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Why is it so Difficult to Predict Polymer Injectivity in Chemical Oil Recovery Processes?

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Summary

Polymer injection to improve and/or accelerate oil recovery is a widespread technique with numerous ongoing and successful projects. In recent years, many field cases have been reported with injected polymer viscosity ranging from 5 to 160cP, producing large incremental oil volumes, without major injectivity issues. These field results often contradict pessimistic predictions of injectivity from prior studies. Despite abundant publications on the subject, there is no standard explanation of the reasons for discrepancies between forecast and actual behavior, and many questions are not yet fully answered. Will it be possible to inject the polymer solution at target viscosity? How much to inject? How fast? Will high pressures lead to fracturing or polymer degradation? Should the polymer solution be pre-treated, pre-sheared? What should be done if planned injection rates are not achievable? Will injectivity decline over time? These questions are very topical when it comes to building a business case for EOR, using 3D reservoir simulation models for forecasting production and calculating the economics of the project.

In this paper, we present a critical review of selected field cases from the literature, analyzing reservoir characteristics and development history as well as properties of the injected solution. We discuss the mechanisms which can affect injectivity, including polymer solution rheology, near-well flow regimes, reservoir heterogeneity and geomechanical effects, and how these mechanisms can be represented in reservoir simulation models. Based on this investigation, we propose appropriate methodologies for dynamic modeling of polymer injection, considering the impact on predicted flow behavior of assumptions about polymer physics, selection of key parameters for sensitivity studies and the issues of upscaling from core experiments to the field. We suggest guidelines for using laboratory measurements and field observations, and for implementing forecasting workflows. Finally, we make recommendations on designing a practical field injection and monitoring program, to obtain data for calibrating models and improving future predictions.

Introduction

Despite persistent low oil prices since 2014, the number of polymer flooding projects worldwide has steadily and quietly increased, often starting early in field life (as a secondary recovery technique) and lasting a year or longer, leading to larger and larger injected volumes. Many of these projects are pilots involving one or more injection wells but have not yet been published; some are in transition to sector or field development. Generally, a quick pilot phase is conducted, to gain understanding of surface and subsurface aspects of polymer injection, and enable economic assessment and risk mitigation, before moving to wider implementation. A well-designed pilot project remains critical to obtain information such as injectivity or oil recovery, which cannot be inferred directly from laboratory experiments. Pilot injection data should be used to calibrate dynamic simulation models, especially the observed injection rates and pressures, which may significantly differ from the predicted values. This aspect will be at the centre of this paper and discussion: why is it so difficult to predict injectivity in polymer injection processes?

In this paper we will discuss the different views on injectivity and what could be a definition of "an injectivity problem." Several published field cases are reviewed, with summaries of the explanations provided by the authors about the "better-than-expected" or "worse-than-expected" injectivity values. Next, the different parameters which can affect the injectivity and the ability to forecast injection performance are reviewed, including rheology, completion, reservoir-related mechanisms and simulation. This will lead us to discuss methodology for dynamic modelling of polymer flooding. Finally, we will draw a list of tools and guidelines useful to build a comprehensive monitoring program to better refine the injectivity prediction and build a more accurate business case.

What is an Injectivity Issue?

Before discussing the possible causes behind inaccurate injectivity predictions, it is necessary to attempt a definition of an injectivity issue. We can consider three scenarios, two in which there is a decrease of the injected volume into a given reservoir, compared to a previous waterflood or compared to analytical or numerical simulations and one in which the injectivity is better than forecast.

