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Abstract

Effective oil displacement from a reservoir requires adequate and properly directed pressure gradients in areas of high oil saturation. If the polymer bank is too large or too viscous during a polymer flood, the pressure drop from the injection well to the polymer front may act as a pressure barrier by usurping most of the downstream driving force for oil displacement. Polymer injection pressures must be limited. The maximum allowable injection pressure is commonly constrained by caprock integrity, injection equipment, and/or regulations, even though fractures can be beneficial to polymer injectivity (and even sweep efficiency in some cases). This paper examines when the pressure-barrier concept limits the size and viscosity of the polymer bank during a polymer flood.

Both analytical and numerical methods are used to address this issue. We examine the relevance of the pressure barrier concept for a wide variety of circumstances, including oil viscosities ranging from 10-cp (like at Daqing, China) to 1650-cp (like at Pelican Lake, Alberta), vertical wells (like at Tambaredjo, Suriname) versus horizontal wells (like at Milne Point, Alaska), single versus multiple layered reservoirs, permeability contrast, and with versus with crossflow between layers. We also examine the relation between the pressure-barrier concept and fractures and fracture extension during polymer injection.

We demonstrate that in reservoirs with single layers, the pressure-barrier concept only limits the optimum viscosity of the injected polymer if the mobility of the polymer bank is less than the mobility of the displaced oil bank. The same is true for multi-zoned reservoirs with no crossflow between layers. Thus, for these cases, the optimum polymer viscosity is likely to be dictated by the mobility of the oil bank, unless other factors (like fracture extension) intervene. For multi-zoned reservoirs with free crossflow between layers, the situation is different. A compromise must be reached between injected polymer viscosity and the efficiency of oil recovery. The relevance of our findings is applied to operations for several existing polymer floods. This work is particularly relevant to viscous-oil

reservoirs (like Pelican Lake and others) where polymer viscosities are substantially lower than the oil viscosity

Introduction

Economic oil displacement requires a sufficient pressure gradient or driving force to push the oil to a production well. Many different pressure sources are often available for this function (Figure 1). For example, water from a nearby injection well often provides this driving force. However, if the oil is viscous, fingers can develop that causes the water to bypass the oil. A bottom water drive can also provide pressure support, but water coning (along with viscous fingering) can allow the water to short-circuit to the producer. Solution gas can provide some pressure support, but in viscous oil reservoirs, the oil is often depleted of gas so that little drive pressure remains. A gas cap could provide some drive energy, but like the case with water, the unfavorable mobility ratio commonly leads to viscous fingering, coning, and inefficient oil displacement. Also, during a polymer flood, much of the injected polymer may be wasted by entering the gas cap or aquifer. Compaction has provided a drive energy in rare cases (e.g., Tambaredjo oil field in Suriname, Wang et al. 2017), but is a small effect in most reservoirs. For most polymer floods, the injected polymer bank is intended to provide the drive energy to efficiently displace the oil.

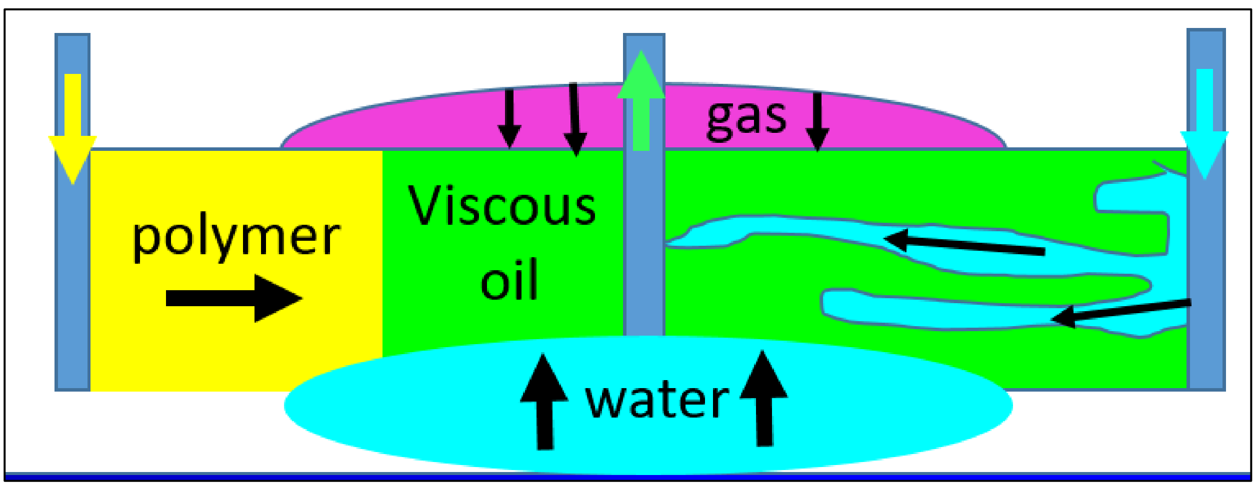

Figure 1—Illustration of sources of pressure to push oil towards a production well

Effective oil displacement from a reservoir requires adequate and properly directed pressure gradients in areas of high oil saturation. If the polymer bank is too large or too viscous during a polymer flood, the pressure drop from the injection well to the polymer front may act as a pressure barrier by usurping most of the downstream driving force for oil displacement. Polymer injection pressures must be limited. The maximum allowable injection pressure is commonly constrained by caprock integrity, injection equipment, and/or regulations, even though fractures can be beneficial to polymer injectivity (and even sweep efficiency in some cases). This paper examines when the pressure-barrier concept limits the size and viscosity of the polymer bank during a polymer flood.

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Simple Analysis

Single Layer.

First, we consider the pressure losses across a polymer bank, assuming a single-layer, incompressible reservoir where the injected polymer provides the only source of drive pressure and oil displacement is linear and piston-like (Figure 2). Assume that a fixed total pressure difference (Δp_t) exists between the injection well and production well. The pressure drop across the polymer bank and oil bank are Δp_p and Δp_o, respectively; the lengths of the polymer and oil banks are L_p and L_o, respectively; and the polymer/oil mobility ratio is M (that is, polymer mobility divided by oil mobility).

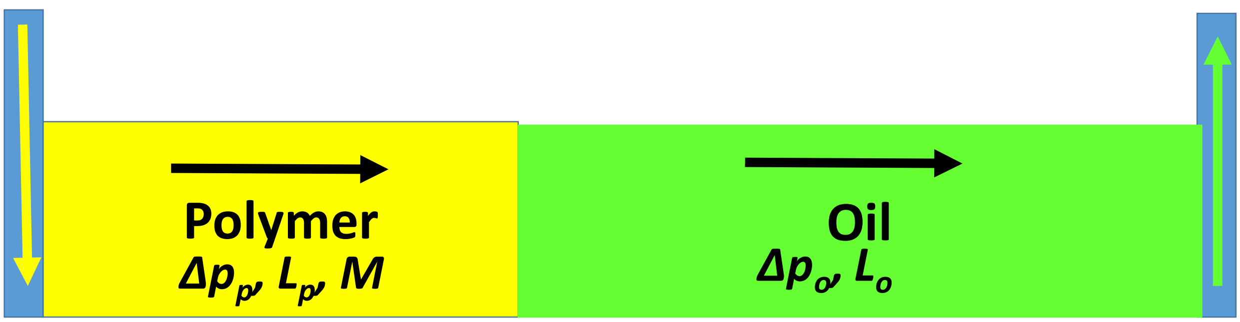

Figure 2—Simple linear, piston-like displacement of oil in a single layer

For this simple case, Darcy's law for flow in series can readily be used to calculate the injection rate relative to the initial rate (q/q_i) as a function of mobility ratio (M) and relative length of the polymer bank [$L_p/(L_p+L_o)$ or L_p/L_t]:

$$q/q_i = M/ [(L_p/L_t) + M(1-L_p/L_t)] \quad (1)$$

Similarly, the pressure gradient in the oil bank relative to the initial pressure gradient within the oil bank $[(\Delta p_p/ L_o)/ (\Delta p_t/ L_t)_i]$ can be calculated using Eq. 2.

