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Polymer Flooding a ~500-cp Oil

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Abstract

Relatively high oil prices, modest polymer prices, and advances that promote higher injectivity for polymer solutions have allowed polymer flooding to be applied in reservoirs with notably more viscous oils than in previous years. This paper describes a polymer flooding pilot project in the Tambaredjo field in Suriname. The average viscosity of the produced oil is ~1,700 cp, but solution gas reduces the effective oil viscosity in the reservoir to 400-600 cp (through the "foamy oil" mechanism). Interestingly, the primary drive mechanism in the pilot area is compaction—leading to ~20% OOIP recovery. Because various restrictions preclude application of thermal methods, polymer flooding was explored as a means to enhance oil recovery. The average permeability of the sand exceeds 4 darcys, but the level of heterogeneity is significant (>10:1 permeability contrast is common). The first simulation efforts suggested that injection of 25-40-cp polymer solutions might be optimum, considering both displacement and injectivity. Consequently, ~40-cp polymer solutions were injected during the first part of the pilot. However, later analysis revealed that sweep efficiency could be improved significantly using polymer solutions up to 160 cp. Although injection was done at pressures below what was believed to be the formation parting pressure, injectivity data from several water injection cycles shows that partition of the formation followed by partial sustenance of the fracture did occur. Analysis of produced water salinities, polymer and tracer concentrations, water/oil ratios (WOR), and inter-well pressure responses all indicated that severe channeling (i.e., through fracture-like features) did not occur. Instead, analysis of the project response indicated that (1) sweep could benefit from injecting more viscous polymer solutions, (2) injectivity for more viscous polymers would not be a problem because of controlled (i.e., not detrimental) fracture extension, and (3) oil production rates could be enhanced (without sacrificing WOR) by increasing injection rates. Consequently, these ideas are currently being field tested in our project. This paper details results to date for this polymer pilot.

Introduction

This paper documents a review and analysis of Staatsolie's Sarah Maria polymer flooding pilot project in the Tambaredjo field (Suriname). The polymer pilot (**Fig. 1**) currently has three injection wells (1M101, 1N062, and 1M052) with nine offset production wells (1M09, 1M10, 1N06, 1M051, 1N11,1N061, 1M04, 1M05, and 1125). The ultimate question for the pilot is whether and/or how the project should be expanded to some of the other ~1,000 wells in the field. Making this assessment requires (1) quantification of oil recovery and water cut responses to polymer injection, (2) an understanding of the mechanism of action and possible deficiencies/limitations for the polymer for the current pilot operation, and (3) identification of possible improvements that could make polymer injection more effective.

The Reservoir and Pilot Project

Primary Drive Mechanism. In addition to solution gas drive, compaction has been largely responsible for the 20% OOIP recovery factor associated with primary recovery in the pilot area. The compressibility of the field appears 100 times greater than an average compressibility factor used to model heavy oil reservoirs in western Canada. No active water drive in this part of the field is evident, and no waterflood has been implemented. A combination of rock and fluid expansion and rock compaction appear to be responsible for most formation water produced from the project area.

Effective Oil Viscosity. To supplement the compaction and solution gas drive mechanisms, polymer injection is being evaluated. High oil viscosity in the Tambaredjo Field mandates that polymer injection is preferred over water injection. Uncertainty exists about the effective oil viscosity in the reservoir. Produced oils range in viscosity from 1,260 to 3,057 cp, with an average of 1,728 cp. However, modeling the flow behavior in the reservoir requires acceptance of a much lower oil

viscosity level to justify oil production rates. Current beliefs about effective oil viscosity in the reservoir range from 300 to 600 cp. The concept of "foamy oil" was used to rationalize the relatively low oil viscosity that was used in the simulation models (Manichand *et al.* 2010). 300 cp was noted as the lowest effective oil viscosity during the modeling, and values of this magnitude are being used currently during in-house simulations. Water viscosity at reservoir temperature (100ºF, 38º C) is about 0.7 cp.
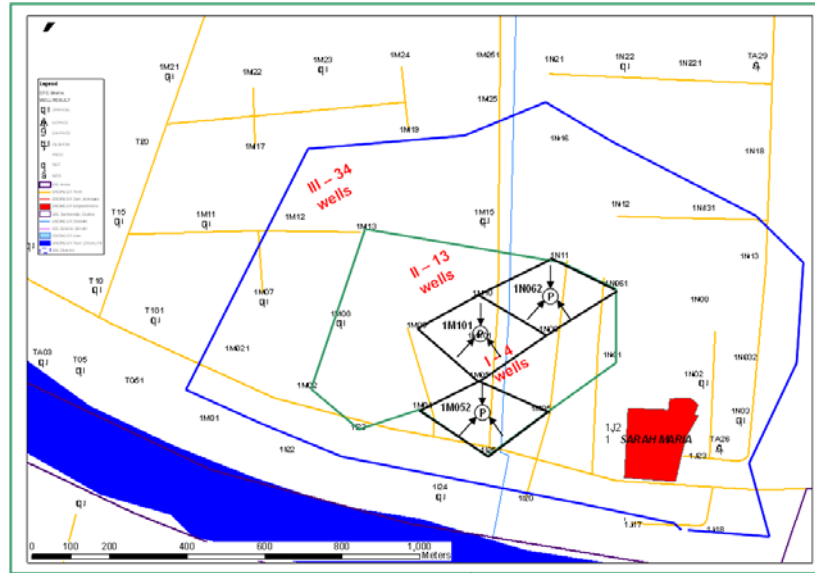

Fig. 1—Sarah Maria polymer pilot project.

Permeabilities. Formation permeability directly impacts injectivity, which in turn impacts how rapidly oil can be displaced and produced. The permeability implied from injection or production data represents a composite of the permeabilities of the strata and fracture (or fracture-like) flow features in the formation. Justification of the oil production rates required assignment of average permeabilities for the T1 sand ranging from ~4 darcys to ~12 darcys. These high values were also consistent injection rates observed during a water injectivity test. The description for the T1 facies of core from Well 1M101 included (1) "medium to fine-grained sandstone with planar and some cross stratification", (2) "fine to very fine-grained sand with ripples, and (3) shaly sand. **Fig. 2** shows a grain size distribution for cores from Well 1M101. This distribution is representative of many that were determined. It shows a peak in size frequency at 0.3 mm. However, the core recovery in this well was very low due to the unconsolidated sand. Hence, the grain size analyses may be more representative of the poor parts of the reservoir.
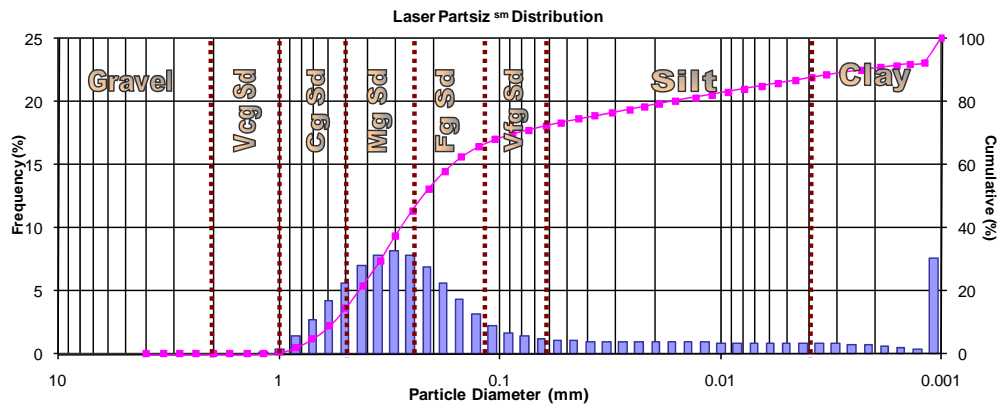

Fig. 2—Analysis of core from Well 1M101.

