thickening phenomenon, we must consider other pertinent variables such as flux, pressure gradient, oil viscosity, and mode of flooding.

The most common well spacing is 656 ft at Pelican Lake. Therefore, a flux of 0.26 ft/D and a pressure gradient of 1.54 psi/ft are typical at Pelican Lake. Notably, 1,000-ppm 3630 HPAM at a salinity of 6,811-ppm TDS is used, and the oil viscosity ranges from 800 cp to 80,000 cp (Delamaide et al. 2014). Qi et al. (2017) reported no significant S_{or} reduction during the tertiary injection of 600-ppm Flopaam 3630 HPAM in 400-ppm TDS brine in a core saturated with 120 cp oil at 0.2 ft/D and pressure gradient of 3 psi/ft (Row 1 in Table S-2). At realistic horizontal well spacing, Pelican Lake conditions do not reach the pressure gradient sufficient to reduce S_{or}. However, if we consider the shorter well spacings of 164 ft and 98 ft, respectively **(Figs. 2a and 2b)**, the pressure gradient increases to 5.4 psi/ft and 9 psi/ft, respectively. For comparison, Qi et al. (2017) performed experiments at the 10-psi/ft pressure gradient. Although S_{or} reduction of ~0.1 saturation units was observed at 10 psi/ft (Row 1 in Table S-2), two additional factors should be considered because the viscoelastic influence on S_{or} reduction also depends on the oil viscosity and mode of flooding (Azad and Trivedi 2019a). We note that Abrams (1975) modified the capillary number by incorporating oil viscosity to improve the S_{or} correlation with oil viscosity.

Influence of Oil Viscosity. At Pelican Lake, the oil viscosity ranges between 800 cp and 80,000 cp. Several researchers did not report a significant S_{or} reduction with heavy oil of 300–1,200 cp at fluxes of 0.2–1 ft/D (Azad and Trivedi 2019a; Seright et al. 2018; Vermolen et al. 2014). Seright et al. (2018) reported that 1,260-cp heavy oil can be mobilized as the flux increases from 1 ft/D to 17 ft/D (Row 4 in Table S-2). However, under Pelican Lake conditions, flux values this high are not achieved even with short well-spacing of 98 ft and lengthy horizontal wells **(Fig. 2b)**. A careful look into the work of Koh et al. (2016) (Row 17 of Table S-2) indicated that a tertiary polymer flood (using 1,200-ppm Flopaam 3630 HPAM) at ~0.35 ft/D into 6,078–7,900 md unconsolidated media can reduce the mobile oil saturation by 0.12–0.34 saturation units. Thus, a saturation change of 0.34 appears achievable for 1,050-cp oil. Does this mean that Pelican Lake reservoir may reap the benefits of S_{or} reduction?

There are two complicating factors. First, a flux of 0.35 ft/D was used by Koh et al., whereas with a well spacing of 656 ft, the average Pelican Lake flux is 0.26 ft/D. For short well spacings of 98 ft and 164 ft, 1 ft/D is achievable. However, an important question is whether the oil recovered in the work of Koh et al. is a truly well-swept residual oil. **Fig. 3a** reveals that less than 2 PV of water were injected during the corefloods performed by Koh et al. (2016) and a definitive S_{or} was not attained, especially in those floods carried out with relatively heavy oil (120 cp and above). Thus, a significant amount of mobile oil may remain if the oil is heavy. There is no definitive volumetric throughput to attain a true S_{or} **(Figs. 3a through 3f)**. It depends on the permeability, oil viscosity, and so on, and the readers are suggested to refer to the Supplementary Material for details. Any mobile oil present before viscoelastic polymer injection means, we cannot say it is a true residual oil saturation. Koh et al. neither injected glycerin nor injected much pore volume of water **(Fig. 3a)**, and therefore, the higher reduction in oil saturation observed by Koh et al. cannot justify a claim that polymer's viscoelastic effect reduces well-swept S_{or} under Pelican Lake conditions.

An interesting feature of the Pelican Lake project is that all three modes of production were implemented. **Fig. 4** [extracted from Delamaide (2021a)] shows that the secondary mode of injection results in a higher recovery factor than the tertiary flooding mode and primary production. Almost 40% of OOIP was achieved in the secondary flooding mode.

Delamaide (2021a) reported a recovery factor of up to 48% with 1.56 PV secondary polymer injection for 98-ft well spacing. This is not shown in the above figure due to scaling. The questions arise: What causes the high recovery factor during secondary injection, and can the additional recovery be attributed to enhanced S_{or} reduction from viscoelastic effects at short spacing?

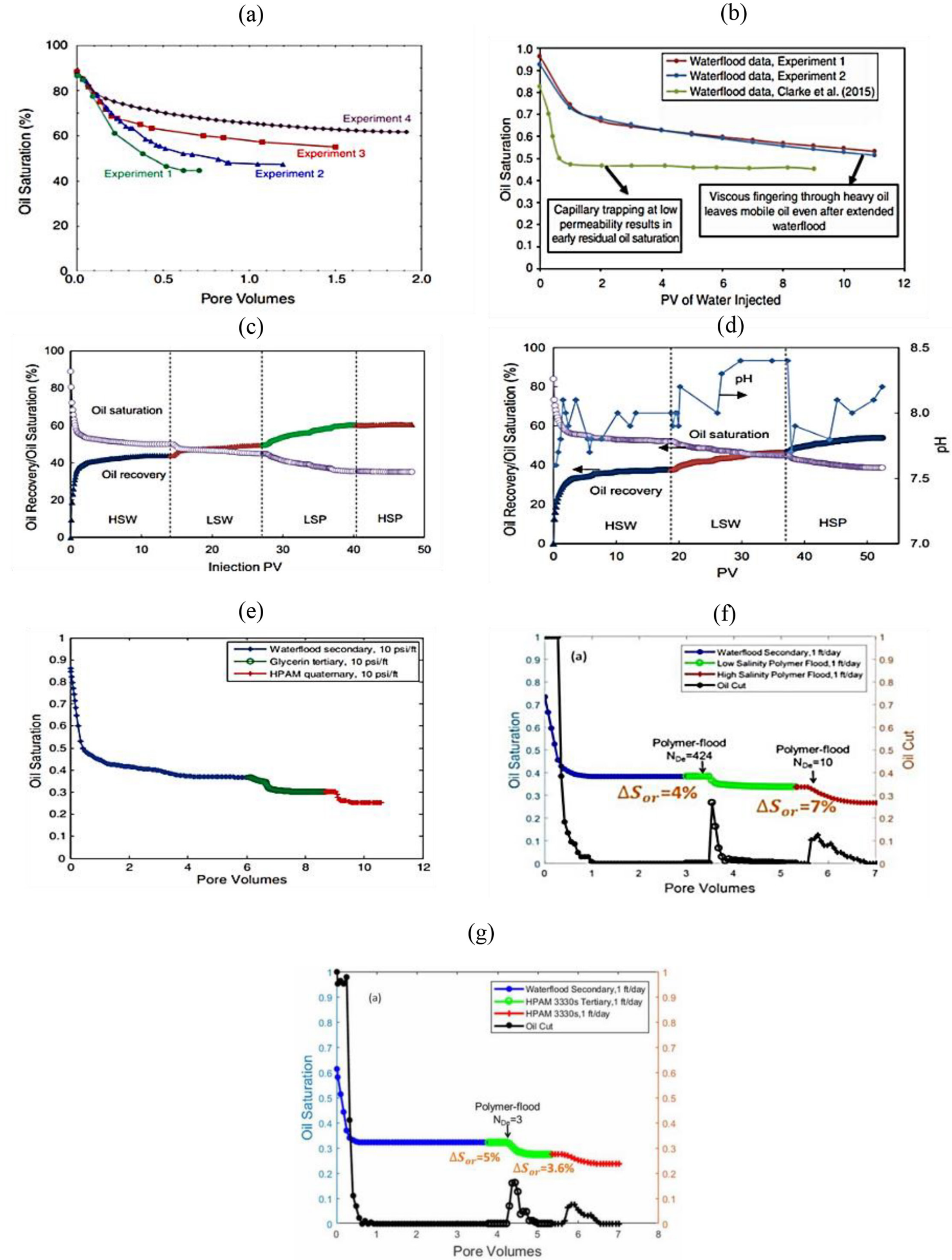

Fig. 3—Oil recovery profile during water injection. Extracted from (a) Koh et al. (2017); (b) Azad and Trivedi (2020b), Clarke et al. (2015); (c) Zhao et al. (2020); (d) Zhao et al. (2020); (e) Qi et al. (2017); (f) Jin etal. (2020); and (g) Jin et al. (2020).