$$[(\Delta p_p/ L_o)/ (\Delta p_t/ L_t)_i]= M/ [(L_p/L_t) + M(1-L_p/L_t)] \quad (2)$$

Note that the left side of Eqs. 1 and 2 are the same. Figure 3 plots predictions from these equations, as a function of mobility ratio and fractional polymer distance of penetration (L_p/L_t).

For mobility ratios less than one (i.e., the two red curves in Figure 3), a substantial loss of injectivity occurs—because of the sizeable pressure drop across the polymer bank (i.e., a pressure barrier). As indicated by Eqs. 1 and 2, the pressure gradient across the oil bank follows the same trend as for injectivity. Thus, polymer banks that provide a mobility ratio less than one also create a pressure barrier that significantly decreases the pressure gradient within the oil bank. Thus, for two important reasons (loss of injectivity and pressure gradient in the oil bank), mobility ratios less than one appear undesirable. Of course, sweep efficiency decreases continuously with decreasing mobility ratio (Seright 2017). However, the point raised here is that for mobility ratios less than one, the benefits of sweep improvement may be offset by reduced injectivity and reduced pressure gradient in the oil bank.

The two black curves in Figure 3 show that for mobility ratios greater than one, injectivity and pressure gradient within the oil bank gradually improve (with polymer throughput), but the effects do not become substantial until after 0.5 PV of polymer are injected. Even after 0.5 PV, it may be unrealistic to expect pressure gradients across the oil bank to increase significantly. The reason is that polymer solutions with an unfavorable mobility ratio will viscous-finger through the oil bank. The vertical equilibrium concept (Zapata and Lake 1981, Sorbie and Seright 1992) will force the pressure gradient within the oil bank to match that within the polymer fingers.

The overall message from this analysis is that it is most desirable to maintain a polymer/oil mobility ratio close to one. Mobility ratios less than one will create a pressure barrier that harms both injectivity and pressure gradient within the oil bank. Mobility ratios greater than one may slightly improve injectivity but will not increase pressure gradient within the oil bank.

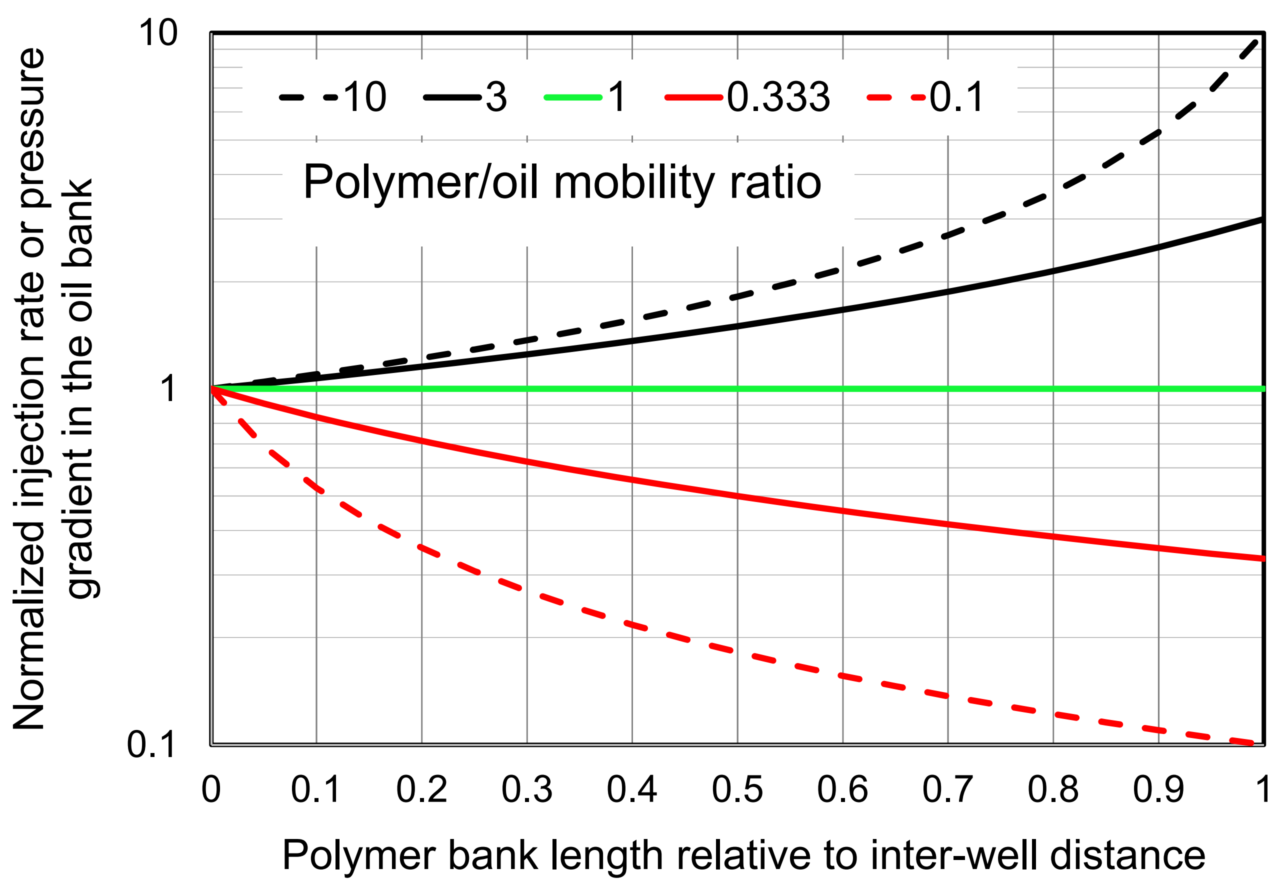

Figure 3—Normalized injection rate or pressure gradient in the oil bank versus polymer/oil mobility ratio and polymer bank length

Multiple Layers with No Crossflow.

If fluids cannot crossflow between adjacent layers, then each layer performs independent of the others. In that case, the conclusions that we reached above for one layer will also apply to multiple layers, so long as no crossflow can occur. Consequently, for a multilayer reservoir with no crossflow, a polymer/oil mobility ratio of one will also be most desirable. This conclusion is consistent with that reached based on fractional flow calculations in Seright 2010.

Multiple Layers with Crossflow.