1) The injectivity decreases dramatically on commencement of polymer injection. Explanations can include poor water quality, fines migration or sanding, issues with the polymer specification or the polymer itself (e.g. inappropriate molecular weight, poor hydration, …), damaged wellbore or low reservoir permeability, unpredicted viscosity behaviour and/or change in fluid flow regime, etc. This can impair the proper deployment of the pilot or the project, requiring substantial adjustments to the injection program, remedial treatments or stimulation.
2) The injectivity decreases after a certain time. This could happen if the polymer slug mobilizes oil, forming an oil bank which is pushed toward the producers. In that case, the bottom hole pressure will slowly build up and may eventually force a decrease in injection rate depending on reservoir and facility constraints. Even if the injectivity decreases, it might still be possible to reach a higher oil production than during waterflood. An important question that arises is, "How much injectivity reduction can be tolerated while keeping the project economically viable?"
3) The injectivity barely changes or increases. This has been observed in several cases and several explanations have been brought forward, which will be discussed later in this paper. Although good injectivity is desirable, this scenario can lead to questions such as, "Is the viscosity of the polymer solution too low and what is the cause?"

Several papers have discussed the possible reasons behind injectivity decline during waterflood or polymer flood (Fletcher et al., 1992; Hsi et al., 1994; Glasbergen et al., 2015; Borazjani et al., 2018). Glasbergen et al. give an overview of the different parameters which should be considered to ensure a good injectivity and a successful polymer injection. They defined three categories which are:

- Generic reservoir flooding related mechanisms (clay swelling, scales, emulsions…);
- Anticipated mechanisms for polymer flood (polymer rheology, viscosity, retention);
- Undesired mechanisms for polymer flood (bad dissolution, improper polymer selection, infrastructures).

"How much injectivity will be lost due to the viscosity of the polymer solution?" is one of the most frequently asked questions when planning a polymer injection project. The final answer will ultimately impact the overall business case and its economics, considering the volumes of fluids that will be handled both on the injection side and the production side, as well as the effect on oil recovery over the lifetime of the flood.

Estimates of well injectivity are often based on the steady-state injectivity index, representing the degree of communication between an injecting well and the reservoir. Consider the following equation for the injectivity index II of a water injector, assuming single-phase, radial flow in a homogeneous reservoir.

$$II = \frac{Q_w}{P_i - P_d} = \frac{c\theta K_w h}{\mu_w B_w\left(\ln\left(\frac{r_d}{r_w}\right)+S\right)} \quad (1)$$

where: Q_w = injection rate; P_i = bottom-hole pressure: P_d = reservoir pressure at the edge of the well's region of influence or "drainage radius"; c is a unit-dependent constant; θ ($= 2\pi$) is the angle of connection with the well; K_w = effective permeability to water; μ_w = water viscosity; B_w= water formation volume factor; r_w and r_d are the wellbore and drainage radii respectively; h = injection height.

If the viscosity of water is increased by adding water-soluble chemicals, it can be expected that the injectivity index will decrease, with resulting reduction in flow rate and/or increase in bottom hole pressure. However, a simple model based on Darcy flow, as in Eqn 1, is not adequate to describe injectivity for a non-Newtonian polymer solution, where the viscosity depends on other variables such as shear rate.

The problem of modeling polymer injectivity has been studied over many years and methods for representing the non-Newtonian effects in reservoir simulation have been proposed and implemented (Bondor et al., 1972; Sorbie & Roberts, 1984; Sharma et al., 2010; Lotfollahi et al., 2015; Li and Delshad, 2016). Nevertheless, accurate prediction of polymer injection behavior continues to be a challenge.

Review of Field Cases

In this section, we will analyse a selection of published field cases to extract the information on injectivity and its prediction. Other field examples can be found in Sheng (2011 and 2013), Standnes & Skjevrak (2014), Delamaide et al. (2014), Seright (2016) and Al-Shakry et al. (2018).

Albania – Patos-Marinza
Hernandez et al. (2015) and Hernandez (2016) show the design and preliminary result of a larger-scale polymer flood as a secondary recovery method, applied in a heavy oil field developed with horizontal wells. Polymer solutions with viscosities from 10 to 50cP are injected into oil with viscosities of 600 to 1600 cP in over 50 wells with excellent results. Rates and viscosities are adapted by pattern and no injectivity issues or impairment were reported in the documents publicly available.