As discussed previously with 300-cp heavy oil, tertiary polymer flooding does not appear to result in S_{or} reduction even at 0.22–0.66 ft/D, whereas, at similar conditions, 9-cp oil was displaced by tertiary viscoelastic polymer injection (Row 2 of Table S-2). To consider whether secondary flooding under Pelican Lake conditions caused higher recovery, Azad and Seright (2024) examined (a) a set of experiments performed by Cottin et al. (2014), Wang (1995), Wreath (1987) and (b) a set of experiments performed by Ehrenfred (2013). Azad

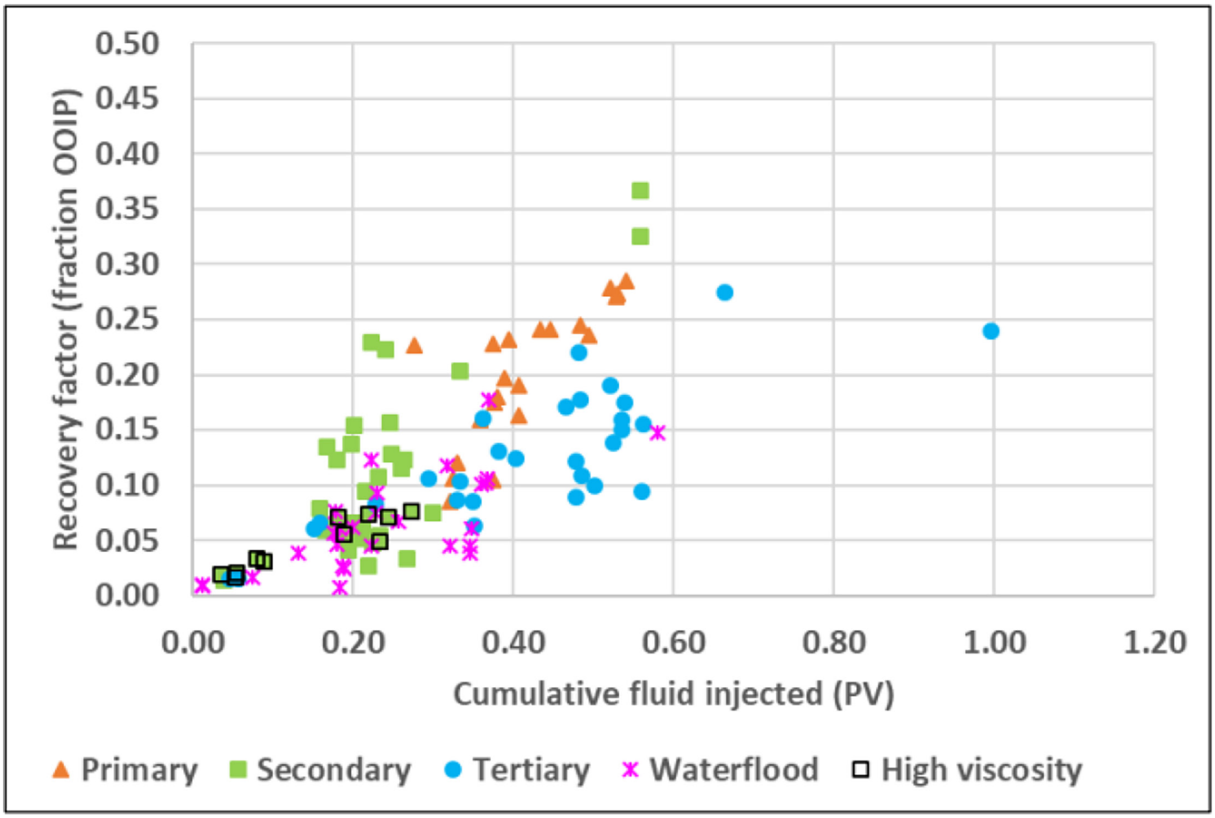

Fig. 4—Comparison of primary, secondary, and tertiary recovery factors during the Pelican Lake polymer-flood project (from Delamaide 2021a).

and Seright (2024) noted that a secondary mode of injection appears to recover heavy oil more effectively than light oil at low-flux and -pressure gradients.

The better performance of relatively low-flux heavy oil secondary polymer flood in high-permeability media could be due to the prevention of snap-off. During the secondary mode of polymer injection, oil exists in the mobile state with relatively lower trapping pressure. Snap-off is due to trapping, and trapping is related to capillary pressure, which in turn is related to pore-throat radius (the value of which is governed by permeability). Therefore, it is imperative to consider the effect of permeability on heavy oil recovery during secondary flooding.

Effect of Permeability. *Possible Prevention of Snap-Off Effects.* For 328-ft and 164-ft spacings, the average Darcy velocity at Pelican Lake is 1.04 ft/D and 1.74 ft/D. These velocities are lower than the onset for shear thickening of 4 ft/D in 3,480-md rock. However, the permeability of the Pelican Lake ranges from 300 md to 5 darcies. A low permeability will reduce the onset rate (for shear thickening), and conceivably, macroscopic viscoelastic effects might be amplified in certain low-permeability regions if 98-ft well spacing is used (where a Darcy velocity of 1.74 ft/D is expected). Incidentally, with a close well spacing of 98 ft, a very high recovery factor of 48% was reported during a secondary mode injection (Delamaide 2021b). Ehrenfred (2013) performed an experiment at a Darcy velocity of 0.03 ft/D, which is almost nine times lower than the velocity for the closest Pelican Lake well spacing. Consequently, snap-off prevention may be a possibility during the secondary mode. However, more work is needed to assess this possibility. We suggest performing coreflood experiments at Pelican Lake conditions in both secondary and tertiary modes to see if there is an early onset of rapid oil mobilization in the secondary mode (i.e., a possibility of lower critical capillary number in the secondary mode than the tertiary mode). If so, how much reduction in pressure gradient and flux can be expected during the secondary mode of injection? A detailed CDC must be generated for both secondary and tertiary polymer floods under Pelican Lake conditions. To better understand the role of strong trapping on secondary residual oil mobilization, one should perform a similar set of secondary and tertiary experiments in porous media that represent the range of permeabilities present in the intended application.

Project 3: East Messoyakhskoe Long Horizontal Well Case. East Messoyakskoe is one of the northernmost fields in Arctic Russia. The field is operated by Gazprom and Rosneft. For the well length, injection rate, and thickness ranges (Ilyasov et al. 2020 and Table S-1), the average Darcy velocities in this field are 0.03 ft/D, 0.02 ft/D, and 0.01 ft/D, respectively **(Fig. 5a)**. The pressure gradients calculated using the related well spacings are 1.52 psi/ft and 0.76 psi/ft, respectively **(Fig. 5b)**.

Methodology 1. The onset value for these conditions (assuming salinity of 3,000-ppm TDS) is predicted to be 0.9 ft/D for the 5,000-md case, 0.63 ft/D for the 2,525-md case, and 0.09 ft/D for the 50-md case. These values are lower than the calculated Darcy velocity, and hence the macroscopic shear thickening will not influence these thick reservoirs that use long horizontal wells.

Methodology 2. Oil viscosity in this field is about 111 cp. The porosity value is 0.29 (Row 3 of Table S-1). Qi et al. (2017) performed tertiary polymer-flood experiments in a ~2,000-md sandstone core saturated with 120-cp oil at 0.17–0.2 ft/D. The authors did not observe noticeable S_{or} reduction with either low- or high-salinity polymer injections (Row 1 of Table S-2). For 120-cp oil, a pressure gradient of 23.8 psi/ft is generated by 2,000-ppm Flopaam 3630 HPAM (in 1,400-ppm TDS brine) to mobilize the 120-cp oil at the Darcy velocity of 0.24 ft/D (Row 8 in Table S-2). As the calculated pressure gradient (1.52 psi/ft and 0.76 psi/ft) is much lower, the possibility of S_{or} reduction is nil. The highly viscous nature of the oil means that the possibility of wettability-induced alteration or low flux recovery is

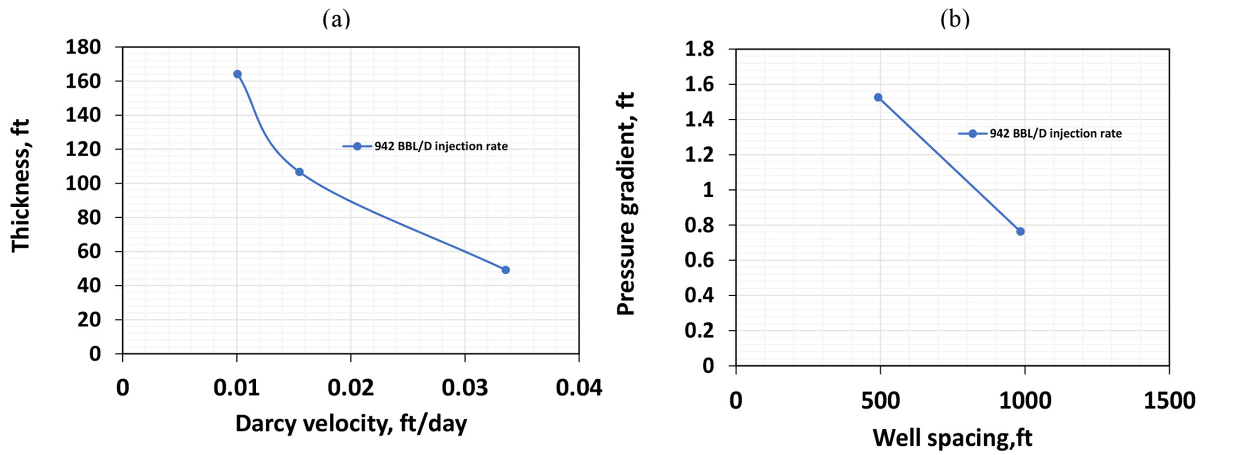

Fig. 5—(a) Darcy velocity as a function of thickness and (b) pressure gradient as a function of well spacing for East Messoyahskoe polymerflood project, Russia.

reduced (Rows 23 and 24 of Table S-2). Please refer to our discussion about wettability alteration and low flux recovery associated with the Milne Point project where the oil viscosity is similar to that of the East Messoyahskoe field.

The large well-spacing, lengthy horizontal wells, high oil viscosity, and high average thickness keep the velocity and average pressure gradient low in this East Messoyahskoe field. Based on the available information, the possibility of S_{or} reduction is negligible in this field.

Project 4: Matzen Short Horizontal Well Case. The Matzen oil field is located in Austria. The field is operated by OMV.