If fluids can crossflow between adjacent layers of different permeability, fractional flow analysis suggests that the optimum oil displacement will occur when the polymer mobility is lower than one by a factor that is equivalent to the permeability contrast (Seright 2010, 2017). So if one layer has twice the permeability of the other (in a two-layer reservoir with free crossflow), the optimum polymer/oil mobility ratio would be 0.5. If the permeability contrast was 4:1, Seright (2010 2017) predicts that the most efficient displacement would occur with a polymer/oil mobility ratio of 0.25. Will a similar conclusion be appropriate when considering the pressure barrier concept?

With free crossflow, vertical equilibrium should exist—meaning that for any given horizontal position between and injector-producer pair, the horizontal pressure gradient is the same for all layers (Zapata and Lake 1981). Also, if the polymer/oil mobility ratio is less than or equal to the reciprocal of the permeability contrast, the polymer will propagate in the less-permeable layer at the same rate as in the most-permeable layer (Sorbie and Seright 1992; Seright 2017). For that case, the injectivity and pressure-gradient behavior mimics that for the red curves shown in Figure 3. Thus, for the case of free crossflow between layers, lower injectivity and pressure gradient within the oil bank will occur if the polymer/oil mobility ratio is low enough to give the most efficient sweep.

In summary, for the case of free crossflow, a polymer/oil mobility ratio near one will give the optimum injectivity and pressure gradient within the oil bank. This is in spite of the fact that a greater sweep efficiency will result from injecting a more viscous polymer bank. Thus, for all three cases of (1) a single layer, (2) multiple layers with no crossflow, or (3) multiple layers with free crossflow, a polymer/oil mobility ratio of one should provide the optimum injectivity and pressure gradient within the oil bank.

Effect of Vertical Fractures.

For our purposes, fractures in injection wells can be put in one of two basic categories: (1) those oriented perpendicular to the desired direction of flow (between and injector and producer, as in Figure 4a) and (2) those oriented parallel to the desired direction of flow (as in Figure 4b).

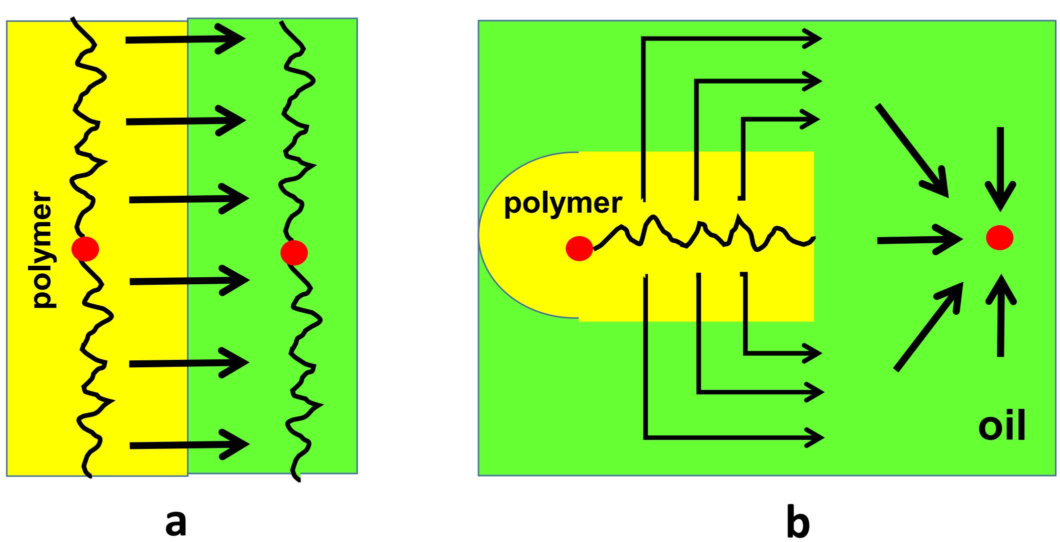

Figure 4—Illustration of effect of fracture orientation

For the situation illustrated in Figure 4a, the case is the same as that shown in Figure 2—i.e., linear flow between two wells. Recall for that case, a polymer/oil mobility ratio of one provides the optimum injectivity and pressure gradient in the oil bank and absence of a pressure barrier associated with the polymer bank.

For the situation illustrated in Figure 4b (with the fracture pointing directly at the production well but leading only part way there), previous work (Crawford and Collins 1954; Dyes et al. 1958; Seright 2017) demonstrated that sweep efficiency will not be compromised so long as the fracture extends less than one-third of the distance between the injector and producer. The streamlines from the fracture toward the production well are not linear. Still, the polymer bank will create a pressure barrier if the polymer/oil mobility ratio is significantly less than one. That pressure barrier would force fracture extension toward the production well with continued polymer injection. In contrast, if the polymer/oil mobility ratio is one or greater, fracture extension is much less likely (although viscous fingering will certainly occur for high mobility ratios). Consequently, a polymer/oil mobility ratio of one appears optimum in this situation as well.

Effect of Horizontal Fractures.

At the Daqing (China) and Tambaredjo (Suriname) fields, induced fractures have been argued to be horizontal (Wang et al. 2011; Manichand et al. 2013). As illustrated in Figure 5, injection could continually extend a horizontal fracture as polymer leaks off along the fracture faces—efficiently sweeping the oil. To explain, high pressure gradients along the polymer bank and high pressures within the fracture are likely to promote fracture extension (just as it does with vertical fractures). Near the fracture tip, polymer can extensively leakoff through the fracture faces into the reservoir—thus pushing oil toward the production well. Far upstream of the fracture tip (toward the injection well), polymer that leaked off into the rock previously probably is stagnant—so that injected polymer exclusively propagates down the open fracture until it reaches the vicinity of the fracture tip. If the distance of polymer leakoff is too great, the polymer bank could act as a pressure barrier when displacing some oils (as suggested by Figures 3 and 4). For that reason, the mechanism shown in Figure 5 will be most effective in thin formations.

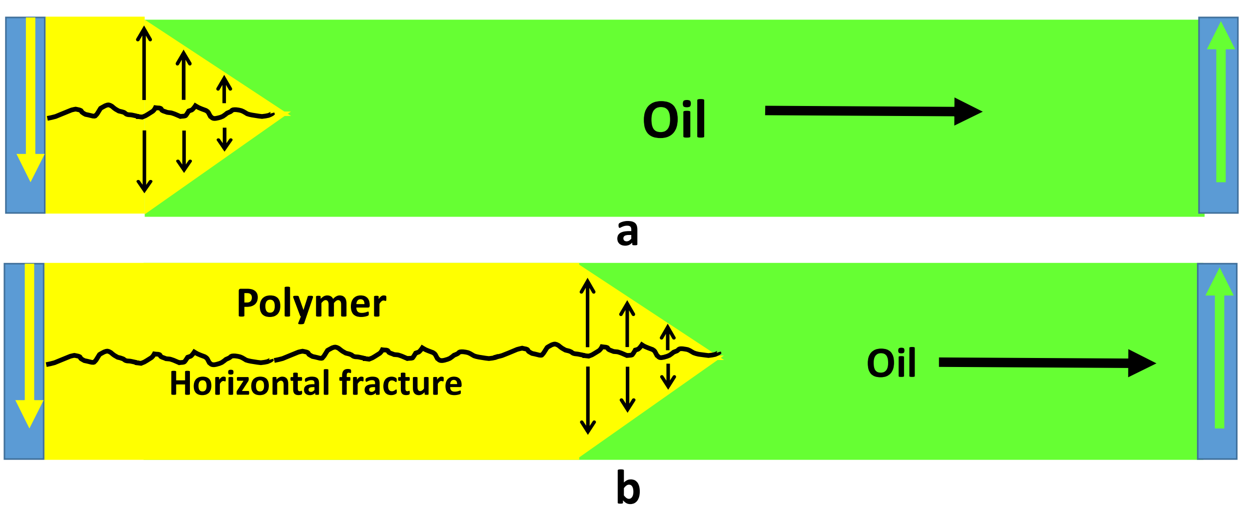

Figure 5—Illustration of propagation of a horizontal fracture during polymer injection

Water Injection before Polymer.