Relative Permeabilities. Different relative permeability curves were used during two simulation efforts. The first set of curves used S_{wi}=0.2, S_{or}=0.25, k_{ro}=1, k_{rw}=0.25, no=1.13, nw=2.65 to 4. (no and nw are saturation exponents in the relative permeability equations shown by Eqs. 1 and 2.) The second simulation effort used S_{wi}=0.23, S_{or}=0.25, k_{ro}=1, k_{rw}=0.07, no=2-3, nw=2.

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

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

The most significant difference for the two sets of curves is the endpoint relative permeability, k_{rw}: 0.25 for the first simulation effort and 0.07 for the second. This value directly affects the water/oil mobility ratio, which in turn affects the efficiency of oil displacement. The second set of relative permeability values was regarded as most appropriate (because they were derived from Tambaredjo core and fluids, while the first set of values were based on work in Ottawa sand packs) and has been accepted for recent simulations. However, the first set of values was used in the original design of polymer viscosity and concentration.

Mobility Ratio. Mobility ratio $[(k/\mu)_{water}/(k/\mu)_{oil}]$ directly impacts how efficiently an aqueous phase will displace oil. Given water viscosity of 0.7 cp and oil viscosity of 400 cp, the endpoint mobility ratio is 143 using the first set of relative permeability values and 40 using the second set. For displacement of oil from a single homogeneous layer, ideally the mobility ratio should be reduced to unity. Consequently, the ideal polymer solution viscosity (assuming only one homogeneous layer) would be 143 times that of water using the first relative permeabilities and 40 times that of water using the second relative permeabilities. Interestingly, the first simulation effort suggested that 25-40 cp polymer would be acceptable. Oddly, the simulations indicated that viscosity increases beyond 25 cp resulted in only small increases in incremental oil recovery. This conclusion was troubling since basic physics says that (even in a homogeneous porous medium) recovery efficiency will improve until the mobility ratio is reduced to unity (i.e., requiring a polymer solution viscosity of 143 cp in one case). The presence of any heterogeneity raises the need for even higher polymer viscosities and concentrations (Seright 2010). These facts are documented in basic reservoir engineering textbooks (Craig 1971, Lake 1989).

Reservoir Stratification. Increased heterogeneity in a reservoir increases the need for higher polymer concentrations (Sorbie and Seright 1992, Seright 2010). A key benefit of polymer flooding is that sweep efficiency increases as the injectant viscosity increases. In reservoirs with free crossflow (as in Tambaredjo's T1 sand), accepted reservoir engineering (Craig 1971, Lake 1989, Sorbie and Seright 1992) reveals that sweep efficiency in the less-permeable layer is roughly proportional to the mobility contrast divided by the permeability contrast {i.e., $[(k/\mu)_{polymer}/(k/\mu)_{water-oil}]/(k_1/k_2)$}. Videos of experiments that demonstrate this concept can be found at http://baervan.nmt.edu/randy.Thus, as polymer concentration and viscosity are increased, significant increases in recovery efficiency are expected until [1/(mobility ratio)] exceeds the permeability contrast (Sorbie and Seright 1992).

A significant level of heterogeneity exists in the Tambaredjo reservoir. For example, Table 1 lists assigned permeabilities, porosities, and thicknesses for the T1 and T2 layers associated with Well 1M101. Note the 12:1 permeability contrast between the middle T1 (12011 md) layer and the top T1 layer (976 md). Thus, the model incorporated a substantial level of heterogeneity (permeability contrast around 10:1 or greater).

Table 1—Properties of T1 and T2 Layers in the Simulation Model.

Zone	Permeability, md	Porosity, %	Thickness, ft
T2	1		3
T2	16		3
T2	12		3
T2	22		3
T2	44	19	3
T1	976	28	4
T1	1610	30	4
T1	12011	34	4
T1	9744	32	4
T1	3236	28	4

The first simulation effort indicated little improvement in oil recovery by injecting more than 25-cp polymer solution. A similar finding was noted during the second simulation effort. As mentioned above, basic reservoir engineering concepts conflict with these findings. We suspected that the discrepancy reflects a quirk with the simulations. Perhaps, the discrepancy arises because only 6-7 horizontal cells separate the injector and producer in the simulated polymer pilot. This may not be enough cells to properly represent polymer transport or action in the reservoir. Another possibility is that high concentrations and polymer viscosities, along with the assumption of no near-wellbore fractures may create an artificial "pressure block" near the well, which inhibits transfer of the injection energy to the grid blocks away from the injection well. The simulator indicated high polymer adsorption and pore blocking when higher polymer concentrations were used. This effect is possible for high-molecular-weight polymers in rock with less than 100 md. However, for the high-permeable sands in the pilot area, this effect is unlikely in reality (Seright 2010, Seright *et al.* 2011, Wang *et al.* 2008B). Either way, we were skeptical of simulation results indicating that polymer concentration or viscosity does not matter for the range of conditions considered here. Discussions with others suggest that this may be a common issue with existing polymer flooding simulators. By imposing radial flow in the injection grid blocks, excessive pressures are predicted during polymer injection — which mandates that relatively low polymer viscosities be used in order to achieve economic production rates in the reservoir.

However, in field projects, polymer injection usually occurs above the formation parting pressure (Seright *et al*. 2009, Seright 2010, Van den Hoek *et al*. 2009, Wang *et al*. 2008A). As will be verified shortly, injection above the formation parting pressure removes the artificial restriction to injection that was imposed during the simulations.

Water Quality and Polymer Mixing. The water used for mixing polymer solutions was clear, with no sign of particulates. Polymer solution concentrate was also clear and well-dissolved. Polymer preparation and water quality were uniform, reliable, and consistent, with only occasional upsets. Prepared polymer solutions (1,000-ppm SNF Flopaam 3630S in ~400-500-ppm-TDS Sarah Maria water) consistently had a viscosity ~50 cp (ambient temperature, 7.3 s^{-1}) at the mixing facility and ~45 cp at the closest injection well (1M101).

Dispersion and Mixing When Injecting Lower Salinity Water. At the Sarah Maria polymer project, the salinity of the injected polymer solutions is 400-500 ppm total dissolved solids (TDS), but the formation water typically has ten times higher salinity. HPAM polymers are extremely effective viscosifiers at low salinities, but they lose much of their effectiveness as salinity is raised. We expect the Sarah Maria polymer solution to lose over half its original viscosity if mixing with the formation water increased the salinity to ~5,000 ppm TDS. This type of mixing is most likely to occur if the mobility ratio is high, as at the Sarah Maria project. The mixing occurs because thin viscous fingers penetrate through the formation, so the saline formation water does not have to travel far (by diffusion or dispersion) to mix with the polymer water. As the viscosity of the polymer water is increased, this mixing effect is reduced. So, an incentive exists to inject the most viscous polymer solution that is practical. This concept was effectively demonstrated in German polymer floods where fresh-water polymer solutions were injected into formations with 17% TDS brines (Maitin 1992).