Angola – Dalia
Morel et al. (2010, 2015) summarized the results after the polymer injection test offshore Angola in the Dalia field. The authors state that this test largely fulfilled the objectives as follows:

- Injection rate of 13,000 bpd @3.3cP versus an objective of 3500 bpd;
- Injection rate of 12,000 bpd @ 5.6cP;
- Cumulative injection of 390,000 barrels above 3.3cP versus an objective of 75,000 barrels;
- No indication of plugging or injectivity loss during the polymer injection period.

Injectivity was generally above expectations. A decrease in injectivity was observed in well DAL-713 which was attributed to a poorer quality of the water injected. Mechanical degradation of the polymer was also observed in a well.

Argentina - El Corcobo Norte

Hryc et al. (2013) described the results of a 6-wells pilot in El Corcobo Norte field, in an unconsolidated formation with a live oil viscosity ranging from 160 to 300cP. Polymer was injected with viscosity between 20 – 25cP. After a short period of time, pressure started to rise in all injectors, eventually reaching an operating limit of 4700 kPa, dictated by facilities. It took an average of 8 months to reach this limit, although some variance was observed among the injection wells. Total injectivity loss at this pressure remains unclear. The oil rate stabilized and total liquid rate increased, suggesting that the production was undersupported before the start of polymer injection.

Argentina – Desfiladero Bayo

Martino et al. (2017) and Thompson et al. (2018) presented the case history of a pilot test with 6 injectors and 3 producers in the heterogeneous Rayoso formation. Initial injectivity tests were performed, with results in line with expectations. During the pilot, Hall plots were used to monitor the changes in injectivity and showed slope changes corresponding to increases in polymer concentration, with no indication of wellbore damage or plugging. Wellhead pressures at the injectors increased steadily, reaching the maximum allowable pressure, with stabilization of the water cut at producers (Figure 1). Some fracturing was expected in some intervals, and it was necessary to include this effect in the dynamic model, to match the observed injection behavior. Reservoir simulation was used successfully for planning and as a surveillance tool.

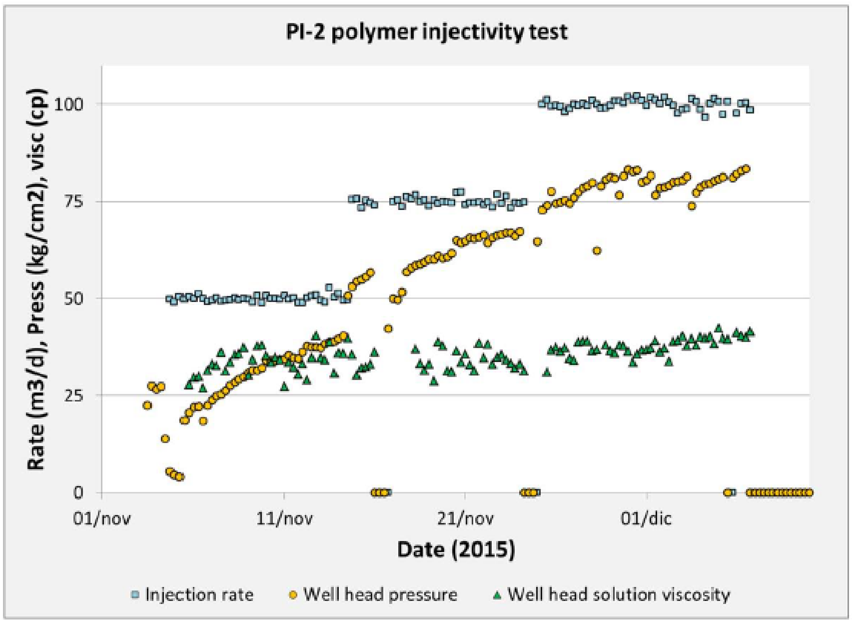

Figure 1 *Graph showing the evolution of pressure during polymer injection as injection rate is varied (Martino et al., 2017).*