Methodology 1. Rock and fluid properties for this project are extracted from Janczak et al. (2021) and Hwang et al. (2022). The length of a horizontal well in this project ranges from 1,210 ft to 2,625 ft, which is short relative to the previously discussed cases of Milne Point and Pelican Lake. The injection rate is 2,516 B/D. Although the average thickness is 66 ft, the minimum value is 10 ft. The average Darcy velocity calculated for the lowest and the average thicknesses and varying horizontal well lengths are plotted in **Fig. 6a**.

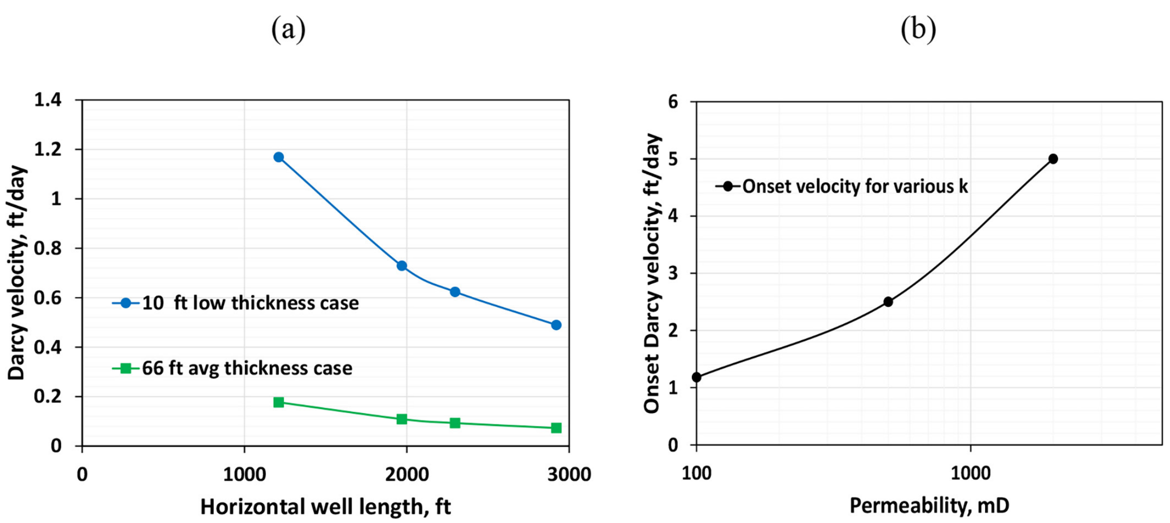

Fig. 6—(a) Effect of horizontal-well length on Darcy velocity for the thicknesses of 10 ft and 66 ft under Matzen conditions. (b) Predicted onset velocity for different permeabilities.

In this reservoir, permeability ranges between 100 md and 2,000 md. However, for reservoirs with multiple layers, velocity will necessarily be lower in less-permeable layers. Is there any predicted onset velocity for different permeability that falls within the range of velocity calculated for different horizontal well lengths and thicknesses? We are interested in this comparison as the horizontal well length is relatively short in this project. To answer this, we consider three different permeabilities of 100 md, 500 md, and 2,000 md for finding shear thickening onset values for polymer systems used in Matzen conditions. These values are reported in Table S-1. Fig.6a and Fig.6b compares the predicted onset values with the calculated Darcy velocities.

In the extreme case of a short horizontal well length of 1,211 ft and 10-ft thickness, the Darcy velocity reaches around 1.2 ft/D. For low-permeability rocks of 100 md, the predicted onset velocity is 1.18 ft/D, which is similar to the average velocity seen for the optimal case of low thickness and short horizontal well length. Therefore, this appears to be one scenario, where the average velocity of the reservoir is close to the shear thickening onset values. However, in those regions having higher permeability and thickness and those developed using lengthier horizontal wells, the calculated velocity is lower than the onset velocity, signifying that viscoelastic effects may not manifest macroscopically throughout the entire reservoir region. Another important point to highlight is that fractures are created in these scenarios and, if they are accounted for, then the velocity would actually be significantly lower than considered here.

Methodology 2. In this section, we assess whether the polymer-flood conditions in the Matzen field are reaping the benefits of S_{or} reduction due to the other mechanisms by comparing with the relevant laboratory-scale findings.

The polymer system for this case is 1,000-ppm Flopaam 3630 HPAM in 20,000-ppm TDS brine. The oil viscosity in this field is about 16 cp. The porosity is about 0.22 (Table S-1). As discussed before, in the extreme case of a short horizontal well length of 1,211 ft and 10-ft thickness, the Darcy velocity reaches around 1.17 ft/D **(Fig. 6b)**. For 10-ft thickness, the velocity ranges from 0.5 ft/D to 0.7 ft/D for well lengths ranging from 1,969 ft to 2,920 ft. For 66-ft thickness, the velocity ranges between 0.1 ft/D and 0.07 ft/D **(Fig. 6b)**. Several researchers reported significant S_{or} reduction during viscoelastic polymer flood at 0.2-ft/D Darcy velocity (Clarke et al. 2016; Qi et al. 2017; Rows 1 and 9 of Table S-2).

Because the oil viscosity at Matzen is only 16 cp, and because S_{or} reduction is easier with light oil than heavy oil (Abrams 1975), a short horizontal well length coupled with low thickness may allow some S_{or} reduction. We caution that only higher velocities are observed in the low-thickness region. If the thickness exceeds 66 ft, the velocity is reduced below 1 ft/D, which raises doubt regarding possible S_{or} reduction in most parts of the reservoir. Residual oil must be mobilized for a long distance without retrapping, so the reduction in the velocity may negate any benefit. Moreover, there are few experiments reported in the laboratory where researchers have imposed a Darcy velocity of less than 0.2 ft/D. Even for those who report coreflood experiments with a flux rate of around 0.1–0.2 ft/D, no S_{or} reduction was observed (Qi et al. 2017), especially at high-salinity injection conditions (Row 1 in Table S-2) unless it is operated in the secondary mode in high-permeability media (Row 11 of Table S-2; Ehrenfred 2013). For well spacings of 328 ft and 656 ft, pressure gradients are 3.84 psi/ft and 7.7 psi/ft, respectively. At 10 psi/ft, S_{or} reduction was reported in the laboratory, whereas at 3 psi/ft, no significant S_{or} reduction was reported, especially for high-salinity polymer injection conditions (Row 1 of Table S-2). This indicates that most of Matzen's reservoir may not reap the benefits of S_{or} reduction. Row 8 of Table S-2 indicates that high-salinity polymer flood performed at the Darcy velocity of 0.48 ft/D could lead to higher S_{or} reduction by around 0.2 saturation units (Erincik et al. 2018). However, these velocities are achievable only at low thickness. Also, it is also important to highlight that Erinick's high recovery factors applied to high-salinity polymer injection at 30.6 psi/ft using cores that were preflooded with low-salinity polymer systems and treated with EDTA (Row 8 of Table S-2)—so they may not be representative of a practical application. Therefore, it should not be considered evidence for possible S_{or} reduction under Matzen conditions.

Wettability alteration is worth considering because Matzen's oil viscosity is relatively low (i.e., 13 cp). With light oils, AlSofi et al. (2019a), Souayeh et al. (2022), and Al-Busaidi et al. (2023) reported a wettability alteration using ATBS-PAM polymers and HPAM at low salinity in oil-wet carbonates (Rows 14, 16 and 20 of Table S-2). Amiri et al. (2022) reported that polymer could alter the wettability even in water-wet rocks. Souayeh et al. (2022) performed wettability alteration measurements at 19,000-ppm TDS salinity and reported a significant reduction in contact angle (Row 16 of Table S-2). Wettability alteration could perhaps occur during polymer injection under Matzen's conditions. However, Souayeh et al. (2022) reported that the imbibition recovery for 500-ppm SAV 10 MPM polymer (with 19,000-ppm TDS) was only 22%, in contrast to 46% obtained with the same polymer system at 1,960-ppm TDS salinity. This raises a concern regarding high-salinity polymer injection. Clemens et al. (2016a, 2016b) reported a 5–10% incremental recovery in the 8-TH reservoir of the Matzen field. The incremental recovery factor is not very high when compared to that reported for Daqing because polymer injection was initiated in this heterogeneous field at high water cut of 96%. The authors reported that 20% of the recovery could be attributed to the acceleration along the flow path and 80% to the increase in sweep efficiency (Clemens et al. 2016). The higher water cut of 96% may mean that the oil is not well-swept. Capillary trapping may lead to some discontinuity in the oil. It is difficult to comment whether S_{or} reduction occurred. Direct experimentation using Matzen conditions is suggested along with the development of CDCs.

Project 5: Chinese Vertical Well Cases. In this section, polymer-flood projects conducted in various Chinese fields are considered, such as the Shengli, Xinjian, Bohai, and Daqing oil fields.

Methodology 1. Rock and fluid properties are extracted from Guo et al. (2021). The shear thickening onset rate was estimated for these fields and ranges from ~0.17 ft/D to 0.67 ft/D (Table S-1). The average of Darcy velocities in Gucheng, QD1, Bohai, DAQING SRP, and DAQING APP are 0.03 ft/D, 0.01 ft/D, 0.02 ft/D, 0.01 ft/D, and 0.02 ft/D, respectively (Table S-1). The effect of radial distance from the wellbore on Darcy velocity is plotted for all five cases **(Fig. 7a)**. The percentages of the radial reservoir portion experiencing a velocity greater than the onset velocity are provided in **Fig. 7b**.