Project Results

Tracer Results and Polymer Breakthrough. Polymer injection into Well 1M101 began in September 2008. Injection rate varied from a high of 335 BPD (October 2008) to 160 BPD (December 2011). As of December 2011, 261,472 bbl of polymer solution had been injected into Well 1M101. Polymer injection into Well 1N062 began in May 2010 and has continued with rates between 220 and 320 BPD. As of December 2011, 162,492 bbl of polymer solution had been injected into Well 1N062. The amount of 10 kg of a 30% solution of the tracer, sodium 2-fluorobenzoate, was injected into injector 1N062 on May 19, 2010—immediately before the start of polymer injection. This tracer was claimed not to partition into the oil phase or to be chemically or biologically degraded. However, this tracer was never definitively detected in any well. Polymer injection in a third well, 1M052, began in June 2011. As of December 2011, 40,697 bbl had been injected at rates varying between 150 and 260 BPD. The amount 10 kg of a different tracer, sodium 4-fluorobenzoate, was injected immediately before polymer injection. This tracer was first detected (0.8 ppb) after nearly one month in Well 1I25 located south of the injection well and continued to be produced (174.4 ppb) after two months. Considering the pore volume of all three injection patterns, approximately 16% PV of polymer solution had been injected as of December 2011.

  Polymer breakthrough was modest and gradual in the first injection pattern, being detected in the producers located west and north of the injector. In the second injection pattern, the polymer breakthrough was more evident, and higher concentrations of polymer were produced quickly in wells in the north-south direction. In the third injection pattern, polymer breakthrough also was observed in the south of the injector. In summary, nine wells (offset and non-offset wells) in the surroundings of the injection patterns are producing injection fluid at 10 to 60% of the injected polymer concentration. Polymer breakthrough has not been confirmed yet for the offset producers Wells 1M04 and 1M051. Based on the polymer breakthrough times and concentrations, the level of channeling is significantly greater in the second injection pattern. The geological map in this area also shows a main channel (south to north) near the second injection pattern (**Fig. 3**).

Salinity Response. Water in the injected polymer solutions was considerably less saline (400-500 ppm TDS) than for the formation water (2,500-5,000 ppm TDS). Thus, salinity of the produced water may reflect breakthrough from injection wells. **Fig. 4** plots salinity of the water from the pilot's production wells. The largest and most abrupt salinity drop occurred in Well 1N11—the north well in the second polymer pattern. The response started about one month after the start of polymer injection (into Well 1N062). Most of the salinity decrease occurred over a 5-month period, eventually leveling off at one-quarter of the original salinity (but still about three times the salinity of the injected water). Consideration of the breakthrough time, injection/production rates, and inter-well distance suggests that the "channel" between the injector and producer has a volume of roughly 6,000 barrels. Simple geometric arguments reveal that this channel feature cannot be a fracture because the fracture would have to be about 5 ft wide. (If the feature really was a fracture with a width of only 1 mm, the salinity response should have been detected after only one day under our conditions.) Consequently, the channel appears to be a finger of aqueous fluid in the more permeable sand—not a fracture.

  Relatively quick salinity responses were also seen in Wells 1N06 and 1I25. The magnitudes of these responses are also consistent with viscous fingers, rather than fractures. The responses in Wells 1N11 and 1N06 indicate a north-south channel through Injector 1N062. The response in Well 1I25 suggests a north-south channel through Injector 1M052.

  Gradual salinity declines were noted in Wells 1M09, 1M10, 1N061, and 1M05. No significant salinity change has been noted yet in Wells 1M04 and 1M051. These results indicate that the first polymer pattern shows no sign of channeling in any direction. They also suggest that channeling does not occur in the east-west direction in any of the three patterns.
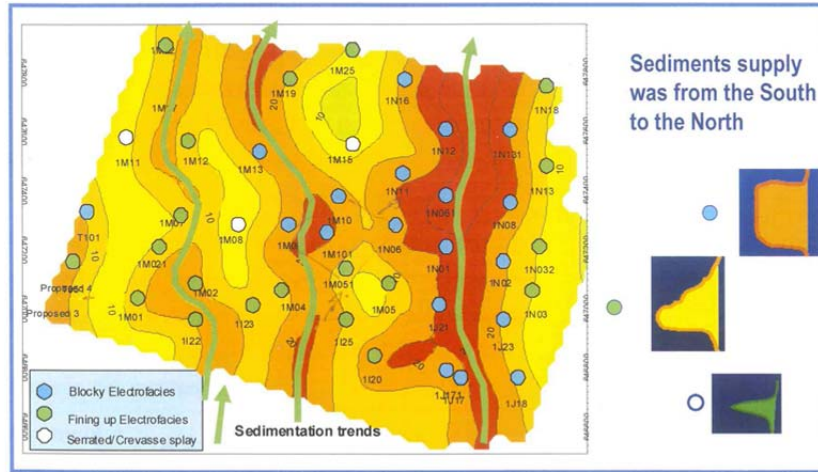
Fig. 3 – T1 Net Sand Map (five-foot contour with red and orange colors indicating the thicker sands)
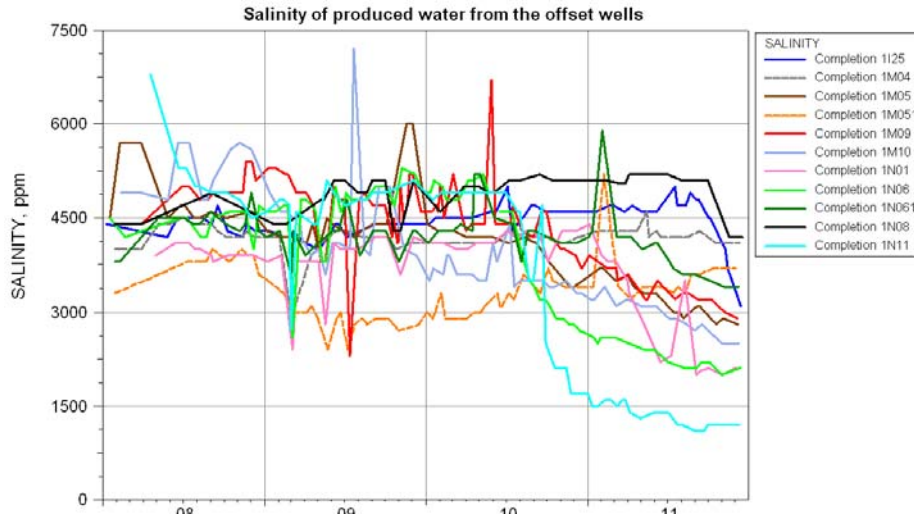

Fig. 4 — Salinity responses in the pilot producers.