Argentina – Grimbeek II

Juri et al. (2017) reported the results of a polymer injection pilot in a high permeability, multi-layered reservoir with oil viscosity 120cP. Injectors showed a decline in injectivity during waterflooding but the trend became less steep 3-4 months after polymer injection started. An incremental increase in oil recovery of around 11% OIIP was achieved in the central pattern after <0.15PV of polymer solution was injected. The overall reduction in injectivity was 20-25%. The predictivity of the simulation model was considered to be good. It was noted that reservoir velocities were < 1ft/day, corresponding to a Newtonian flow regime.

Austria – Matzen

Gumpenberger et al. (2012), Clemens et al. (2013, 2016), Zechner et al. (2014) discussed the results of the polymer injection pilot in Matzen, a mature field producing at 96% water cut. An inverted and unconfined 5-spot pattern was used for injection, with promising results. Field data showed that fracturing conditions were reached after a short period under injection. Gumpenberger et al. discussed the discrepancies in simulated wellhead pressures, which were in contradiction with field observations. To obtain a match it was necessary to include viscosity data for a sheared polymer and/or assume the creation of fractures above a certain pressure (175 bar). Zechner et al. discussed a 2-step simulation approach for injection under matrix conditions and then fracturing conditions. The calibrated model was also used to investigate the impact of polymer rheology and particle plugging on injectivity and resulting fracture growth. It highlights the importance of understanding near-wellbore petrophysical and geomechanical characteristics and also the need for water treatment to obtain appropriate water quality and minimize plugging risks.

Canada – Medicine Hat

In the Medicine Hat, Glauconitic C Pool in Alberta, reviewed by Batonyi et al. (2016)., the original pilot started in 2012 with 5 injection wells, targeting 1000 m3/d (~200 m3/d/well), attempting to increase the recovery efficiency. The core objective was to achieve a response time in one year and ultimately a 6 %OOIP incremental recovery over the waterflood baseline; however, after only 4 months, oil rates and oil cuts started to increase unexpectedly. The initial response was most likely from the "stripping" of oil layers along previously formed water channels, leading to potentially early polymer breakthrough – which in the case for the Medicine Hat field, was on the order of 48 hours and in some cases in shorter time frames than this. Through active reservoir management, careful monitoring of injection patterns and implementation of conformance treatments, this field has expanded to include up to 100 total injectors, with steady injection averaging 130 m3/d/well. The pilot areas, averaging injection of 112 m3/d/well during early waterflood, reached a peak of ~170 m3/d/well by 2015. Rates were reduced just prior to 2016 where either reservoir fill-up and pressure constraints were encountered, or to curtail injection channelling.

The pilot area saw a pre-polymer, oil rate of 130 m^3/d (@ 7.4% oil cut), with a response up to 300 m3/d and 15% oil cut, several months later. As well count increased through to 2014, a new peak of just over 360 m^3/d was achieved, with a stable oil cut averaging ~9%, with oil decline having started by mid-2016. Due to quick breakthrough in existing water channels, polymer injection best performs when considered as secondary recovery method.