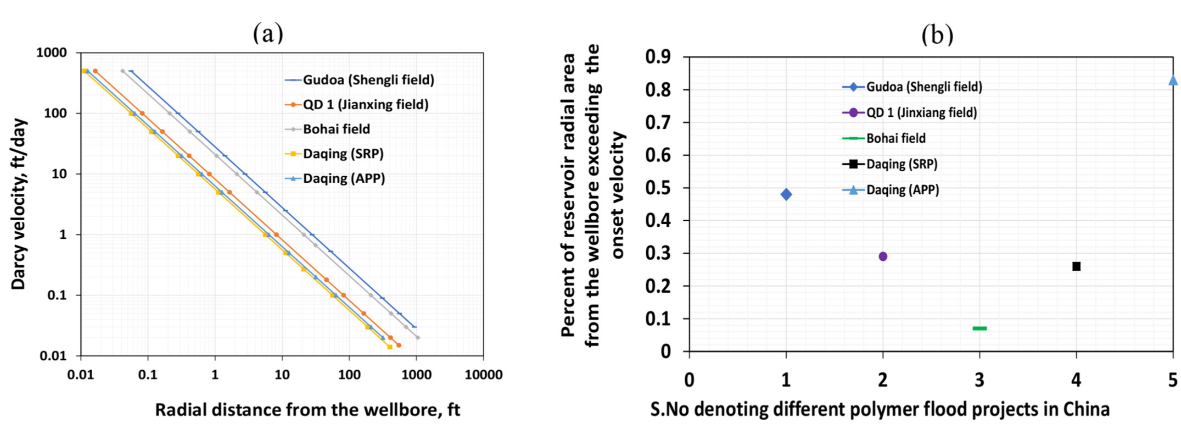

Fig. 7—(a) Effect of radial distance from the wellbore on Darcy velocity for five Chinese polymer-flood projects. (b) Percent of the radial area of Chinese reservoirs exceeding the onset velocity for shear thickening (S.no means serial number).

This result strongly suggests that viscoelastic shear thickening does not play a role in reducing S_{or} in any of the Chinese polymer-flood projects reported by Guo et al. (2021).

Methodology 2. Excluding Gudao ZYQ of the Shengli field, the incremental oil recovery factors (IORFs) of DAQING-SRP and DAQING-APP are much higher than in other cases **(Fig. 8a)**. These cannot be decoded with a similar average Darcy velocity that ranges between 0.01 ft/D and 0.03 ft/D (Table S-1 and **Fig. 8b**). The question arises why the Daqing oil field yields a higher recovery factor. To

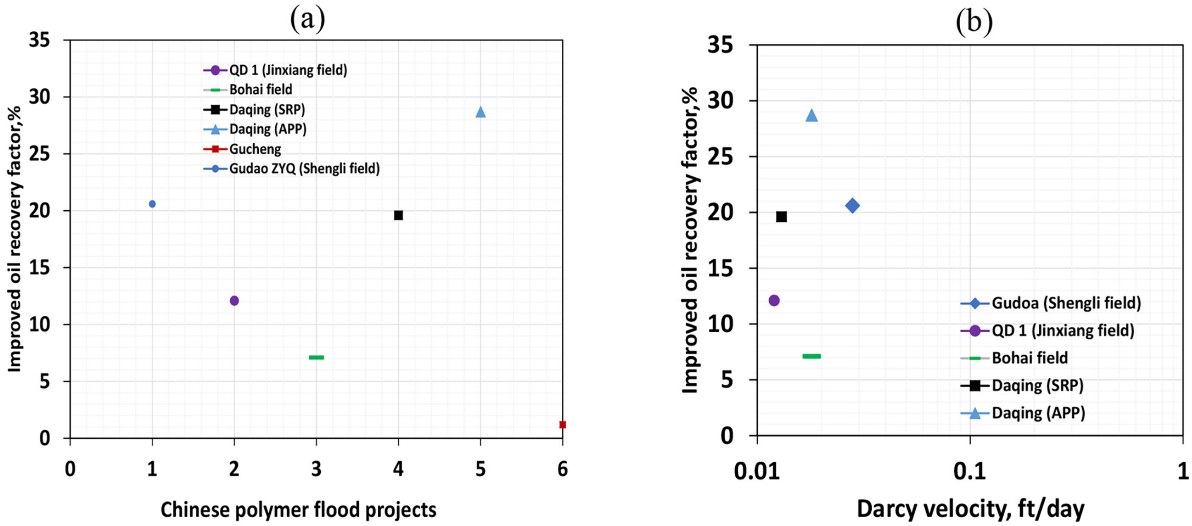

Fig. 8—(a) IORF for Chinese polymer-flood projects (from Guo et al. 2021). (b) Improved oil recovery factor as a function of Darcy velocity for Chinese polymer-flood projects (Guo et al. 2021).

address this question, variables pertinent to oil recovery, such as pore volume of polymer injected, polymer dosage (polymer concentration times pore volume injected), well spacing, oil viscosity, polymer/oil viscosity ratio, for these cases must be analyzed. **Figs. 9a and 9b** convey that the larger the pore volume injected **(Fig. 9a)** and the larger the polymer dosage **(Fig. 9b)**, the higher the IORF. A higher dosage is associated with higher polymer concentration, and higher concentration generally provides not only higher viscosity but also a stronger wettability alteration (Li et al. 2020; Amiri et al. 2022). Does that mean a high concentrated polymer flood is capable of altering wettability and provides an S_{or} reduction and better oil recovery at Daqing? If that is the case, then the case of Gucheng contradicts the trend "the higher the dosage and pore volume, the higher the IORF" (**Figs. 9 and 10**). The reason for this contradiction may be the higher oil viscosity (700 cp) and lower polymer-oil viscosity ratio associated with Gucheng. Even with 300-cp oil, no S_{or} reduction was reported by Vermolen et al. at a Darcy velocity of 0.66 ft/D (Row 2 in Table S-2), whereas for 9-cp light oil, Vermolen et al. (2014) reported an S_{or} reduction of 0.05 units at 0.66 ft/D at 100.6 psi/ft while injecting a viscous polymer slug. This supports the impossibility of S_{or} reduction in the Gucheng field.

The lower the oil viscosity, the better the recovery during spontaneous imbibition (Fischer et al. 2008; Meng et al. 2017). Despite that, the low recovery associated with QD1 (characterized by the lower oil viscosity of 5.13 cp) could be attributed to larger well spacing **(Fig. 10a)**. This suggests that well spacing is important even if the variation in well spacing and injection rate results in a similar average velocity in all the cases **(Fig. 8b)**. Furthermore, the lower IORF in QD1 indicates that, despite the favorable conditions [such as lower oil viscosity and low salinity (Table S-1)] for wettability alteration, other mechanisms such as retrapping (Spildo et al. 2012) and reduced localized extensional effect (Azad and Trivedi 2021) may eliminate S_{or} reduction for large spacings. Therefore, three typical conditions associated with the Daqing SRP polymer flood appear to benefit oil recovery at low velocities. They are (a) usage of highly concentrated, low-salinity polymer solutions (1,300–1,500 ppm Flopaam 3630 in 5,000–5,500-ppm TDS salinity), (b) relatively low oil viscosity (9-cp oil), and (c) low (dense) well spacings. Low well spacings amplify the localized viscoelastic effects (Azad and Trivedi 2021) and may reduce retrapping.

Is there any laboratory evidence that the usage of highly concentrated, low-salinity polymer solutions and low viscous oil could alter the wettability to increase S_{or} reduction? Table S-2 suggests that, in general, (a) the higher the concentration, the higher the wettability alteration (Rows 15, 16, and 21 of Table S-2); (b) the higher the Mw, the higher the wettability alteration at 1,960-ppm TDS salinity (Row

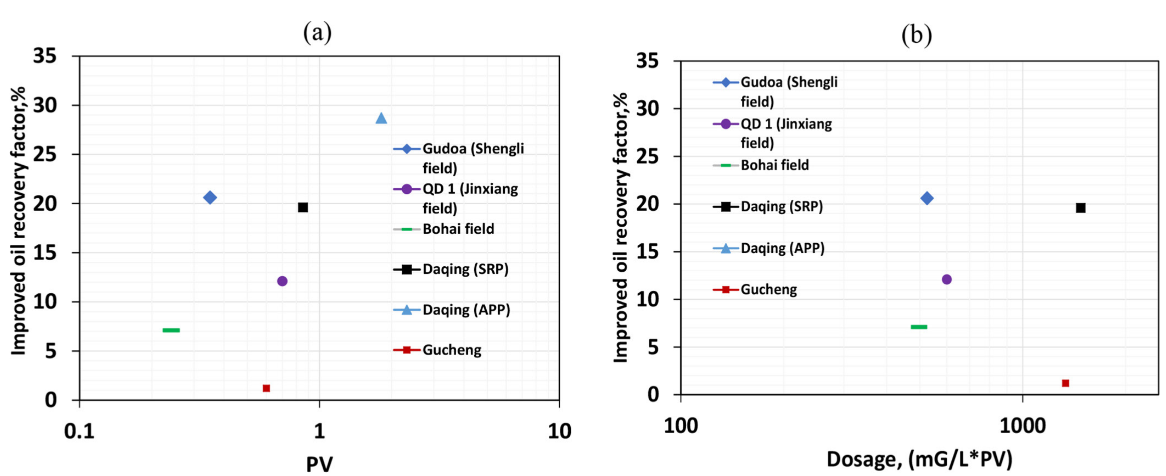

Fig. 9—IORF for Chinse polymer-flood projects as a function of (a) pore volume injections and (b) dosage (mG/L*PV) (compiled by Guo et al. 2021).