For the pilot patterns, it seems likely that the salinity and polymer breakthrough was the natural consequence of viscous fingering (because the injected viscosity is probably not high enough to prevent some channeling). Reduction of this somewhat earlier polymer breakthrough could be achieved by increasing the viscosity of the injection fluid. If fracturing had been a primary source of channeling, breakthrough would have occurred much earlier and more abruptly.
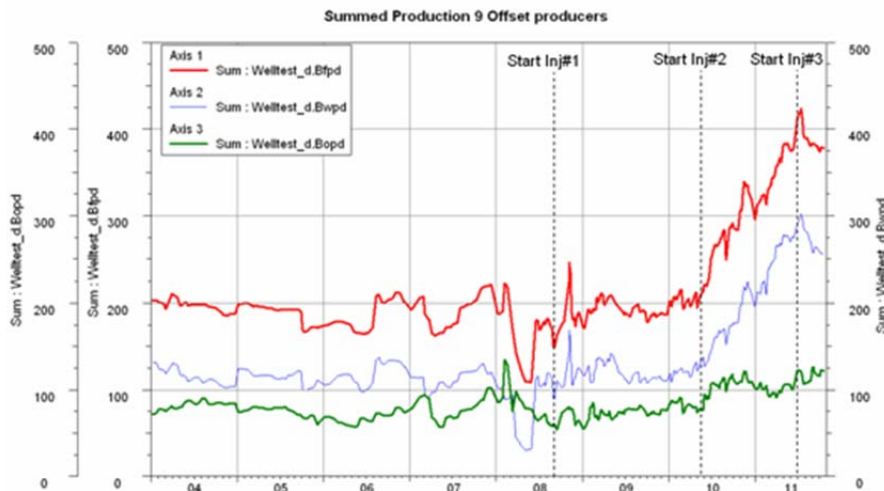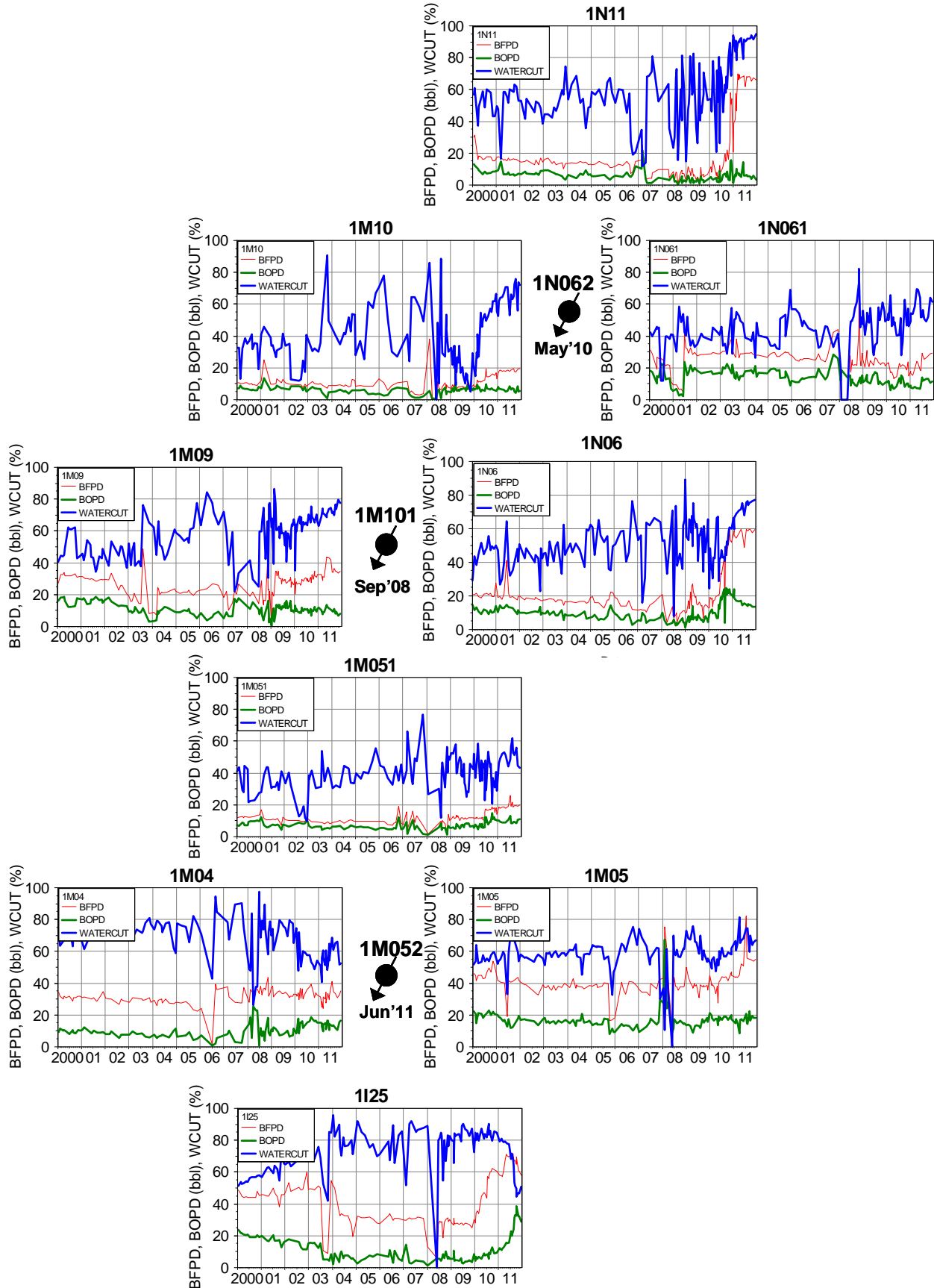

Fig.5—Overall pilot response.

Fig. 6— Individual production graphs for the nine offset wells from the injection patterns.

Oil and Water Cut Responses to Date. An overall view of the performance of the polymer pilot can be seen in **Fig. 5**. This figure indicates a modest response associated with polymer injection into the first injector (1M101) and a noticeably greater response (in oil rate and especially water cut) associated with polymer injection into the second injector (1N062). A marked reduction in water cut occurred after polymer injection in the third injector (1M052). Some interesting insights were gained by looking at individual well responses. **Fig. 6** shows daily oil and water production rates and water cuts for individual wells, while **Figs. 7-15** show cumulative fluid rates (along with instantaneous water cuts).

For the first pattern (associated with Injector 1M101), changes in both water and oil production rates were generally modest from 2008 to 2010. Exceptions were Producers 1M10 and 1N06, where water cuts dropped dramatically until early 2010 (Figs. 6, 7, and 10). Interestingly, Well 1M04 (located about 800 ft southwest of Injector 1M101), showed a steady decline in water cut and increase in oil rate from 2008 to 2010 (Fig. 6). When the second injector (1N062) was put on-stream (May 2010), water cuts increased noticeably (20-30 percentage points) in the north-south Producers 1N11 and 1N06, and in the west Producer 1M10. At the same time, significant increases in oil rates were noted in the north-south Producers 1N11 and 1N06 (Figs. 6, 10, and 11), and also in 1M04 (Figs. 6 and 13). In these wells, oil rates peaked after a few months and then declined. Oil rate changes were less noticeable in the east-west Producers 1M10 and 1N061.

In the third pattern, the response was dominated by the south Producer 1I25. Upon bringing on the third polymer injector (1M052) in June 2011, the oil rate rose and peaked at 40 BOPD and the water cut dropped from 80% to 45%.

A preferred response occurred in the north-south direction from the polymer injection wells. This response is not abrupt as would be expected from directional vertical fractures. Instead, it suggests a matrix permeability preference for the north-south direction (as in a fluvial deposition). The geological maps have also confirmed the channels in this area to be in north-south direction with the best-developed channel near the second injection well (See Fig. 3).