Views differ on the effects of waterflooding before a polymer flood (Kamaraj et al. 2011; Skauge et al. 2014; Delemaide 2016, 2021). Using fractional flow analysis, Kamaraj et al. (2011) noted that waterflooding for any time period (before the start of a polymer flood) had no significant impact on the ultimate volume of oil that could be recovered by a polymer flood.

The fractional flow calculations of Kamaraj et al. (2011) made no allowance for viscous fingering with unfavorable mobility ratios. Skauge et al. (2014) used X-ray tomography to demonstrate the impact of viscous fingers during water flooding and polymer flooding of viscous oils in a 2-D laboratory setting. Viscous fingers from a water flood have been argued as a means to improved injectivity for viscous oil reservoirs and provide the primary pathway for production of displaced viscous oil during a polymer flood. (Skauge et al. 2014).

Observations associated with the Pelican Lake polymer flood (Delamaide 2016, 2021; CNRL 2018) indicate that viscous oil was displaced more efficiently when polymer flooding was implemented directly after primary production than when waterflooding was conducted before the start of the polymer flood. Although statistical analysis of a significant number of polymer flooding patterns supports this conclusion, a physical explanation is not yet evident.

Radial Flow.

Radial flow around unfractured injection wells and production wells has long been recognized as accentuating pressure losses (Seright 1988, Liang et al. 1993) between wells. From a practical viewpoint, it has been effectively argued that all vertical injection wells have open fractures during polymer injection (Seright et al. 2009; van den Hoek, 2009; Ma and McClure 2017, Sagyndikov et al. 2022). In contrast, pressure gradients around production wells are such that no fractures are present or any fractures are closed unless held open by proppant or frac-packs. From this information, we may anticipate that flow is basically linear from the injection well until the polymer approaches a vertical production well. Near the production well, flow will become radial and pressure gradients will become substantial.

Examination of Field Polymer Floods

In this section, we consider several important field applications of polymer flooding, including Pelican Lake (Alberta, Canada), Milne Point (Alaska, USA), Tambaredjo (Suriname), and Daqing (China). Our focus is on describing characteristics of the field that are relevant to the polymer pressure-barrier issue, followed by numerical simulations that examine whether a polymer pressure barrier might be expected under the specific conditions of that field. The simulations were performed for single patterns with one actual injector well and actual production well within existing polymer flood field projects using CMG IMEX. In contrast to the simple models used in the previous section, these simulations used geologic characteristics (including permeability, porosity, layering), PVT and wetting properties (including relative permeabilities), and polymer properties (including rheology in porous media and field-specific retention properties), and average injection and production rates during polymer injection that are relevant to the particular field. The goal was to determine whether the complications associated with the field application might alter the basic conclusions from the previous section. Figure 6 and Table 1 show oil (k_{ro}) and water (k_{rw}) relative permeability curves that were calculated using endpoints and Corey exponents reported in the literature, as well other major parameters used in the simulation (for the area of paired wells) for the four field cases. Details used to establish the simulation models will be introduced in following individual sections.

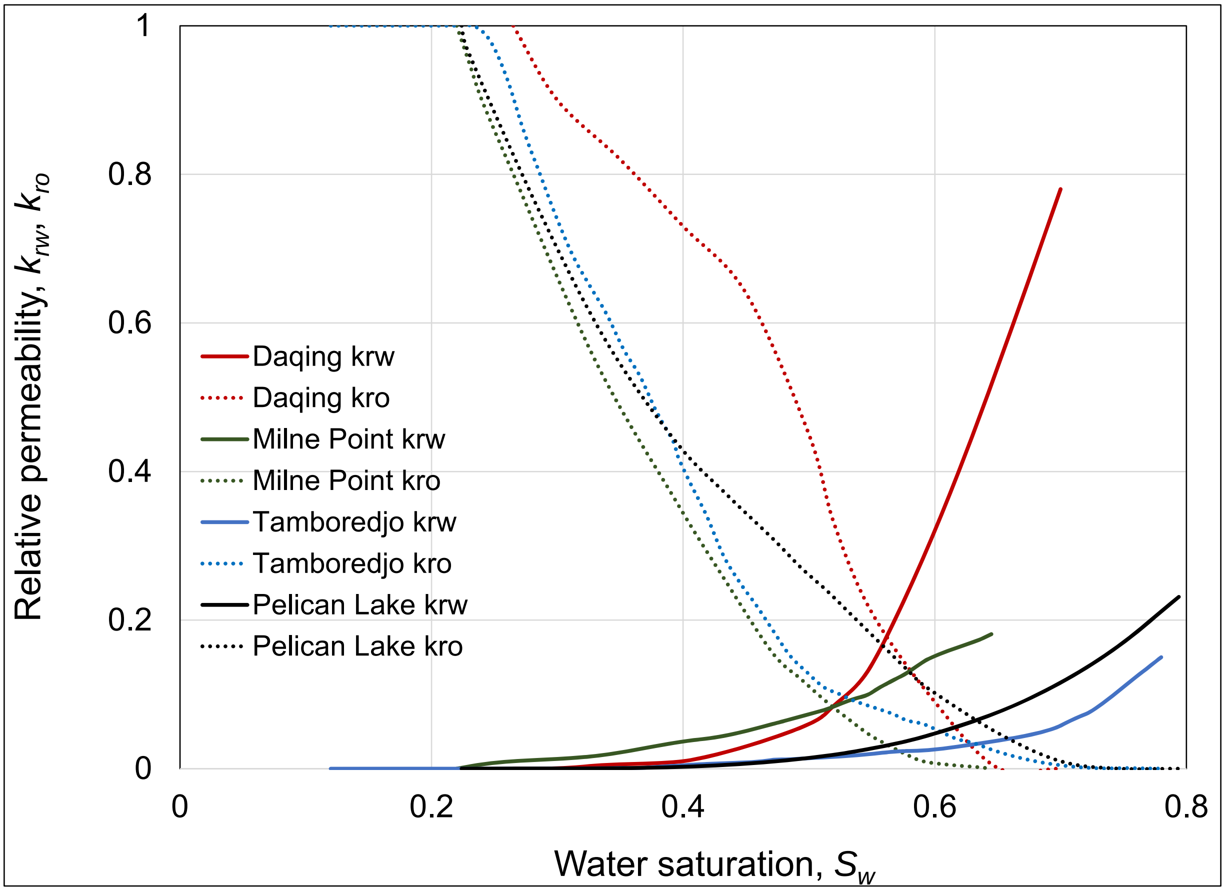

Figure 6—Relative permeability curves used in simulations after smoothing

Table 1—General property of simulation area for the four oil field

Reservoir property	Oil Field			
	Daqing	Milne Point	Tambaredjo	Pelican Lake
Well geometry	Vertical	Horizontal	Vertical	Horizontal
Well spacing, ft	820	1179	443	574
Oil viscosity, cp	10	300	600	1650
Injection layers	4	8	5	2
Ave permeability, md	512	1032	4066	3030
Ave. thickness, ft	8.00	1.70	24.06	4.4
Max. permeability contrast	5.76	1.86	22.32	1.22
Ave. porosity	0.21	0.35	0.19	0.30
Polymer viscosity, cP	45	45	45 ~ 85	22
S_{wi}	0.265	0.220	0.120	0.224
k_{rw} at S_{or}	0.780	0.18	0.15	0.216
Bubble point pressure, psi	1395	1382	290	305
Reservoir pressure, psi	1591	1600	485	420

In order to examine the polymer front between an injector and a producer, 3D models were established based on the description for each field. For vertical wells, the length of the polymer bank was presented in the *x*-direction in the model, and for horizontal wells, the it was presented in the *y*-direction, as illustrated by Figure 7.