Canada – Pelican Lake

The Pelican Lake field in Northern Alberta, has been under polymer flood for several years and underwent a systematic approval process for different areas of the field, to obtain authority to inject at higher and higher pressures, through step rate and cap rock testing to confirm reservoir parting pressure containment. Due to the shallow depth of the Wabiskaw reservoir, initial reservoir pressure was estimated to range between 1900 and 2600 kPa, based on pressure gradients from gas wells in the pool (Alberta Energy Regulator, CNRL Report 2010). The original Horsetail Pilot location comprised of two horizontal injectors and three horizontal producers (Government of Alberta, IETP Annual Report, 2007). It required nearly 8 months to achieve fill-up after a brief primary production period, reaching a maximum injection pressure of ~6,500 kPa, before injection rates were adjusted downward from 300 m3/d (150 m3/d/well) to 200 m3/d (100 m3/d/well). Production response lagged with injection until fill-up was achieved, but eventually spiked to over 60 m3/d for the three producers at a fairly stable water-cut of 20%. The production trend continued through most of the production life of this pad, with a declining oil rate; however, water-cut has still only increased to 70%. These early pilots paved the way for the operator to adopt more polymer flood expansions with polymer applied as a secondary recovery process, foregoing waterflood after primary.

Canada – Suffield Caen Field

In the Suffield Caen field, waterflooding of the 17°API, ~100 cP (400-600 cP dead oil) medium-heavy oil had been ongoing since 1996, but water-cuts were approaching 96% despite only achieving a recovery of 20 %OOIP. Liu et al. (2012) identified unfavorable mobility ratio and poor sweep efficiency and discussed the original 2-injector pilot area to be evaluated for polymer flood. The pilot project commenced in 2010. No injectivity issues or early polymer breakthrough were reported over the 15+

months that were reported in the paper. The two offset producer wells, with interwell distances of 100 m and 300 m, showed response times of 5 and 8 months, respectively, with peak oil rates approaching 20 m^3/d (up from ~4 m^3/d). There were modest reductions (~10%) in water-cut, while the best responding well showed a broad incremental oil peak hitting 25 m^3/d and a reduction from 87% water-cut, down to 50-60% for nearly a year and a half after the initial response time. Many larger fields in the Suffield area also have EOR potential, with similar properties to the Caen reservoir.

Colombia – Palogrande Cebu

Pérez et al. (2017) detail the results of polymer injection in the Palogrande Cebu field which started in May 2015. As of December 2016, cumulative incremental oil production exceeded 85,000 barrels with a 10% decrease in water-cut. Treatments were used in injection wells (e.g. sodium hypochlorite) to improve injectivity. Injection rates and polymer concentration were modified throughout the project, to avoid exceeding the operating pressure limit. The initial results were considered successful and operating company plans to expand the polymer injection in 11 patterns.

Egypt – Belayim

Lazzarotti et al. (2017), Spagnuolo et al. (2017) and De Simoni et al. (2018) shared the first results and design workflow of a polymer injection pilot performed in Egypt. In February 2016, after an initial ramp-up period, polymer injection started at 1000 bbl/day with a viscosity of 5cP at reservoir conditions. The authors report an "unexpectedly high well injectivity" and, later, a decrease of injectivity only by a factor of 2 following a tenfold increase in viscosity (Figure 2). Two possible explanations were brought forward: 1) mechanical degradation of the polymer or 2) injection under fracturing conditions. Well tests confirmed the existence of microfractures. Results were integrated in a radial simulation model where the simulated BHP also exceeded the actual data gathered during the injection. To better match the pressure response, a progressive transmissibility improvement was implemented in the model in the near-wellbore zone to simulate the development of microfractures.