Several different types of responses to polymer injection were noted. First, for the most prominent production well (1I25), water cut decreased and oil rate increased dramatically within a few months after the start of polymer injection. Well 1M04 also fell into this category (in response to polymer injection into 1M101), although the response was more gradual (presumably because the well was relatively far from the injector). Second, for Producers 1N11 and 1N06, both oil rate and water cut increased in response to polymer injection into Well 1N062. Third, for Producers 1M10 and 1N06 when only the first pattern was under polymer flood (2008-2010), a noticeable decrease in water cut occurred without a corresponding increase in oil rate. Fourth, for Wells 1M09, 1M051, 1M05, and 1N061, the response to polymer injection was ambiguous or not apparent.
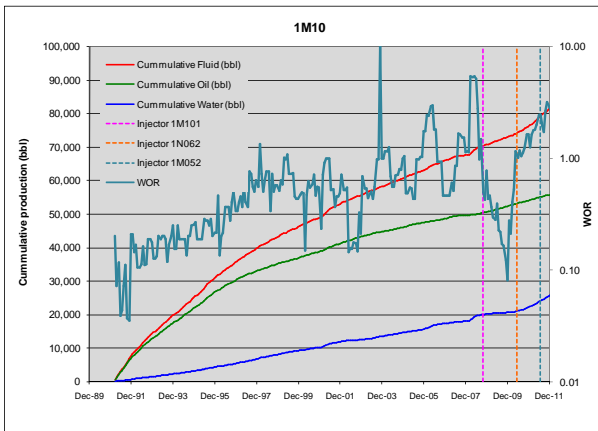
Fig. 7—Cumulative production from Well 1M10.
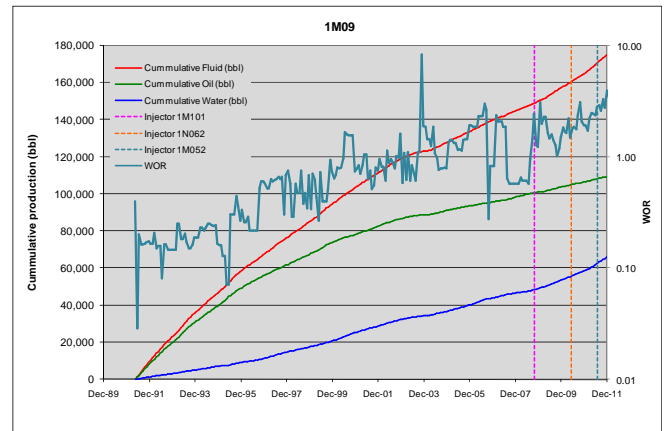
Fig. 9—Cumulative production from Well 1M09.
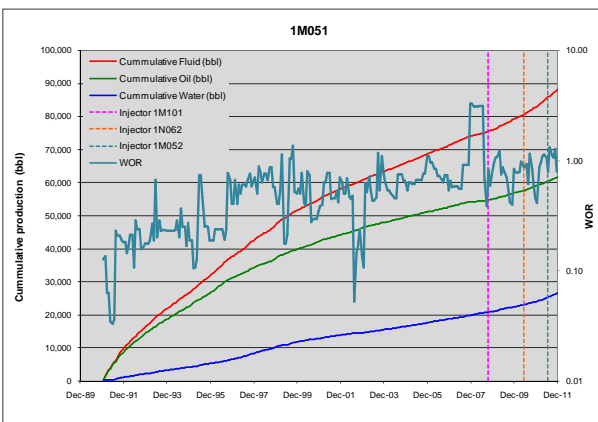
Fig. 8—Cumulative production from Well 1M051.

Fig. 10—Cumulative production from Well 1N06.

Fig. 11—Cumulative production from Well 1N11.

Fig. 12—Cumulative production from Well 1N061.
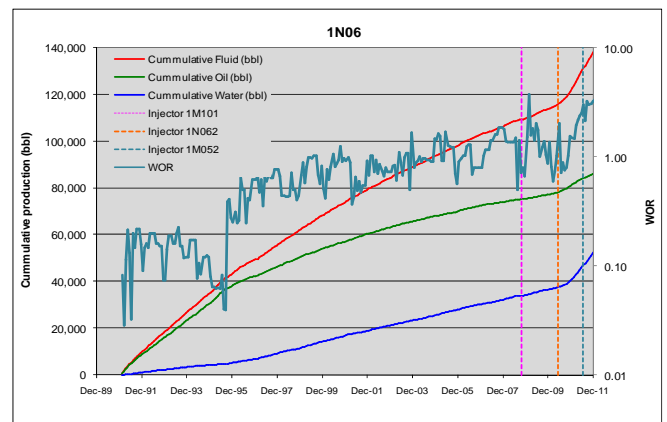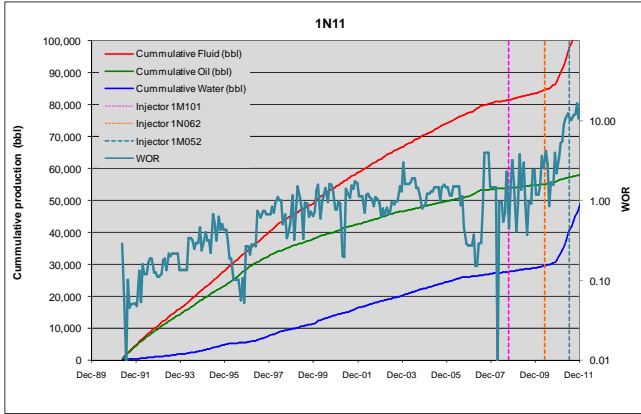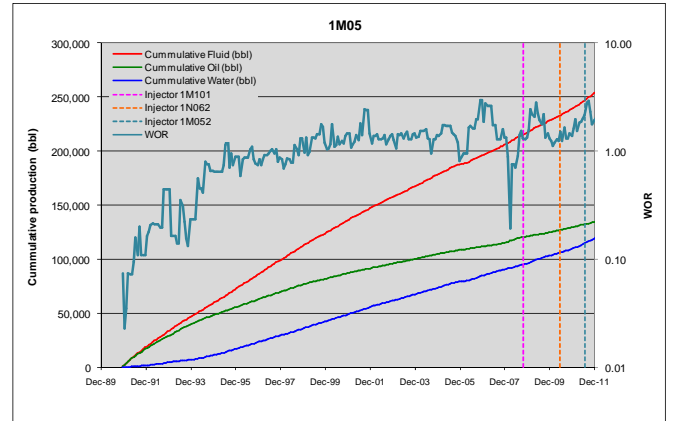

Fig. 13—Cumulative production from Well 1M04.
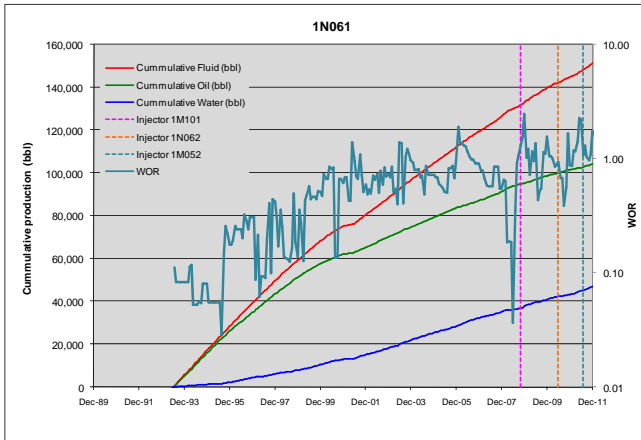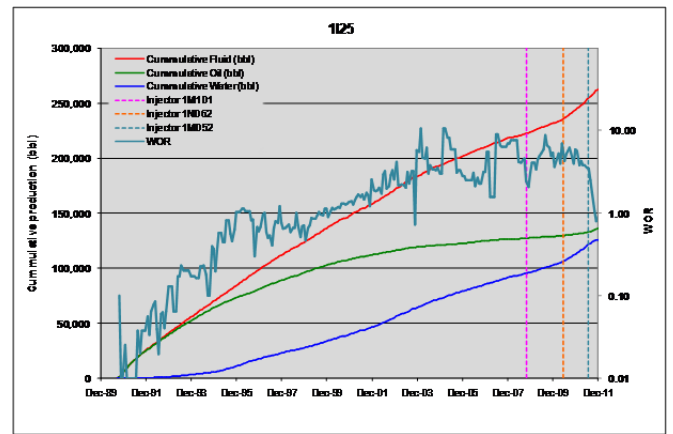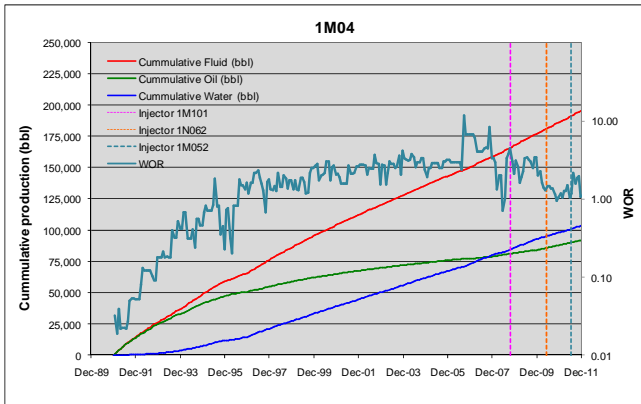

Fig. 14—Cumulative production from Well 1M05.