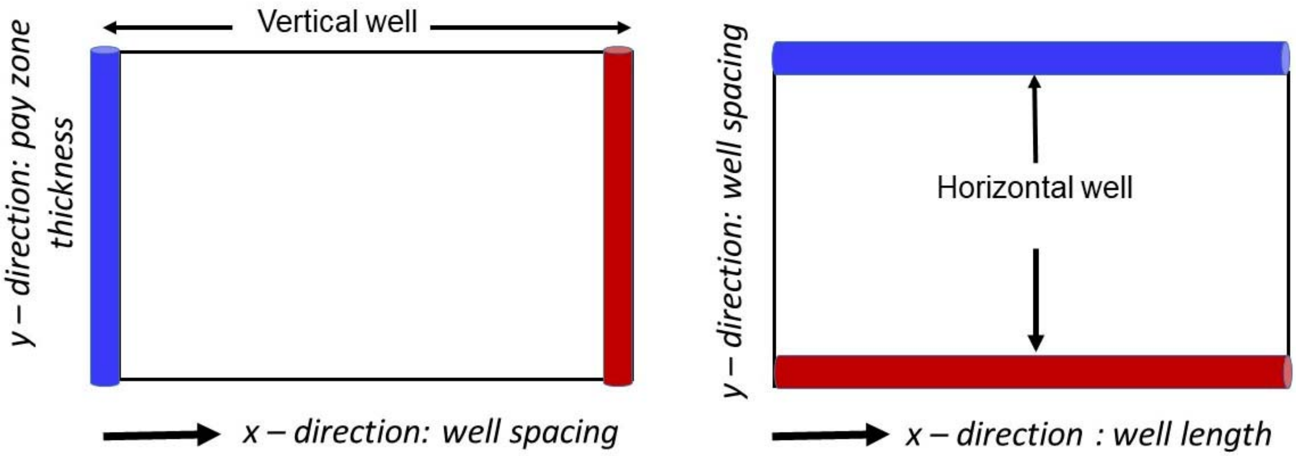

Figure 7—Illustration of polymer advancing direction in simulation models

Pelican Lake: Parallel Horizontal Wells. 800-3000-cp Oil.

The Pelican Lake field (sometimes called Brintnell) in northern Alberta, Canada covers an area approximately 51 km by 42 km. The reservoir was discovered in 1978 and contains about 6.4 billion bbl OOIP. Oil viscosities range from 800-80,000 cp, but the bulk of the polymer flooded area has a viscosity of 3000 cp or less. Up to 900 horizontal wells have injected up to 300,000 bbl of HPAM solution, resulting in up to 67,000 BOPD (attributed to polymer flooding) from ~1400 horizontal production wells (Delamaide 2021). Typical injector-producer spacing is either 100 or 200 meters and horizontal well lengths are typically 1500-2500 meters. Porosity and permeability of this unconsolidated sand averages roughly 30% and 1 darcy, respectively, and formation thickness typically ranges from 3 to 6 meters. Recovery factors are projected to be 6% due to primary and 15% due to waterflooding after primary (CNRL website 2021, Delamaide 2021). Polymer flooding directly after primary provides an average recovery factor of 28%, while polymer flooding in a tertiary mode (i.e., after waterflooding) provides a projected average of 22% (CNRL website). Produced water cuts are typically between 57% and 69% (CNRL 2018). No explanation was given for why polymer flooding directly after primary performed better than polymer flooding after waterflooding. Voidage replacement ratios targeted a value of one, but substantial variations occurred (Delamaide 2021).

Typically, the viscosities of the injected polymer solutions at Pelican Lake were 15-30 cp (measured at 7.3 s^{-1} and 25°C). Given the high oil viscosity, an important question is whether the project would have seen improved performance by injecting a more viscous polymer solution. A number of rationalizations have been used to justify injecting such a low-viscosity polymer solution to displace a very viscous oil. First, losses of injectivity were feared. However, the weak Wabiskaw Formation at Pelican Lake has consistently shown few injectivity losses, regardless of injectant. Second, high polymer costs were argued to limit the economics of injecting more viscous polymer solutions. In contradiction, this concern is mitigated because (above 10-cp) polymer viscosity increases with the 1.9 power of polymer concentration (Seright 2017). So, doubling the viscosity only requires a 1.4X increase in polymer viscosity. Third, the relative permeability to water (k_{rw}) may be very low (e.g., 0.03), thereby requiring a low-viscosity polymer solution to achieve a favorable mobility ratio (Seright et al. 2018). This is a legitimate reason, but an effort must be made to establish that the relative permeability to water actually is low. In fact, extensive studies associated with the Cactus Lake viscous oilfield, k_{rw} values around 0.03 were reported (Seright et al. 2018)

Public information about oil-water relative permeability curves for Pelican Lake is scarce. Delaplace et al. (2013a,b) reported endpoint relative permeabilities of water from 0.1 to 0.15, with Corey exponents of ~3.8 for water and ~1.9 for oil. Delamaide et al. (2014) reported that injection of 20-cp polymer solutions provided a mobility ratio of ~16 at Pelican Lake. Injected polymer viscosities have typically been from 15-30-cp (Delamaide 2021a), indicating that the flood has generally operated with a substantially unfavorable mobility ratio even during polymer injection.

Delamaide (2016, 2021) noted that higher recovery factors were associated with injecting polymer directly after primary production, compared with waterflooding before the polymer flood. Polymer injection directly after primary production was most likely to cause a definitive increase in oil production rate, in addition to reducing the produced water cut. In contrast, polymer injection after waterflooding might reduce water cut, but generally did not increase the oil production rate. As expected, better oil-recovery responses to ~20-30-cp polymer flooding occurred in parts of the field with lower oil viscosities—i.e., less unfavorable mobility ratios.

When waterflooding before polymer flooding a viscous oil, Skauge et al. (2014) demonstrated that viscous fingers form pathways to the production well, and these fingers, in turn, serve as pathways for much of the incremental oil flow during subsequent polymer injection. Oil response to polymer injection is expected fairly quickly for this situation (Skauge et al. 2014). Consistent with this suggestion, the response to polymer injection typically occurred after 9-12 months (Delamaide 2021). If the mobility ratio remains unfavorable (as at Pelican Lake), the domination of flow through the fingers means that pressure gradients in the oil bank will not increase significantly. So, although the water cut should decrease during polymer injection, the oil production rate may not increase significantly—just as observed at Pelican Lake.