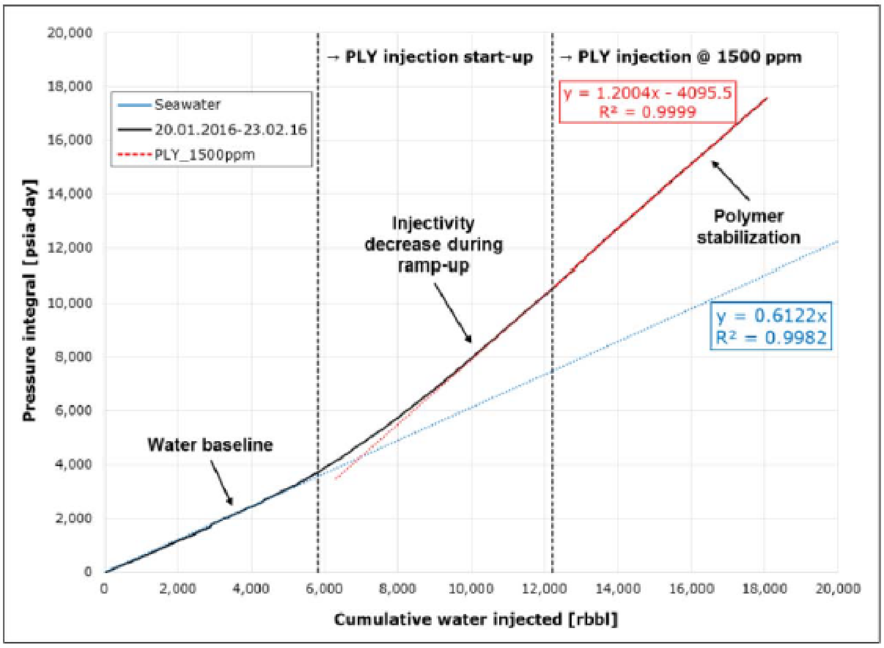

Figure 2 *Hall plot from the polymer injection start-up. A clear change of slope can be observed but with a rapid stabilization and good injectivity (Spagnuolo et al., 2017).*

India – Baghyam

Shankar et al. (2018) summarize the results of several polymer injectivity tests carried out in the Baghyam field. The first trial was performed from August 2014 to May 2015 in two wells. In the first well, water injectivity was zero and a stimulation campaign was performed allowing an injection rate of 2000 bbl/day @500psi instead of the 4000bbl/day expected. Subsequently, injectivity during polymer

injection was poorer than expected. Above 600psi, injectivity increased and fracturing was suspected. In the second well, water injectivity was in line with expectations and no injectivity issue was observed during polymer injection with a viscosity of 20cP.
A second test commenced in October 2016 in another area of the field. The combined injectivity expectations for the four wells in this zone was 5000bbl/day and finally reached 10,000bbl/day of polymer solution. Oil response amongst the offset producers was excellent, as a result of the improved flooding support. The authors also noted that the loss of injectivity at higher viscosity appeared to be less than predicted by a perfectly shear-thinning rheological fluid model. A reduction of the injectivity index of 10% was observed when viscosity was increased from 20 to 30cP. Field observations could be matched to the model by reduction of skin factors when viscosity was increased.

India - Mangala
Kumar et al. (2012) detail injectivity tests performed in the Mangala oilfield. Polymer injection followed a 0.5PV water injection in a 100x100m five-spot pattern with vertical wells. A comprehensive field monitoring program including PLT, downhole pressure monitoring, tracer surveys, saturation changes, water composition changes and fluid cuts was put in place to follow field response. Some injectivity decline was observed due to poor water quality and injection temperature below wax appearance temperature. An injectivity restoration program was launched before polymer injection. No issue was observed during the polymer injection test at 20 – 30cP: pressure data were collected for water and polymer, but not for comparable injection rates. The injection process was simulated using a radial model: the authors state that the calculated pressure was much higher than the actual measured data, unless a shear-thinning option was used in their models.

Kazakhstan – Kalamkas
Sagyndikov et al. (2018) detail the implementation of a pilot with two vertical injection wells in Kalamkas oilfield, as a tertiary method. A 20 – 25cP polymer solution has been injected since 2014 leading to an 8.2% decrease in water-cut so far and a utility factor of 76 tons of oil per ton of polymer injected. No injectivity issues have been reported, with pressure in the wells either stable or gradually increasing along with the injected volume (Figure 3).