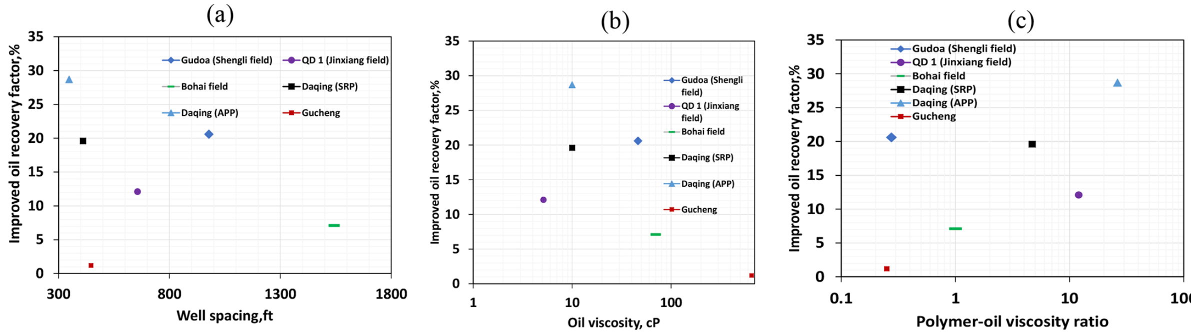

Fig. 10—IORF as a function of (a) well spacing, (b) oil viscosity, and (c) polymer/oil viscosity ratio, for Chinese polymer-flood projects (from Guo et al. 2021).

16 of Table S-2); and (c) the lower the salinity, the higher the wettability alteration (Row 16 of Table S-2). We also caution that Li et al. and Souayeh's work was done with oil-wet rocks. However, Amiri's work conveys that polymer concentration and low salinity can influence wettability alteration in both oil-wet and water-wet rocks (Row 21 of Table S-2). The polymer solutions used by Li et al. (2020), Souayeh et al. (2022), and AlSofi et al. (2019b) involved SNF's AN series of polymers (which contain ATBS). Row 20 of Table S-2 suggests that HPAM alters the wettability more than ATBS-based polymers. HPAM was used at Daqing. Please refer to Azad and Seright (2024) for a more detailed discussion. Nevertheless, we recommend generating CDCs at the Daqing conditions along with the wettability measurements.

Project 6: Tambaredjo Vertical Well Polymer-Flood Project. This field is located in Suriname and is operated by Staatsolie. Wells are vertical.

Methodology 1. Rock and fluid properties are extracted from Manichand et al. (2013). Notably, 1,000–1,300-ppm 3630 HPAM in 500-ppm brine is injected in the project. The permeability of the reservoir is 4–12 darcies. The shear thickening onset rate is around 1 ft/D for a permeability of 4 darcies (Table S-1). An average thickness of 20 ft is considered in this analysis. Two interwell distances of 275 ft and 408 ft represent the shortest and average distances, respectively. Two injection rates representing the high and average values are used. They are 335 STB/D and 175 STB/D. With these values, sensitivity studies examined the effect of radial distance from the wellbore on Darcy velocity **(Fig. 11a)**. The percentage of the reservoir experiencing a velocity more than the onset velocity for each of the cases is calculated and plotted in **Fig. 11b**.

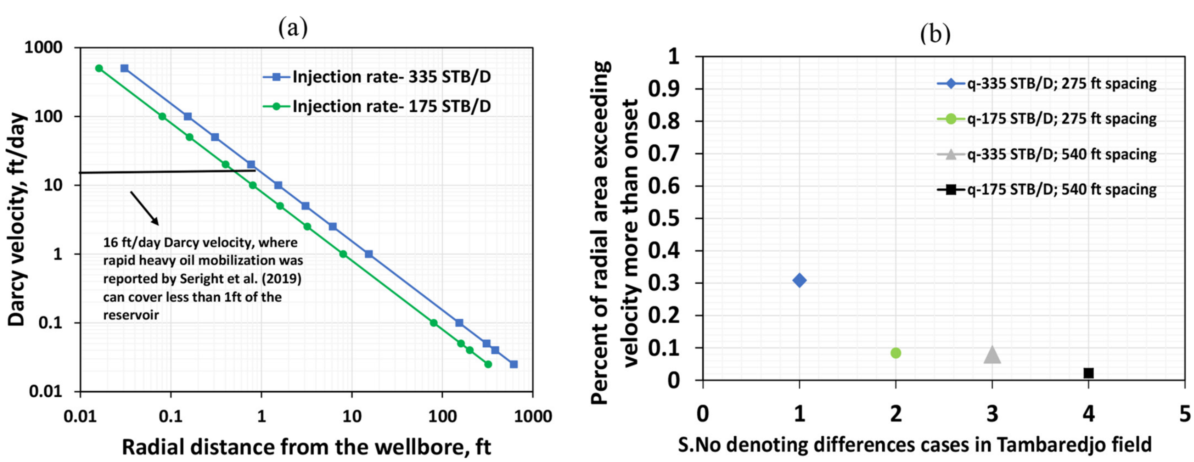

Fig. 11—(a) Effect of radial distance from the wellbore on Darcy velocity for the Tambaredjo Suriname project. (b) Percent of the radial area of the Tambaredjo reservoir exceeding the onset velocity for shear thickening (S.no means serial number).

Fig. 11a shows that 1 ft/D flux can extend only 15.3 ft and 8 ft in high- and low-rate injection cases, respectively. The reservoir area enclosed by these distances does not exceed 0.1–0.3% in any of the cases **(Fig. 11b)**—signifying that the shear thickening viscoelastic effects are too low for any S_{or} reduction.

Methodology 2. The maximum possible Darcy velocity for the lowest porosity, high injection rate, and short well spacing is 0.06 ft/D (Table S-1). Oil viscosity is around 1,728 cp. Seright et al. (2018) reported that, at 16 ft/D Darcy velocity, significant S_{or} reduction occurs with 1,250 cp heavy oil in high-permeable media (Row 4 in Table S-2). The impossibility of S_{or} reduction can be understood by noting that 16 ft/D needed for rapid mobilization of this heavy oil can be obtained within 0.76 ft of the wellbore **(Fig. 11a)**.

The low salinity of 500-ppm TDS, coupled with high HPAM Mw of 18–20 MDa, may favor wettability alteration (Souayeh et al. 2022). However, as discussed before in the case of the Milne Point project, wettability alteration and low-flux recovery with heavy oil might be difficult (Fischer et al. 2008; Meng et al. 2017). The incremental recovery factor is 11.3% OOIP (Delamaide et al. 2016a, 2016b)), which is considerably lower than four of the Chinese light oil polymer-flood projects **(Fig. 9)**. Interestingly, the Bohai oil and Gucheng field [characterized by higher oil viscosity of 21–453 cp and 400–1,800 cp (Table S-1)] yielded lower recovery factors, signifying the relative difficulty associated with heavy oil recovery, including its mobilization as reported by Vermolen et al. (2014). Nevertheless, as with the other cases, a detailed investigation of low-flux recovery and development of the CDC is suggested for Tambaredjo conditions.

Project 7: Marmul Vertical Well Case. This field situated in Oman is operated by PDO. Vertical wells were used.

Methodology 1. Rock and fluid properties are extracted from Koning et al. (1988). The injected polymer system is 1,000-ppm 3630 HPAM in 600-ppm TDS water (Table S-1). The permeability of the reservoir is ~15 darcies. The shear thickening onset rate is around 2 ft/D. The average thickness is 52 ft. Two interwell distances of 200 ft and 600 ft, representing the pilot scale and field scale, are included. The injection rate is about 3,145 STB/D. The average Darcy velocity is from 0.03 ft/D to 0.08 ft/D, depending on well spacing. With these inputs, **Fig. 12a** shows sensitivity studies of the effect of radial distance from the wellbore on Darcy velocity.

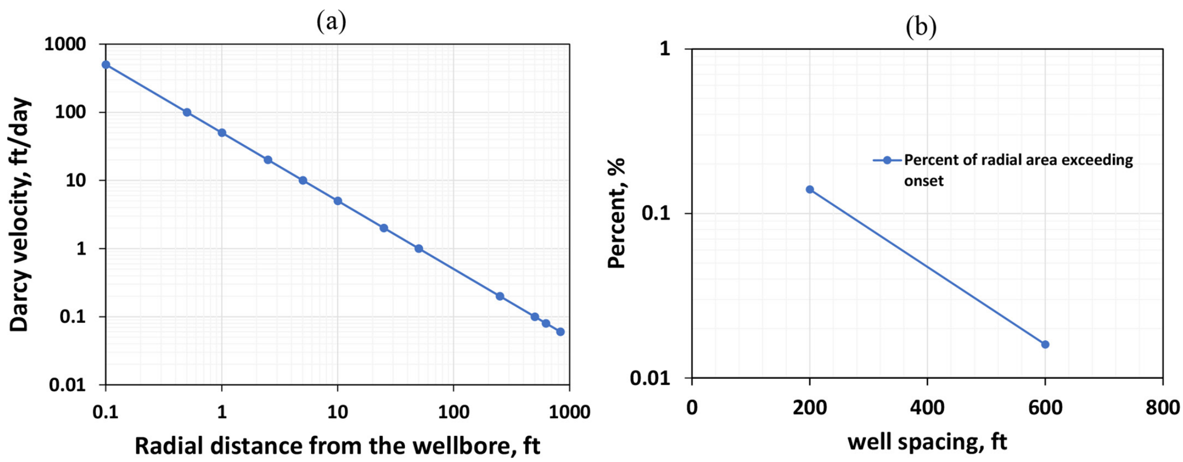

Fig. 12—(a) Effect of radial distance from the wellbore on Darcy velocity for the Marmul project. (b) Percent of the reservoir exceeding the onset velocity in the Marmul project.

The percentage of the reservoir experiencing a velocity more than the onset velocity for the pilot and field scales was calculated and is shown in **Fig. 12b**. These values are 0.14% and 0.02%, respectively. From **Fig. 12a**, a 2 ft/D flux can only reach 25 ft from the well. Therefore, the velocity is too low for any shear-thickening viscoelastic effects. High permeability delays the viscoelastic onset rate (Heemskerk et al. 1984).