Simulation Results. Simulations were performed to estimate the pressure gradient in the oil bank during polymer injection under Pelican Lake conditions. Simulations were performed using CMG IMEX and properties listed by Delaplace et al. (2013a,b) and Delamaide et al. (2014). The relative permeability curves for these Pelican Lake simulations are shown by the black curves in Figure 6.

The predicted pressure gradients in the oil bank are shown by the dashed black curve in Figure 8. This curve is qualitatively consistent with the black curves in Figure 3 (i.e., for unfavorable polymer/oil mobility ratios). The implication here is that increased injected polymer viscosity will decrease mobility ratio and improve recovery efficiency. However, we must point out that these simulations do not incorporate viscous fingering associated with the unfavorable mobility ratio at Pelican Lake. As mentioned in the discussion associated with Figure 3, in reality, viscous fingering and the vertical equilibrium phenomenon will inhibit or prevent increases in pressure gradient in the oil bank. Thus, as predicted by in the green curve in Figure 3, one would expect water cut and sweep efficiency at Pelican Lake to benefit from increasing injected polymer viscosity to achieve a polymer/oil mobility ratio closer to one.

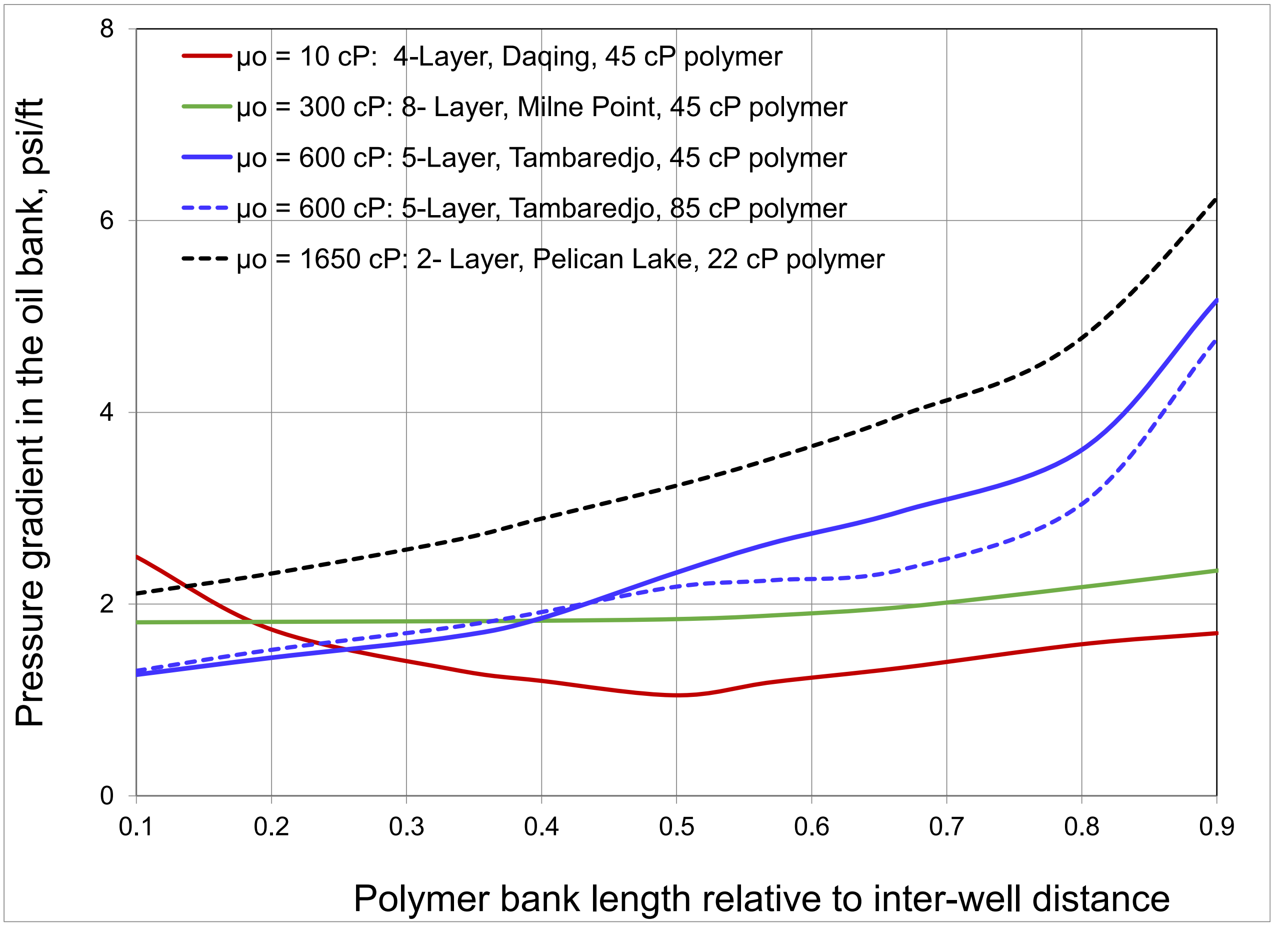

Figure 8—Simulation predicted pressure gradients in the oil bank at various oil field conditions

Perhaps, the main consideration that inhibits injection of higher polymer viscosities at Pelican Lake is the government-mandated maximum injection pressure of 7 MPa. Delamaide (2021) plotted wellhead injection pressures for various parts of the Pelican Lake field. In the western part of the field, the average injection pressure averaged about 10% below the government-mandated maximum (7 MPa), so little room is available there to increase injected polymer viscosity (if the same rate is to be maintained). However, in the eastern part of the field, injection pressures averaged over 40% below the maximum pressure mandate. Thus, it appears that improvements in sweep could be made by increasing injection viscosities in that part of the field.

Delamaide (2021) noted that no correlation existed between well spacing and oil recovery. However, by using tighter spacing and the same injection pressure constraints, our analysis suggests that Pelican Lake could benefit by injecting more viscous polymer solutions—i.e., achieving a polymer/oil mobility ratio closer to unity and increasing pressure gradients in the oil bank.

Milne Point: Parallel Horizontal Wells. 300-cp Oil.

The Milne Point field is a large, viscous oil reservoir on the North Slope of Alaska. A polymer flood pilot project has been underway since August, 2018. Oil viscosity at reservoir conditions is about 300 cp. Formation thickness is 15-30 ft. A number of publications describe details of this project (Dandekar et al. 2019, 2020; Ning et al. 2019, 2020; Wang et al. 2019; Chang et al. 2020; Wang et al. 2020; Zhao et al. 2020; Wang et al. 2021; Zhao et al. 2021; Dhaliwal et al. 2021; and Seright and Wang 2022). The pilot is at the J-pad of the Milne Point Unit and consists of two horizontal injectors (J-23A, J-24A) and producers (J-27, J-28) drilled into the Schrader Bluff NB-sand. The horizontal wells range from 4,200 to 5,500 ft in length, and the inter-well distance varies from 1,100 to 1,500 ft. Before the polymer pilot, this pattern was waterflooded, which was terminated when the oil recovery was only 7.6% OOIP and water cut reached 70%. The initial polymer concentration was 1,750 ppm (45-cp at 7.3 s^{-1}, 25°C), which was reduced to 1,500 and later to 1,200 ppm (30-cp at 7.3 s^{-1}, 25°C). A low-salinity water (2,600 mg/l total dissolved solids, TDS) was used to prepare the polymer solution. The target for the injected polymer solution viscosity was to achieve a unit polymer/oil mobility ratio. At the start of the project, 1750-ppm HPAM was injected, that provided a viscosity of ~45 cp at 7.3 s^{-1}. However, after recognizing that the actual effective average shear rate in the reservoir was about 1 s^{-1} (because of the horizontal wells), the target polymer concentration was reduced to 1200 ppm. Extensive measurements of relative permeabilities (green curves in Figure 6) and other properties relevant to the Milne Point project suggest that the current operation is providing a near-unit mobility displacement of the oil. In apparent contradiction, polymer breakthrough in Production Wells J-27 and J-28 occurred after only 10% PV of polymer injection. However, extensive studies and the available evidence indicated that this early breakthrough was due to polymer channeling through fracture-like features—and not due to viscous fingering associated with an unfavorable mobility ratio.