Fig. 15—Cumulative production from Well 1I25.

Simulator Predictions versus Actual Behavior. The first simulation effort predicted a quick oil increase (less than one year) after polymer injection. The second effort predicted 6 months. When the response occurred in the actual pilot, it often did occur quickly (1-2 months). The first simulation predicted that the water cuts would drop sharply along with the increase in oil rate. Field results showed only modest changes in watercut in some wells and increased oil production was mostly due to augmented fluid production. The first simulation predicted that 34% to 66% OOIP could be recovered from polymer flooding, and that the rate of recovery would depend on injection rate. The first simulation predicted definitive polymer breakthrough in 1M09 by 7/21/09, in 1M10 by 3/23/10, in 1M051 by 4/23/10 (20 months), and in 1M04 by 11/1/10 (26 months). The second simulation predicted breakthrough after 10 months in 1M051 and after 12 months in 1M10. There were difficulties in detecting the period of breakthrough in surrounding producers. Qualitative analysis indicated breakthrough in 1M09 in October 2009 while the quantitative analysis in November 2009 showed only 7 ppm of polymer in the produced water phase. Significant and consistent produced polymer concentrations were successfully determined only since early 2011 and in some wells conflicting qualitative and quantitative produced polymer results were observed. Therefore, changes in salinity trends and measured produced polymer concentrations were used as the basis to analyze polymer flow and breakthrough.

Fig. 16 presents results of fractional flow calculations using the spreadsheets available at http://baervan.nmt.edu/randy. These can be applied to estimate polymer flood response for cases with one layer, two layers with no crossflow, or two layers with free crossflow. The two layers had the same thickness, but Layer 1 was 10 times more permeable than Layer 2. The relative permeability characteristics were: S_{wi}=0.23, S_{or}=0.25, k_{ro}=1, k_{rw}=0.07, no=2, nw=2, and oil viscosity was 300 cp. This model is incompressible, neglects gravity and capillary forces and assumes that polymer solutions are Newtonian, polymer retention balances inaccessible pore volume, and flow is linear between two wells. In Fig. 16, cases are shown for (1) waterflood only, (2) 40-cp polymer, (3) 80-cp polymer, (4) 160-cp polymer, and (5) perfect piston-like displacement. The modest response for most curves that is seen between 0.1 and 0.35 pore volumes (PV) is due to a water bank that is built up ahead of the polymer bank (which basically follows the waterflood behavior. For each polymer flooding case, an oil bank is formed, whose duration is indicated by the steep line segments after 0.35 PV. Note that predicted recovery increases with increasing polymer concentration up to 160 cp.
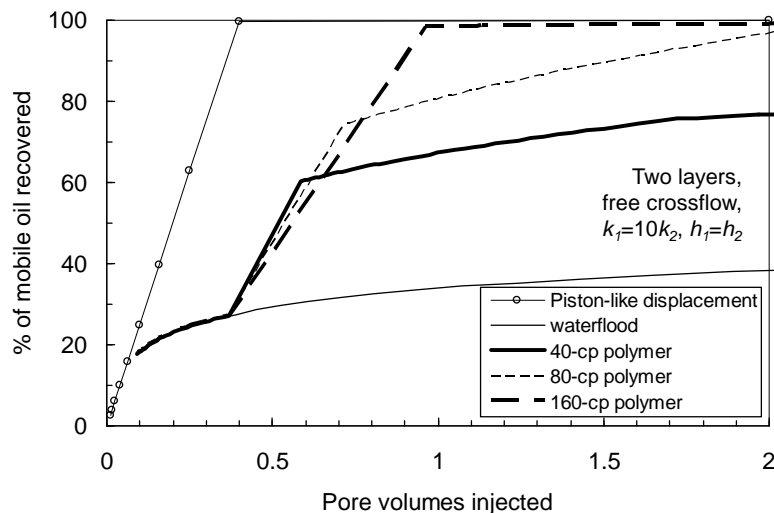
Fig. 16—Fractional flow calculations for a two-layer reservoir with free crossflow.

Injectivity. Injectivity is critically important in polymer floods, waterfloods, and most other EOR projects. Injectivity is defined as injection rate (e.g., in BPD) divided by (downhole pressure in a well minus the average reservoir pressure). This property determines how fast fluids can be injected, which in turn affects how fast oil can be produced. If no fractures or fracture-like features exist in the well, the pseudo-steady-state injectivity (the injectivity over a relatively short time) should be fairly independent of injection rate. This fact is simply a consequence of Darcy's law. The injectivity test performed at Well 1N11 in February, 2008, provides a good example (**Table 2**). Water was injected initially at 1152 BPD. The downhole pressure was 560 psi at this time and the average reservoir pressure was 200 psi. Then the injectivity was 1152/(560-200) = 3.2 BPD/psi. The rate was increased in stages up to 2304 BPD. Table 2 shows that at each rate, the injectivity was fairly constant with a value of roughly 3 BPD/psi. This result is consistent with Darcy's law and implies that no fracture is present. For the next higher rate (2448 BPD), the pressure suddenly dropped to 850 psi and injectivity increased to 3.8 BPD/psi— suggesting the formation of a fracture. As the rate was increased further, the pressure did not increase and the injectivity increased—up to 6 BPD/psi in Table 2. After fracture formation, each time the rate was increased, the fracture extended to create additional surface area to allow the increased rate to leak off into the formation without significantly increasing the pressure. Because the depth was shallow, a horizontal or "pancake" fracture formed. Stresses are such that the rock would rather push the overburden earth (above the newly formed fracture) up rather than in a horizontal direction (i.e., as happens during the formation of a vertical fracture in much deeper formations).

Table 2—Water Injectivity Test of February, 2008 in Well 1N11

Injection rate BPD	BHP psi	Injectivity BPD/psi
1152	560	3.2
1296	630	3.0
1440	690	2.9
1584	730	3.0
1728	790	2.9
1872	820	3.0
2016	900	2.9
2160	980	2.8
2304	1020	2.8
2448	850	3.8
2880	820	4.6
3168	820	5.1
3600	800	6.0
3024	780	5.2

A basic assumption in the simulation models and in the operation of the pilot was that the wells were below the parting pressure and that flow was radial away from the vertical wellbores. The downhole pressure constraint of 800 psi was based on these assumptions. The general fear when exceeding the formation parting pressure (i.e., 800 psi) is that a fracture may open and allow severe channeling of the injection fluid to a nearby production well. However, a downside of injecting below the formation parting pressure is that a substantial pressure drop occurs from the well to a short distance from the well. Thus, a lot of injection energy is wasted simply in getting the fluid into the formation—because of the dramatic pressure losses that are seen near wells that have radial flow.