Methodology 2. Oil viscosity in this field is about 80 cp. The maximum possible Darcy velocity is 0.08 ft/D (Table S-1) and the polymer solutions are injected at 600-ppm TDS salinity. At these low-salinity injection conditions with an oil viscosity of 80 cp, we can compare expectations with the data of Qi et al. (2017)—which were conducted with 120-cp oil at 0.14 ft/D at low-salinity conditions (Row 1 in Table S-2). Although a small amount of oil was recovered by Qi et al., wettability alteration may be primarily responsible for any incremental oil recovered (AlSofi et al. 2017; Souayeh et al. 2022; Amiri et al. 2022). The rock permeability in the work of Qi et al. (2017) was ~2,200 md, whereas for Marmul, the rock was stated to be about 15,000 md (Table S-1). Lower permeability could lead to greater trapping of oil. However, oil trapping becomes less likely in Marmul's very permeable rock.

Some studies suggest that if the macroscopic viscosity is not dominant, residual oil recovery can happen by virtue of normal stress/extensional stress at the pore scale (Afsharpour et al. 2012; Clarke et al. 2016; Azad and Trivedi 2020a, 2021). On the other hand, higher permeability could activate cocurrent capillary imbibition (Schechter et al. 1991; Azad 2021, his Figs. 12 and 13), and it may favor the possibility of low-pressure gradient recovery in a permeable formation. This can be understood from Row 12 of Table S-2, where Jin et al. reported S_{or} reductions of 0.098 and 0.09 saturation units in 4,400-md cores with pressure gradients of 6.75 psi/ft and 3.5 psi/ft, respectively, during the injection of 1,000-ppm, 18–20 MDa Flopaam 3630 HPAM.

Nevertheless, an extremely low average velocity, coupled with a larger well spacing of 600 ft, suggests that S_{or} reduction by shear thickening is unlikely at Marmul. Large well spacing may increase the risk of retrapping because both the pressure gradient and the localized viscoelastic effects may decrease as flood front propagates to the farthest portion where it experiences low flux (Azad and Trivedi 2021, their Fig. 8). Studies of the effect of permeability on retrapping and mobilizing of residual oil during polymer flooding could be beneficial. We suggest performing core experiments under representative Marmul conditions with varying permeability to generate CDCs.

Project 8: Diadema Vertical Well Case. The Diadema oil field is located in the San Jorge Gulf Basin, Argentina. The field is operated by CAPSA.

Methodology 1. Rock and fluid properties are extracted from Buciak et al. (2015). The injection water salinity is 16,000-ppm TDS brine with 1,000-ppm hardness. The predicted shear thickening onset is 2.5 ft/D (Table S-1). The permeability of the reservoir is 500 md. The average thickness is around 26 ft, while the lower and upper values are 13 ft and 39 ft. The interwell distances are about 820 ft. The injection rate is 1,256 STB/D. The calculated average Darcy velocity is in the range of 0.05 ft/D. Sensitivity studies of the effect of radial distance from the wellbore on Darcy velocity were performed at three thicknesses **(Fig. 13)**.

Fig. 13b shows that 2.5-ft/D flux may extend to 11.7 ft, 18 ft, and 35 ft, respectively, from the well for the low- to high-thickness cases. These values are very small when compared to interwell distances. The percentages of the reservoir radial area experiencing a velocity greater than the onset velocity for the three cases of thickness calculated are 0.18%, 0.02%, and 0.04 %, respectively **(Fig. 13c)**. These values indicate that, for a well spacing of 820 ft, macroscopic viscoelastic force by HPAM solutions will not manifest to any significant distance.

Methodology 2. The average Darcy velocity in the reservoir is 0.05 ft/D (Table S-1). The oil viscosity is 100 cp; the injection water salinity is 16,000-ppm TDS, and the HPAM polymer concentration is 1,500–3,000 ppm (Table S-1). Azad and Seright (2024) ruled out the possibilities of S_{or} reduction. Consider an experiment by Qi et al. (2017) using 500–2,100-ppm Flopaam 3630 HPAM with

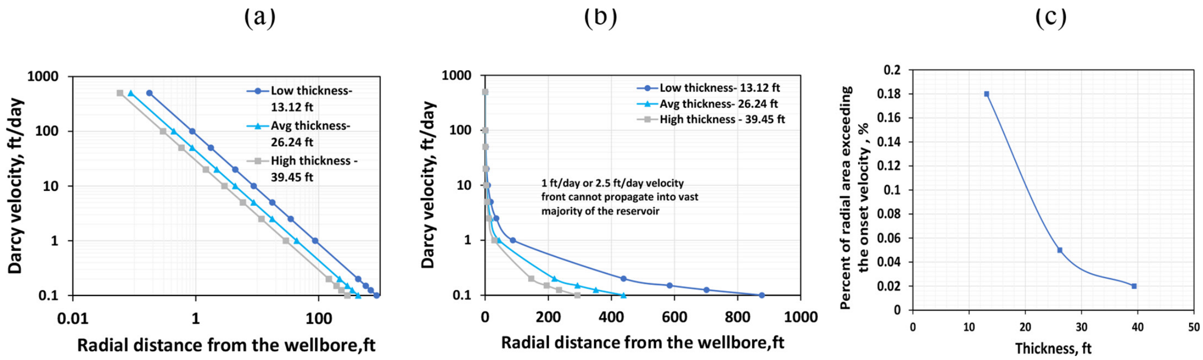

Fig. 13—Effect of radial distance from the wellbore on Darcy velocity for Diadema vertical well project in (a) log-log scale and (b) semilog scale. (c) Percent of the reservoir exceeding the onset velocity at the Diademma project for different thicknesses.

400–11,000-ppm TDS salinity in a 2,200–2,400-md core saturated with 120 cp oil. Table S-1 of Qi et al. (2017) and Row 1 of Table S-2 in the Supplementary Material of our paper show that a slight reduction in S_{or} was evident with low-salinity polymer injection but not with high-salinity polymer injection when the Darcy velocity was less than or equal to 0.2 ft/D. This observation suggests wettability alteration under low-salinity polymer conditions (AlSofi et al. 2017; Li et al. 2020). Although Souayeh et al. (2021) reported a reduction in contact angle during both low- and high-salinity polymer injection (1,960-ppm TDS and 19,600-ppm TDS, respectively) (Row 16 of Table S-2), the oil used in their experiment has a viscosity of only 3.6 cp. In the experiment of Qi et al., the oil viscosity is 120 cp and suggests that high salinity in the polymer may impair wettability alteration if the oil is heavy. The expected incremental recovery factor in the Diademma project at high-salinity injection conditions is only 6–8% (Buciak et al. 2015). However, more investigation is needed to confirm this suggestion. The Diadema polymer injection project seems unlikely to reap S_{or} reduction benefits due to polymer's viscoelasticity.

Project 9: Mangala Vertical Well Project. The Mangala field is located in the Barmer basin in India. The polymer-flood project was initiated in 2014. Cairn operates the polymer-flood project. Wells are vertical.

Methodology 1. Rock and fluid properties are extracted from Kumar et al. (2012) and Shankar et al. (2022). The injection water salinity is 5,400-ppm TDS brine, and the polymer is 2,000–3,000-ppm Flopaam 3630 HPAM. The predicted shear thickening onset is ~1 ft/D (Table S-1). Note that ~1 ft/D is the average value calculated for 3,000-ppm TDS and 1,000-ppm concentration in ~5,000 md rocks. An increased salinity between 3,000-ppm TDS and 5,000-ppm TDS or an increased concentration between 1,000 ppm and 2,000 ppm will not change the onset rate (Seright et al. 2023). The permeability of the reservoir is 500 md. The low and high values of thickness are 51 ft and 112 ft, respectively. The interwell distances are 230 ft. The injection rate is 750 STB/D. The average Darcy velocity in the reservoir is from 0.03 ft/D to 0.06 ft/D. This average velocity is almost two orders of magnitude lower than the onset velocity for shear thickening. Therefore, the possibility of shear thickening viscoelastic force inducing S_{or} reduction is negligible in this reservoir. Sensitivity studies of the effect of radial distance from the wellbore on Darcy velocity at two thicknesses are shown in **Figs. 14a and 14b**.

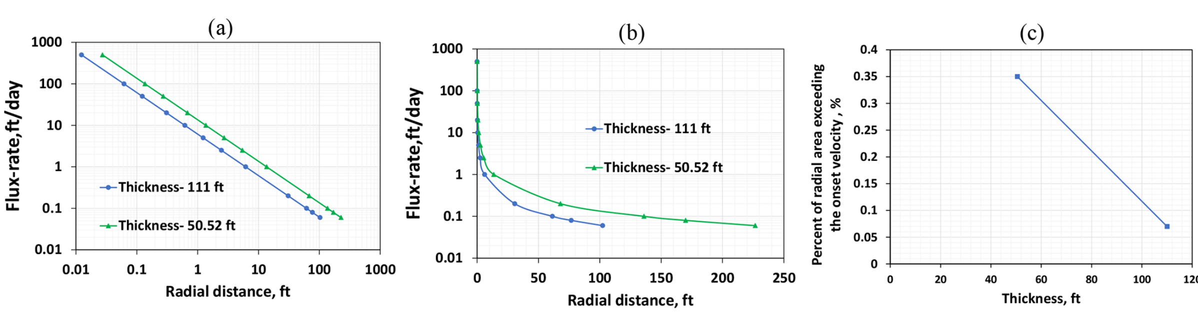

Fig. 14—Effect of distance from the wellbore on Darcy velocity for Mangala vertical well project in (a) log-log scale and (b) semilog scale. (c) Percent of reservoir exceeding the onset velocity at the Mangala project for two different thicknesses.