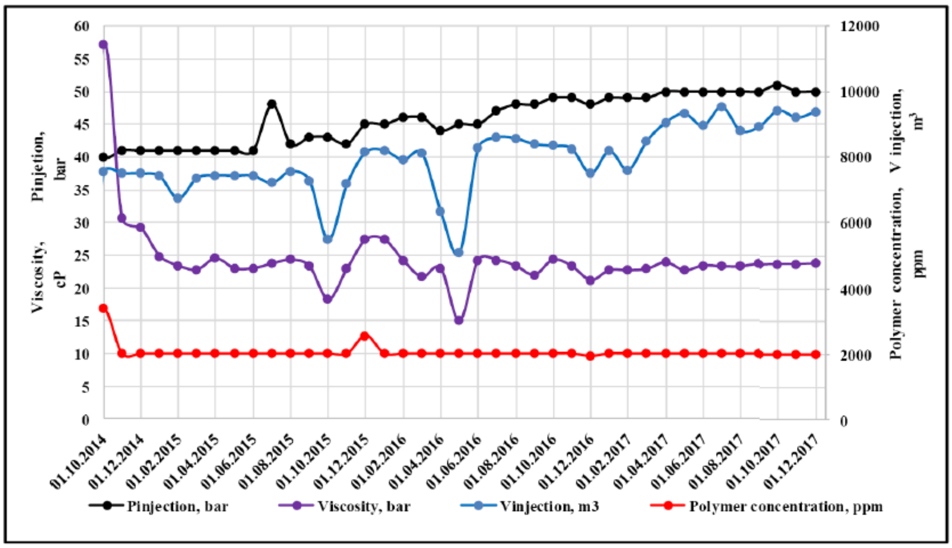

Figure 3 *Evolution of pressure in one injection well for the Kazakh project. A continuous and gentle increase can be observed over 2 years before stabilization (Sagyndikov et al., 2018).*

Oman – Marmul
Al-Saadi et al. (2012) discussed the first results of the polymer injection project in Marmul, Oman. They noted that the injection pressure data over a period of 2 years from the start of polymer injection were lower than that calculated for the designed polymer viscosity. They proposed a list of mechanisms to explain this observation:

- Injection under fracturing conditions
- Shear degradation. This was disproven later by analysis of the effluents.
- Polymer rheology: shear-thinning, shear-thickening
- Clean-up of injectors, decreased skin
- Dilution (also during radial flow)
- Local and uncharacterized heterogeneities.

Thakuria et al (2013) confirmed that most wells were injecting under controlled fracturing conditions, explaining the better-than-expected injectivity.

Russia – East Messoyakha
Zagrebelnyy et al. (2018) detail the implementation of a 2-well (horizontal) pilot in the Messoyakha field, in an unconsolidated formation with medium-heavy oil (111cP). A polymer solution with a surface viscosity of 30cP was injected following a very short water injection period. The injection rates and viscosity were ramped-up but pressure did not rise quickly during the first 10 days. After reaching the final injection rate of 300 m^3/day, required to achieve a VRR of 1, pressure started to rise slowly with a trend towards stabilization. The Hall plots also showed a trend towards stabilization after several weeks. The production plots show higher stabilized oil rates than during primary production. The water-cut shows only a slight increase, in the presence of an active aquifer – this trend started before any fluid injection in the field. The results from the pilot were used for history matching with a focus on the adsorption parameters of the polymers. To reduce remaining uncertainties, it was decided to continue the pilot up to 10% of reservoir pore volume.

Russia – West Salym
Van der Heyden et al. (2017) and Volotikin et al. (2017) detail the results of the ASP pilot conducted in the Salym field in Russia, in sands with permeabilities of 10-150 mD and oil viscosity around 2 cP. During the first part of the project, water injectivity appeared to be very poor and, after several remediation attempts, it was decided to fracture the formation, while controlling the propagation to avoid impairing pattern containment and potential reservoir sweep.

Conclusions are that water compatibility and treatment options should be reviewed to ensure these will not impact potential pilot operations. Use of an in-house semi-analytical fracture simulator for a sensitivity study of induced fracturing provided guidance for designing the stimulation treatment.