However, were the injection wells in the pilot area without open fractures? Consider Injection Well 1M101 in August 2008. As shown in **Table 3**, water was injected first at a low rate (100 BPD), resulting in a downhole pressure of 553 psi and an injectivity of 0.28 BPD/psi. When the rate was raised to 650 BPD, the injectivity more than tripled to 1.01 BPD/psi — indicating that a fracture was open at the high rate. When the water rate was dropped to 125 BPD, the injectivity dropped to 0.44 BPD/psi—suggesting that the fracture closed substantially. When the rate was raised again to 650 BPD, injectivity tripled to 1.21 BPD/psi—indicating a re-opening of the fracture. Dropping the water rate again to 175 BPD dropped injectivity to 0.65 BPD/psi—indicating at least partial fracture closure. When water rate was raised a third time to 650 BPD, injectivity rose to 1.48 BPD/psi—indicating fracture re-opening. Thus, the process of opening and closing the fracture was at least partially reversible. Since this was the first time that water had been injected into this well, it seems likely that injectivity should increase with increased water injection volume—because low-viscosity water displaced some viscous oil away from the wellbore. Also, note that for this last water injection step, the downhole pressure was 638 psi—well below the accepted formation parting pressure of 800 psi—and yet the fracture was obviously open.

Table 3—Injectivity Test of August, 2008, in Well 1M101

| Injectant	Injection rate BPD	BHP psi	Injectivity BPD/psi
water	100	553	0.28
water	650	845	1.01
water	125	482	0.44
water	650	737	1.21
water	175	471	0.65
water	650	638	1.48
45-cp polymer	175	635	0.40

Finally, in Table 3, note that 45-cp polymer solution was injected at 175 BPD, resulting in a downhole pressure of 635 psi and an injectivity of 0.40 BPD/psi. Let's assume that fracture was closed during the previous water injection at 175 BPD, where injectivity was 0.65 BPD/psi. If Darcy's law is valid and no fractures are open, the expected injectivity during injection of a 45 cp fluid would be 0.65/45 = 0.0144 BPD/psi. Instead, the observed injectivity was 0.40 BPD/psi or 0.40/0.144 = 28 times higher than expected! Thus, the fracture was open during polymer injection.

A similar observation was found for the second injector, Well 1N062, in May 2010. Water was injected first at 343 BPD, resulting in a downhole pressure of 488 psi and an injectivity of 1.19 BPD/psi. When the rate was raised to 685 BPD, the downhole pressure increased to 638 psi and injectivity increased to 1.56 BPD/psi. This 31% injectivity increase might indicate fracture opening, but the point is debatable. However, when 41.5-cp polymer solution was injected at 343 BPD, the downhole pressure was 744 psi and injectivity was 0.63 BPD/psi. If no fractures were open, the expected injectivity for polymer solution should have been 1.19/41.5 = 0.029 BPD/psi. The actual polymer injectivity was 0.63/0.029 = 22 times greater than expected! So again, the fracture was open during polymer injection.

Proposed Improvement

Concept. Since the fractures are open anyway AND since no evidence of severe channeling has yet been witnessed in the pilot project, it seems pointless to worry about an artificially imposed pressure constraint that was supposed to force injection

below the formation parting pressure. Instead, we proposed taking advantage of the open fractures to (1) enhance polymer injectivity, (2) allow the polymer pressure and energy to be distributed more deeply into the formation (i.e., through the fracture), and (3) thereby increase the oil production rate. **Fig. 17** illustrates this mechanism. If polymer is injected faster or if higher polymer concentrations are used, certainly, the fracture will extend farther into the formation to accommodate the change. The key to preventing channeling will be not to allow the fracture to extend all the way to a production well. However, if a fracture does extend all the way to a producer, (1) this should be detected by a sharp increase in water cut, drop in salinity, and/or sharp increase in produced polymer, and (2) the offending fracture can be closed simply by dropping the injection rate, as evidenced by the behavior in Table 3.
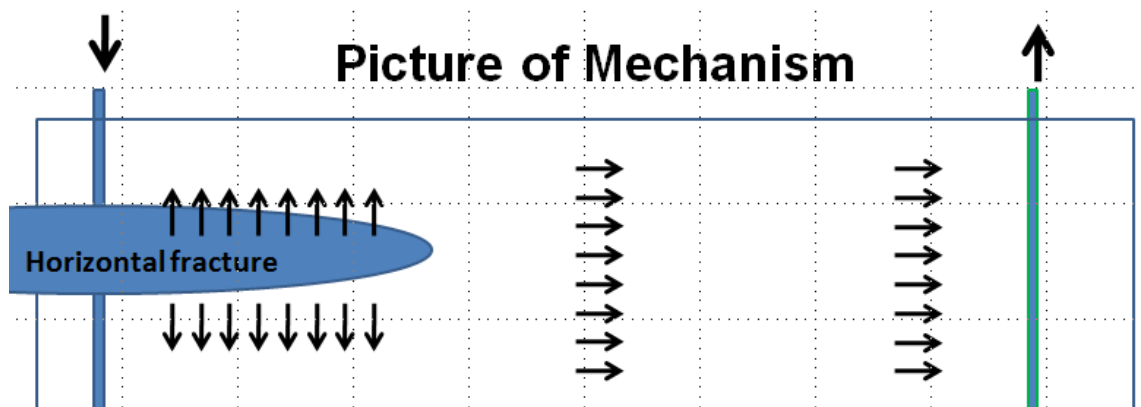
Fig. 17—Mechanism for enhancing polymer injectivity.

A side advantage of pursuing the mechanism in Fig. 17 is reduced mechanical degradation of the polymer. Mechanical degradation of HPAM depends directly on the velocity and pressure gradient experienced by the polymer (Seright *et al*. 2009). Fluid velocity is proportional to injection rate divided by flow area. For a wellbore with no open fractures, the wellbore area is $2\pi rh$. If wellbore radius is about 0.5 ft, the wellbore area at the formation is $2\pi(0.5)(12) =38$ ft^2 for Well 1M101 and $2\pi(0.5)(21)=66$ ft^2 for Well 1N062. If a horizontal fracture is created that extends 30 ft from the wellbore, the added area from the fracture is $2\pi(30^2)= 5,655$ ft^2—thus increasing the flow area by factors of 150 for Well 1M101 and 86 for Well 1N062. For a given injection rate, the increased area associated with the fracture will reduce fluid velocity (and pressure gradient) by two orders of magnitude—thus substantially reducing mechanical degradation of the polymer.

Several choices are available to implement the scheme in Fig. 17. One possibility is to keep the polymer concentration fixed but increase the injection rate. This choice allows more fluid into the reservoir in a shorter time—potentially increasing oil production rates more quickly. However, it risks greater channeling and faster breakthrough. A second choice is to keep the injection rate fixed but increase polymer concentration. This choice presents a smaller risk of channeling and rapid breakthrough, but it may not increase oil production rate over the short term. A third possibility is to increase both injection rate and polymer concentration at the same time. This choice risks confusion on determining the dominant beneficial effect.