Notably, 1-ft/D velocity extends radially to only 6.4 ft and 13.6 ft for low and high thicknesses of 51 ft and 111 ft, respectively. The percentage of the reservoir area experiencing a velocity greater than the onset velocity for two thicknesses is shown in **Fig. 14c**. These values are 0.35% and 0.07% for 51-ft and 111-ft thicknesses, respectively. Fractures of 30–50 ft were created as per falloff tests (Shankar et al. 2022). As with other vertical-well cases, if these fractures are accounted for, then the velocity will be too low so that benefits from the shear thickening effect will not occur.

Methodology 2. The average velocity is between 0.03 ft/D and 0.06 ft/D. The oil viscosity is 13 cp, the injection water salinity is about 5,400-ppm TDS, and the Flopaam 3630 HPAM polymer concentration is 2,000–3,000 ppm. To assess whether the Mangala polymer flood can benefit from polymer viscoelasticity, two coreflood experiments conducted by Qi et al. (2017) and Vermolen et al. (2014) are considered. Qi et al. (2017) used 0.2 ft/D with 600-ppm 3630 HPAM (in a 2,200-md core saturated with 120-cp oil) at a salinity of 400-ppm $NaHCO_3$. A slight reduction in S_{or} was observed by Qi et al., which is not significant (Row 1 in Table S-2). In the work of Qi et al., the oil viscosity was 120 cp, whereas in the Mangala project, the oil viscosity was 13 cp. As per Abrams (1975) theory, the higher the oil viscosity, the lower the residual oil recovery. Will this affect the Mangala project, which has a viscosity almost one order of magnitude lower than the work of Qi et al. (2017)? Consider Vermolen et al. (2014) experiments performed using 200 cp Flopaam 3530 HPAM in a 850-md core saturated with 9 cp light oil. An S_{or} reduction was observed in Vermolen's experiments. However, Vermolen's experiments were performed at the Darcy velocity of 0.22 ft/D, which is much higher than the average Darcy velocity of 0.02–0.06 ft/D under Mangala conditions. Moreover, in the Mangala project, 20-cp HPAM solutions were injected, in contrast to 200-cp injection solutions in Vermolen's experiments. These points indicate that S_{or} reduction is not likely due to the shear thickening viscoelastic forces alone in the Mangala field.

Fig. 8 of Li et al. (2020) suggests that, during spontaneous imbibition experiments using sulfonated polymer, the polymer can recover 19-cp oil (post-brine) from oil-wet cores (Row 15 of Table S-2). This raises a question: Does the rock nature and polymer nature affect wettability alteration during HPAM propagation in the sandstone Mangala reservoir (saturated with oil of similar viscosity)? Row 16 suggests that wettability could be altered to a larger degree with HPAM than with the AN 125 polymer. Row 21 of Table S-2 suggests that wettability alteration with HPAM could occur in both oil-wet and water-wet rocks. Nevertheless, we suggest performing wettability alteration experiments with candidate oil and rock and also developing a CDC by coreflooding at the candidate conditions.

Role of Shear Thickening and Other Effects on S_{or} Reduction. The average velocity computed (assuming there are no fractures) in most of the polymer-flood projects is much lower than the average velocity required for the polymer solutions to exhibit shear thickening viscoelastic effects **(Fig. 15)**. One may wonder how the presence of the oil in the field influences the shear thickening onset velocity and whether that would influence our interpretation. Fig. 9 of Seright et al. (2023) reports that the presence of oil does not change the onset rate significantly, other than the natural effect of reduced permeability associated with the oil saturation. On the other hand, it moderates the degree of shear thickening. Moreover, **Fig. 15** reveals that the computed average field velocity for all the field cases is much lower than the shear thickening onset velocity by a significant margin. Note that the average velocity for Pelican Lake is computed by including the shortest well spacing of 30 m as well, and if they are excluded, the average velocity would become even lower. Thus, even considering the shift in the shear thickening onset velocity (due to reduced permeability associated with the presence of oil), it does not affect our conclusion that the shear thickening effects are not significant in the majority of the polymer-flooded reservoirs. This is despite not accounting for the fracture, whose presence would reduce the velocity even lower.

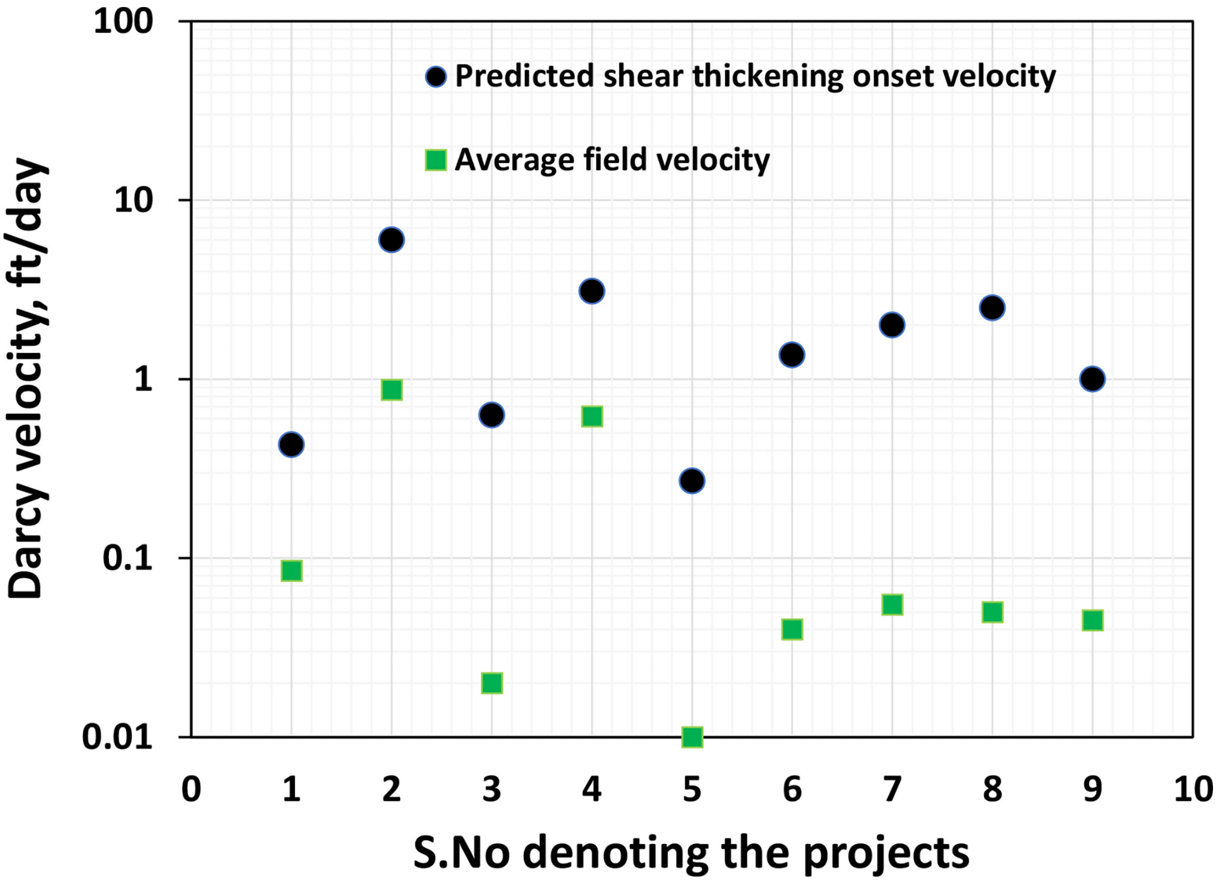

Fig. 15—Comparison between the prevailing average Darcy velocity and the predicted shear thickening onset velocity for the compiled projects. 1—Milne Point, USA; 2—Pelican Lake, Canada; 3—East Messoyakhskoe, Russia; 4—Matzen, Austria; 5—Daqing SRP, China; 6—Tambaredjo, Suriname; 7—Diademma, Argentina; 8—Marmul, Oman; and 9—Mangala, India.

Therefore, shear thickening viscoelastic aspects are not sufficiently significant to induce S_{or} reduction in any of the conducted polymer flood projects.

Several laboratory studies indicated that the viscoelastic polymer solutions can influence S_{or} reduction at a relatively low flux of ~0.2 ft/D, where shear thickening effects are not significant (Ehrenfred 2013; Clarke et al. 2016; Qi et al. 2017; Erincik et al. 2018; Barri et al. 2023). Azad and Trivedi (2019a, 2020b, 2021) reported that the localized viscoelastic effects could play a role in S_{or} reduction at the pore scale and tied the extensional effects as the reasons for the observed higher S_{or} reduction at the flux rate less than the shear thickening onset fluxes and/or relatively lesser fluxes. Does that mean at the local scale, the velocity could be locally very high, as reported in Berg and van Wunnik (2017)? And therefore, can the polymer-flood projects experience higher localized velocity at the pore scale in the significant portion of the field projects (and therefore reap the benefits of S_{or} reduction)?