Simulation Results. Extensive simulation efforts to describe the behavior during the Milne Point polymer flood can be found in Wang et al. 2021. In the current work, we focus on the pressure gradients anticipated within the oil bank during the polymer flood. In the model which generated the green curve in Figure 8, eight vertical layers were used in the simulation model to represent the NB sand in the Milne Point field. This green curve is qualitatively consistent with the green curve in Figure 3—where the predicted pressure gradient within the oil bank remains fairly constant for most of the polymer flood.

In addition, in order to compare the pressure barrier development in viscous oil reservoirs, an eight-layer model with same reservoir conditions (of the Milne Point field) was used during simulations with various oil viscosities. In the base case, 45-cp polymer was injected to displace the viscous oil. The base case was anticipated to provide a near unit-mobility displacement. Consistent with the green curve in Figure 3, the predicted pressure gradient within the oil bank remains fairly constant for most of the polymer flood.

The other curves in Figure 9 show predictions, assuming the oil in the reservoir was more viscous than 300-cp. Consistent with the black curves in Figure 3, the predicted pressure gradients within the oil bank become greater as the polymer flood progresses and as the reservoir oil becomes more viscous (because of the increased polymer/oil mobility ratio as the oil viscosity is raised while keeping the polymer viscosity fixed at 45 cp) at a certain polymer injection volume (0.67PV). We suspect that the increase in pressure gradient will not actually materialize within the oil bank because of viscous fingering and vertical equilibrium effects.

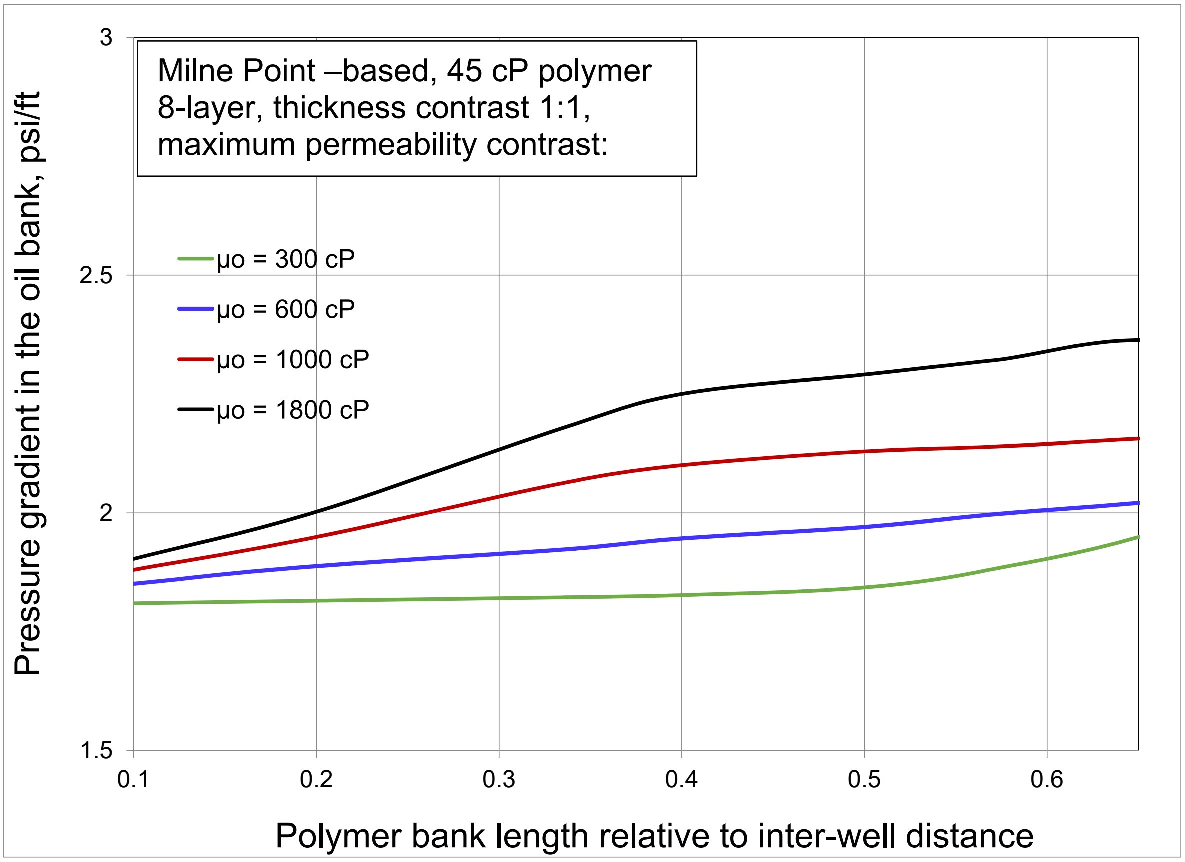

Figure 9—Simulation predicted pressure gradients in the oil bank at Milne Point –based (eight-layer)

Daqing: Vertical Wells. 10-cp Oil.

Daqing has been the largest polymer flood in the world since 1996. Many papers are available that describe this project (Wang et al. 1995, 2000, 2001a,b; Xia et al. 2004;Wu et al. 2007; Wang et al. 2008a,b, 2009; Guo et al. 2021). The oil viscosity associated with the main polymer flood was about 10 cp at 45°C. Five-spot patterns of vertical wells were used, typically with 250-meter well spacing. Multiple strata are present—some with free crossflow between layers and some without crossflow. Total net pay averages around 18 m. Polymer injection wells have been proven to have open fractures during polymer injection (Wang et al. 2008a). Interestingly, the Daqing experts felt that these fractures were oriented horizontally, despite the formation depth around 1000 meters subsurface (Wang et al. 2008a). Much of the polymer flood involved injection of 45-cp HPAM. Endpoint relative permeability to water was 0.78.