Without detailed consideration, cost might be a possible concern if injection of higher polymer concentrations is contemplated. However, consideration of how polymer viscosities vary with polymer concentration can reduce this concern. For viscosities above 10 cp, viscosity rises roughly with the square of polymer concentration (Seright 2010). This behavior is an advantage when using polymer solutions to displace viscous oils. To explain, most previous conventional polymer floods (directed at oil viscosities less than 50 cp) used relatively low polymer concentrations (1,000 ppm or less). In this range, the relation between viscosity and polymer concentration is nearly linear, so viscosity and polymer solution cost are directly proportional to polymer concentration. In this regime, if a doubling of viscosity is desired, a doubling of polymer solution cost may be needed. For more viscous oils, higher polymer solution viscosities may be needed for efficient oil displacement. For these more viscous polymer solutions, a concentration exponent of two (i.e., $\mu \sim C^2$) means that doubling the solution viscosity can be achieved by increasing polymer concentration and cost by only 40%.

The primary risk associated with implementation of this process is that a fracture may be created that extends all the way from an injector and a producer that causes severe channeling. The behavior seen in Table 3 suggests that this problem could be largely corrected simply by reducing the polymer injection rate. However, this procedure is not guaranteed to completely shut off water/polymer channeling. It would be best if the fracture never reaches the production well. Anecdotal support from this idea comes from Well 1N11. This was the producer that was fractured during an injectivity test in 2008 (Table 2). Definitive polymer breakthrough (563-569 ppm) occurred in Well 1N11. It is possible that intentional fracture of this well contributed to the breakthrough. However, two points mitigate this concern. First, if fracturing had been a primary source of channeling, breakthrough would have occurred much earlier and more abruptly. Second, polymer broke through in Well 1N06 (316 ppm), which was not fractured. Therefore, it seems likely that the salinity and polymer breakthrough (after injecting 10+% PV of polymer solution) is the natural consequence viscous fingering. Reduction of this polymer channeling could be reduced by increasing polymer concentration.

Implementation of Higher Polymer Concentrations and Injection Rates. To test the effect of injecting more viscous solutions, the injection viscosity was raised 40 cp to a range of 80 - 100 cp—using a fixed injection rate of 206 BPD. Immediately after this change, the downhole pressure increased approximately 10% in the third injector (1M052). In the other injectors no immediate change in downhole pressure was observed. This change is less than the 50+% decrease expected if the fractures did not extend during injection of an HPAM solution with twice the original viscosity (Seright *et al*. 2009). Thus, consistent with our concept, fractures are extending to accommodate the higher polymer concentrations. The offset producers did not show an immediate response to the increased injection polymer concentration. However, this result is also expected. Some time will be required for the more viscous polymer bank to cause a noticeable reduction in producing water oil ratio.

Of course, an increase in oil production rates would highly desirable, from an economic viewpoint. The most direct method to increase oil production rates is to increase polymer injection rates. During this phase of testing, we found that increasing the polymer injection rate by 15% resulted in 6% increase in downhole pressure for the first injector, 9% in the second injector and 11% in the third injector. Again, this result is consistent with our concept that the injection-well fracture extends to accommodate the higher injection rate.

Polymer Stability

Our general expectation is that the HPAM polymer should be quite stable under the conditions experienced at the Sarah Maria pilot site. The temperature is low—only 100ºF (38ºC) in the reservoir, so no oxidative degradation is anticipated unless a redox couple is established. However, two pieces of information cause concern. The first is that dissolved oxygen levels are ambient (3-8 ppm) throughout the mixing and injection process. The second piece of information that raised concern was from a polymer backflow test that was conducted in October-November, 2009. Although the injected polymer samples had viscosities from 40-45 cp, viscosities were noticeably less for samples back-flowed from Well 1M101. Most disturbing, the polymer supplier performed an analysis indicating that the backflow samples had polymer molecular weights reduced from the original 18 million daltons to only 3 million daltons. These observations generated considerable discussion whether the results showed real degradation that would materialize in the reservoir, or whether the results were just an artifact of the testing procedures and delays in viscosity measurements.

Allowing high dissolved oxygen levels is not a good general practice. The presence of dissolved oxygen is one of the critical elements of establishing a redox couple that can seriously degrade the polymer. If dissolved oxygen is not present, then concern is lessened if the other elements get introduced. That being said, it can be argued that the high oxygen levels might be acceptable for the Sarah Maria pilot conditions. Strong support for this position comes from the experience at Daqing, where ambient levels of dissolved oxygen were also present throughout the mixing and injection process. For their case, polymer has consistently propagated entirely through the reservoir (typically 200-300 meter interwell distances of ~1 darcy loosely consolidated sand at 45ºC). Extensive analyses of the field results suggest that the average effective polymer solution viscosity in the Daqing reservoir was about 20 cp (~40-cp polymer was injected). Also, the Daqing sand (that contains ~0.25% pyrite and ~0.5% siderite) effectively removes any dissolved oxygen within one day and a short distance after the polymer enters the reservoir (Seright *et al*. 2010). A similar result is expected for Tambaredjo, since XRD analysis revealed significant amounts (up to 12%) of siderite and pyrite in some cores from Well 1M101.

The polymer mixing water that is used in the polymer pilot is very clear with low salinity (400-500 ppm TDS) and with very little dissolved iron. Polymer solution viscosities just after the mixing facility are typically and consistently ~50 cp viscosity and ~45 cp at the injection wells heads. Tests showed only modest viscosity losses over time for polymer samples (taken from the pilot mixing facility and containing ambient dissolved oxygen levels) that were in contact with iron that was characteristic of the well metal. This result is consistent with expectations. Thus, oxidative degradation was modest during normal polymer operations at the pilot project. We suspect that the degradation observed was probably dominantly a result of mechanical degradation during the testing procedures or a result of long delay (~3 months) that occurred between when the samples were collected and the molecular weight analysis that was performed (i.e., to conclude that molecular weight dropped from 18 million to 3 million). Additional analysis is needed. Nevertheless, if a substantial expansion of the polymer injection project is pursued, maintenance of near-zero dissolved oxygen levels should be considered.

Conclusions

- In the Sarah Maria pilot project, changes in the produced water salinity was an effective indicator of polymer breakthrough.
- Injection in the pilot injectors occurred above the formation parting pressure since polymer injection began. Because pressure, inter-well tracer, water cut, salinity breakthrough, and polymer breakthrough all argue against the existence of severe channeling for operations to date, injection at faster rates and/or using higher polymer concentrations could substantially increase oil production rates without risking higher-than-normal water cuts or polymer channeling.
- A specific methodology was proposed, i.e. injecting above the formation parting pressure, to test this idea within a relatively short time-frame in the existing pilot wells.

- Previous simulations predicted little improvement in displacement efficiency and oil recovery if the injected polymer viscosity is raised above 40 cp. However, in view of the mobility ratio (at least 40) and heterogeneity (permeability contrast of 10 or more), further analysis demonstrated that this conclusion is not correct. Significant improvements should be seen for polymer viscosities up to 160 cp.
- In the Sarah Maria pilot project, enhancement of the efficiency and rate of oil production is anticipated by increasing both the injection rates and polymer concentrations. These concepts are currently being tested at our project.

Nomenclature

C = polymer concentration, parts per million (ppm) [mg/L]
k_{ro} = relative permeability to oil
k_{roo} = endpoint relative permeability to oil
k_{rw} = relative permeability to water
k_{rwo} = endpoint relative permeability to water
k_1 = permeability of Layer 1, mD [μm^2]
k_2 = permeability of Layer 2, mD [μm^2]
no = oil saturation exponent in Eq. 2
nw = water saturation exponent in Eq. 1
PV = pore volumes of fluid injected
S_{or} = residual oil saturation
S_w = water saturation
S_{wr} = residual water saturation
μ = viscosity, cp [mPa-s]
$\mu_{polymer}$ = polymer solution viscosity, cp [mPa-s]
μ_{water} = water viscosity, cp [mPa-s]

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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