To answer this, it is important to understand and differentiate between the average velocity and the localized strain rate. The average velocity is simply the macroscopic velocity with which the fluid front is propagating. It is influenced by reservoir thickness, radial distance in the vertical well projects (Eq. S-1), and the horizontal well length (Eq. S-2). If the velocity could become higher locally due to the pore structure constriction regardless of the average imposed velocity and flood front distance, then S_{or} reduction in the porous media must be the same, regardless of the average imposed velocity. This is not the case—see Qi et al. 2017, where high-salinity polymer injection at the Darcy velocity of 0.2 ft/D did not result in any S_{or} reduction, whereas the high-salinity polymer injection at the Darcy velocities of 0.96 ft/D and 7.6 ft/D resulted in an S_{or} reduction of 0.05–0.1, respectively, under similar petrophysical conditions (Row 1 in Table S-2). Thus, the size effect (due to pore structure) and the time effect (due to higher velocity) play a combined role in the manifestation of viscoelastic effects (Azad 2023). The localized strain rate is the rate at which the polymer chains become stretched as it advances from the pore body to the pore throat. It is controlled by the average velocity itself along with the aspect ratio between the pore body and pore throat (Eq. 7 in Azad and Trivedi 2021; Flew and Sellin 1993). For the same aspect ratio, the lower the average velocity, the lower the strain rate at the pore scale and vice versa (Azad and Trivedi 2021, their Fig. 8). Now the question arises: Could the localized viscoelastic effects contribute to S_{or} reduction at all?

Row 1 of Table S-2 not only conveys that Qi et al. (2017) reported the inability of high-salinity polymer solutions to reduce S_{or} at low flux but also conveys that, during low-salinity polymer injection in similar petrophysical conditions, a slight but consistent reduction in S_{or} is observed at low flux, indicating that high fluxes are important. Another important factor to consider is that the oil used by Qi et al. (2017) is 120 cp, which is a bit heavy. Row 2 of Table S-2 indicates that Vermolen et al. (2014) revealed that while 300-cp heavy oil cannot be mobilized, 9-cp oil can be mobilized by viscoelastic polymer injection at similar petrophysical conditions. Furthermore, Row 24 of Table S-2 reveals that the lighter the oil, the higher the spontaneous imbibition recovery. A considerable wettability alteration by polymer solutions has been reported in Li et al. (2020), AlSofi et al. (2019a, 2019b), Souayeh et al. (2022), Amiri et al. (2022), and Al-Busaidi et al. (2023) in both carbonates and sandstone rocks saturated with relatively light oil with low viscosity (Rows 14–16, 20, and 21 of Table S-2). This conveys that, besides the localized extensional viscoelastic effect, the low-salinity injection conditions for the wettability alteration and the light oil for easing the wettability alteration are essential for S_{or} reduction in the absence of high flux (shear thickening) conditions. If this is the case, oil reservoirs with relatively low oil viscosity appear to be benefitted with S_{or} reduction, which seems to be the case with Daqing projects (as discussed before). However, we cannot say with certainty that S_{or} reduction is occurring, because several factors such as pore size distribution, wettability, mineralogy, retention, possible retrapping, and a sustained extensional effect could play a role, and therefore, a case-by-case development of CDC along with wettability alteration potential in the relatively lengthier cores in the field condition of interest is necessary.

Conclusions

In this section, we summarize the list of conditions/parameters for each field case that preclude or favor those fields to reap S_{or} reduction due to shear thickening viscoelastic effects and/or mechanisms such as wettability alteration. None of the fields are experiencing an average velocity that is even close to the onset velocity needed by the EOR polymer solutions creating viscoelasticity-induced shear thickening effects. This is despite us not accounting for the effect of fractures (which would reduce fluid velocities).

Horizontal Well Polymer-Flood Projects. The general observation from the horizontal well projects is that for various combinations of thickness, well spacings, and horizontal well length, the average velocity is low—in the range of 0.01–0.2 ft/D, whereas the shear thickening onset values are greater than 1 ft/D.

a. For Milne Point, Alaska, USA, the long horizontal wells and large well spacing result in Darcy velocities from 0.05 ft/D to 0.12 ft/D, which is substantially lower than the onset velocity for shear thickening (~0.43 ft/D). Based on 0.05–0.12 darcy velocity and pressure gradient of 0.85 psi/ft along with viscous Milne Point oil (~200 cp), laboratory coreflood suggests no significant S_{or} reduction.
b. For the case of Pelican Lake, Canada, the highest average velocity is 0.26 ft/D for the lowest thickness of 3.28 ft, the commonly used well spacing of 656 ft, the highest injection rate of 755 B/D, and the shortest well length of 4,922 ft. This is much lower than 4 ft/D—the onset velocity for the shear thickening in high-permeability sand. Laboratory studies suggest that for these prevailing low velocities, the high oil viscosity (above 800 cp) provides no reason to suspect S_{or} reduction during the field polymer flood.
c. For short well spacings of 164 ft and 98 ft under Pelican Lake conditions, the average Darcy velocities are 1.04 ft/D and 1.74 ft/D, respectively. Even then, high oil viscosity does not appear to favor S_{or} reduction, at least in the tertiary mode.
d. A secondary mode of polymer flooding provides positive effects on oil recovery in Pelican Lake, and the reason could be a snap-off reduction. However, the Pelican Lake reservoir is characterized by a wide range of permeability, so more research is needed to account for the effects of different permeabilities.
e. For the East Messoyakhskoe field, long horizontal wells, large well spacing, and large thickness all result in low average Darcy velocities between 0.01 ft/D and 0.03 ft/D, which are much lower than the average shear thickening onset velocity of 0.63 ft/D. The high oil viscosity may limit wettability alteration. No information about the water salinity is available to interpret other mechanisms.
f. Although the Matzen field (Austria) has the shortest well length (1,210 ft), an average velocity of 1 ft/D (a comparable value to the onset rate for shear thickening) would occur only in the thinnest (10 ft) and least permeable (100 md) portion of the reservoir. In other parts of the reservoir, the average velocity is lower than 1 ft/D, and the onset velocity for shear thickening is greater than 1 ft/D, thereby diminishing the likelihood of shear thickening effects. Laboratory studies suggest that, at velocities less than 1 ft/D, no significant S_{or} reduction is observed, especially for high-salinity polymer injection. It might be interesting to determine how the wetting nature of the Matzen reservoir, coupled with low oil viscosity, would benefit wettability alteration as a recovery mechanism.

Vertical Well Polymer-Flood Projects. A common conclusion for all the vertical well projects is that less than 2–3% of any given reservoir experiences a velocity above the onset velocity for shear thickening.

a. Among the Chinese cases, Daqing resulted in the highest recovery factor. However, a higher pore volume was injected for Daqing cases. Guo et al. (2021) reported that a large reduction of water cut, high polymer/oil viscosity ratio, low oil viscosity, concentrated, low-salinity polymer systems, and smaller well spacing are associated with Daqing, These conditions could induce wettability alteration to provide higher recovery factors.
b. Lessons learned from comparing the QD1, Gucheng, and Daqing SRP projects are that not only do short well spacing, high polymer/oil viscosity ratio, or lower oil viscosity lead to higher recovery, but that a combination of all these favors higher recovery.
c. In the case of the Tambaredjo field, average Darcy velocities were only 0.02–0.06 ft/D with average interwell distances of 275 ft and 408 ft, respectively. These velocities are much lower than the onset velocity for shear thickening (~1 ft/D). Laboratory comparisons reveal that a high oil viscosity of 1,7 28 cp along with lower velocities does not favor S_{or} reduction.

d. For Oman's Marmul project, large well spacing not only keeps the average velocity much lower than the shear thickening onset but also increases the possibility of retrapping of mobilized oil.
e. A larger well spacing of 820 ft at Diadema leads to the average Darcy velocity of 0.05 ft/D, which is much lower than the shear thickening onset velocity of 2.5 ft/D. At 0.2 ft/D, a cross-comparison with various laboratory experiments appears to indicate that the high salinity of polymer solutions, coupled with high oil viscosity, hinders the possibility of S_{or} reduction.
f. For the relatively small interwell distance of 223 ft but relatively high thickness of 51 ft and 112 ft in the Mangala field, the calculated Darcy velocities are 0.03 ft/D and 0.06 ft/D, respectively. These velocities are almost two orders of magnitude lower than the onset velocity of ~1 ft/D (for shear thickening). At these low velocities, a cross-comparison between the laboratory studies reveals that low velocity impairs the possibility of S_{or} reduction. However, the light 13-cp oil associated with Mangala conditions provides hope for a possible wettability alteration.

Suggestions for Future Work.
1. If a reservoir is characterized by substantial permeability variations, it may be prudent to evaluate the S_{or} reduction for different permeabilities instead of only the average permeability.
2. Both imbibition and forced-flow experiments are important if we are to ascertain the polymer system recovery potential at different salinities.
3. We suggest performing case-by-case investigations to ascertain polymer flood effects on S_{or} reduction and attainment of a critical capillary number.
4. We also suggest that the polymer flooders must be prepared to operate the laboratory-scale flooding at a low flux rate in the vicinity of 0.02 ft/D, which may take several days or weeks. Using a Darcy velocity of 0.2 ft/D (roughly equal to the interstitial velocity of 1 ft/D) for a faster completion of flooding may produce overly optimistic results. Viscoelasticity is a time-dependent phenomenon that gets amplified in coreflood at relatively higher fluxes.
5. We also suggest performing laboratory-scale polymer flood at a low-pressure gradient because even low flux may lead to a higher pressure drop if the permeability is low. Also, the pressure-driven flow may be dominant in the deeper portions of the reservoir (rather than the velocity-driven flow).
6. We also recommend performing experiments using different core lengths to evaluate the S_{or} reduction potential of viscoelastic polymers to analyze the possible retrapping.
7. Pore size distribution, heterogeneity, and wetting nature could play a crucial role in S_{or} reduction during viscoelastic polymer flooding, and it is recommended to use the cores (especially the carbonate cores) from the representative field and age them to their original wettability while generating CDCs.

Overall Conclusion

Reduction of capillary-trapped residual oil saturation via viscoelastic (shear thickening) forces is unlikely to be significant in any of the field polymer floods examined in this paper. Enhanced recovery by other mechanisms (e.g., wettability alteration) is possible in some of the applications.

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