In another important part of the Daqing polymer flood, 150-300-cp polymer was injected in attempt to reduce the capillary-trapped residual oil saturation below that obtainable by extended waterflooding (Wang et al. 200, 2001a,b; Xia et al. 2004; Wu et al. 2007; Jiang et al. 2008; Wang et al. 2011; Guo et al. 2021). Interestingly, no evidence of injectivity problems were reported, even during injection of 150-300-cp polymer. Injectivity was reported to be only about 10% less for 200-300-cp polymer than for 40-50-cp polymer (Wang et al. 2011). Fracture extension seems the most likely explanation for this observation. Interestingly, no evidence of severe polymer channeling was reported either. Of the field cases considered, this is the case where a polymer pressure barrier is most expected (based on the arguments associated with Figures 3 and 4). Also, this is the case where severe fracture extension and development of severe channeling would have been expected. In speculating a reason why these phenomena were not seen, fortuitous fracture extension seems a possible explanation. Perhaps, the key is horizontal fractures. As illustrated in Figure 5, polymer injection could continually extend the fracture as it leaks off along the fracture faces—efficiently sweeping the oil (assuming the zone is not too thick).

Simulation Results. Reservoir properties and polymer properties for numerical simulation associated with this simulation effort can be found in Wang et al. 2000, 2001a,b; Xia et al. 2004; Wu et al. 2007; Jiang et al. 2008; Wang et al. 2011; Chen et al, 2015; Guo et al. 2021. Four vertical layers were used in the simulation model to represent the major pay zone of Pu I- II strata in Daqing field. The red curve in Figure 8 shows the prediction from the simulation effort for Daqing. Qualitatively consistent with the red curves in Figure 3, the simulation predicted a decline in injectivity and in pressure gradient within the oil bank as the polymer progresses through the reservoir (except for the artifact where pressure gradients increase as polymer approaches the production well). As mentioned above, this behavior and a polymer induced pressure barrier did not appear to materialize in the actual Daqing field application. We suggest that the discrepancy can be explained by fracture extension during polymer injection—as illustrated in Figure 5.

Tambaredjo: Vertical Wells. ~600-cp Oil.

The Tambaredjo reservoir (Suriname) is a 12-darcy reservoir containing ~600 cp oil. During primary production, ~20% OOIP was recovered, by solution-gas and compaction drive. Polymer pilots were developed using vertical wells in 5-spot patterns with ~135-meter spacing (Moe Soe Let et al. 2012; Manichand et al. 2013; Manichand and Seright 2014; Delamaide et al. 2016a,b,; Wang et al. 2017). The pilot area was described by permeability of 4-12 darcies, and two beds (T1 & T2) with a 12:1 permeability contrast (free crossflow, 20-ft thickness for the most-permeable layer and 15-ft thickness for the second layer). Initially, the project injected ~45-cp HPAM solutions into vertical wells that were proven to have open horizontally-oriented fractures or fracture-like features. Based on arguments raised in Seright (2017), injected polymer viscosities were increased in stages to as high as 165 cp (at 7.3 s^{-1}, 25°C). Unfortunately, injection of the more viscous polymer solutions did not improve performance of the polymer flood. The reasons for this have been debated (Delamaide et al. 2016a,b; Wang et al. 2017), but one possibility raised was that pressure barriers may have been created during injection of the more viscous polymer solutions.

Although the oil-displacement mechanism illustrated in Figure 5 could explain the viscous polymer injection at Daqing, why did it not appear to work at Tambaredjo in Suriname? Tambaredjo was a shallower field (~300-meter depth) with a single, thin formation, so horizontal fractures and the above mechanism are more easily justified there than at Daqing.

Simulation Results. Reservoir and polymer properties associated with this simulation effort can be found in Bhoedie, et al, 2014; Delamaid et al, 2016; Wang et al. 2017. Five vertical layers were used in the simulation model to represent the T1 & T2 strata in the Tambaredjo field. The two blue curves in Figure 8 show the predicted results (from simulation), assuming 45-cp and 85-cp polymer, respectively. Both of these cases involved polymer/oil mobility ratios greater than one. So, consistent with the black curves of Figure 3, pressure gradients within the oil bank (and injectivity) were predicted to increase with increased polymer throughput. Since higher injected polymer viscosities did not increase oil recovery performance at Tambaredjo (Delamaide et al. 2016, Wang et al. 2017), an explanation is needed. One possibility is that the assumed relative permeability curves for this case may have been incorrect—so that the injected 45-cp polymer actually provided a polymer/oil mobility ratio near unity. In that case, a pressure barrier could have developed during injection of the more viscous polymer solutions. This observation emphasizes the importance of measuring relative permeability characteristics for these polymer floods. However, we note that other explanations have been proposed for the lack of improved performance at Tambaredjo, including (1) unconfined patterns during the polymer pilots, (2) viscous polymer injection countering a significant compaction drive, and (3) formation damage at production wells inhibiting collection of displaced oil (Wang et al. 2017).

Conclusions

1. During polymer flooding, this work suggests that under most circumstances, the optimum injectivity (i.e., least likelihood of developing a polymer-induced pressure barrier) and the greatest pressure gradient within the oil bank will be achieved with a polymer/oil mobility ratio near one.
2. Our current work suggests that a previous analysis (Seright 2017) may have over-predicted the most desirable polymer viscosity for polymer flooding a heterogeneous reservoir with free crossflow between layers. That previous analysis correctly predicted that the optimum sweep efficiency would result from a polymer viscosity (relative to water) that was the waterflood endpoint mobility ratio times the permeability contrast. However, the current work reveals that excessive pressure barriers could develop with that approach.
3. A pressure barrier due to the injected polymer bank is not likely to materialize for viscous oil reservoirs such as Pelican Lake, or Milne Point.
4. At Milne Point, where the target polymer/oil mobility ratio is near one, analytical and simulation results support achievement of the optimum injectivity and greatest pressure gradient within the oil bank.
5. At Pelican Lake, by using tighter spacing, our analysis suggests that Pelican Lake could benefit by injecting more viscous polymer solutions. Also, in the eastern part of the field (where the government-mandated injection pressure is generally not limiting), recovery efficiency might benefit from injection of higher polymer concentrations—i.e., achieving a polymer/oil mobility ratio closer to unity.
6. Although injection of viscous polymer solutions (up to 165 cp) clearly did not improve sweep (over 45-cp polymer) at the Tambaredjo field, the observed injectivity reductions seem unlikely to be due to development of a polymer pressure barrier, unless the true endpoint permeability to water was much lower than the value assumed during simulations.
7. Although a severe pressure barrier was anticipated for the Daqing polymer flood (~10-cp oil), it clearly did not materialize, even with injection of 150-300-cp HPAM solutions. During polymer injection, fortuitous extension of (horizontal) fractures may explain why problems did not develop with injectivity reduction, pressure barriers, and channeling associated with excessive fracture extension.

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Nomenclature

k = permeability, darcys [μm^2]
k_{ro} = relative permeability to oil
k_{rw} = relative permeability to water
L_o = length of the oil bank, ft [m]
L_p = length of the polymer bank, ft [m]
L_t = total distance from injector to producer, ft [m]
M = polymer/oil mobility ratio
Δp_o = pressure drop across the oil bank, psi [Pa]
Δp_p = pressure drop across the polymer bank, psi [Pa]
Δp_t = pressure drop from injector to producer, psi [Pa]
PV = pore volumes of fluid injected
ΔPV = pore volumes difference
S_{or} = residual oil saturation
Δt = incremental time, hr
v = velocity, ft/d [m/d]
v_i = initial velocity, ft/d [m/d]
ϕ = porosity
ρ_{rock} = rock density, g/cm^3

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SI Metric Conversion Factors

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

* Conversion is exact.