Suriname – Tambaredjo
Moe Soe Let et al. (2012) and Wang et al. (2017) discussed the mechanisms involved in the Tambaredjo oilfield in Suriname where polymer injection has been performed with success. Polymer viscosities ranging from 40 to 160cP were injected to displace a 500cP oil without any major injectivity issues. Moe Soe Let et al. demonstrate the existence of fractures in the field which greatly help the injection of viscous polymer solutions while minimizing degradation effects. The authors also note that two assumptions had to be reviewed in the model: 1) the flow is radial away from the vertical wellbore and 2) the injection occurred below the parting pressure. Modeling investigations included review of the bottom hole pressure constraint and flow regime around the wellbore.

UK – Captain
Poulsen et al. (2018) summarized the result of the pilot injection in one well in the Captain oil field offshore UK. A polymer solution with a viscosity of 20cP was injected into the C43 well from October 2009 to August 2013. The authors cited several benefits including 1) a decrease in water-cut, amounting to more than 25 million barrels of water saved compared to the baseline, 2) a 16% increase in recovery factor and 3) an acceleration of production compared to the baseline. The initial injectivity test showed no limitations over the tested rates and polymer concentrations, even with injection of 200cP polymer solution. However, the injection pressures increased during the continuous pilot injection, until the BHP exceeded original predictions. Based on this experience, the authors developed an analytic tool which was calibrated against the pilot injector to predict the behavior of future wells.

Summary of field cases

Table 1 below summarizes the field cases discussed in the previous paragraphs. It should be noted that no dramatic injectivity decrease was reported at the start of polymer injection except when water injectivity was already poor. In most cases, it appears that injection occurred under fracturing conditions or was better than simulated. In other cases, for heavy oil, unconsolidated sands, injectivity can be better than expected due to sand dilation, movement and production. Model changes used to match the actual field results included:

- Development of new analytic tools;
- Change of well skin;
- Increased transmissibility/permeability in the near-wellbore area;
- Model fracture creation and propagation;
- Change BHP;
- Modify the keywords for polymer (adsorption, shear-thinning).

Field	Short-term injectivity issue?	Explanation for injectivity	Modeling tool / solution
Albania – Patos-Marinza	No	-	-
Angola – Dalia	No initial problems, but later sudden decrease in one well	Poor water quality	Reservoir simulation
Argentina – Desfiladero Bayo	No – continuous pressure increase	-	Reservoir simulation
Argentina - El Corcobo Norte	No/Uncertain	Pressure limited by facilities	Simulation at lab and field scale
Argentina – Grimbeek II	No	-	Reservoir simulation
Austria – Matzen	No	Fractures at high pressure/rate	Model for fractures/fine migration and polymer rheology
Canada – Medicine Hat	No	-	
Canada – Pelican Lake	No	Sand / dilation movement	
Canada – Suffield Caen	No	-	
Colombia – Palogrande Cebu	No	-	EOR screening, reservoir simulation
Egypt – Belayim	No	Fractures	Refinement of near-wellbore zone with increased transmissibility
India – Baghyam	No	-	Decrease of well skin to match field data
India – Mangala	No	-	Radial model with shear-thinning keyword for matching
Kazakhstan – Kalamkas	No	-	Analytic methods
Oman – Marmul	No	Fractures	Reservoir simulation
Russia – East Messoyakha	No	-	Adsorption used as tool to match response
Russia – West Salym	Yes with water, no after fracturing	Controlled fracturing	In-house analytical fracturing model
Suriname – Tambaredjo	No	Fractures	Review of BHP constraints and flow regime
UK – Captain	No	-	Development of analytical tool to match pressure response

Table 1 *Summary of field experience.*

Mechanisms Affecting Injectivity

Here we will assume that the generic reservoir flooding mechanisms have been properly covered and de-risked, that the polymer has been properly selected and tested and that the related injection facilities allow a good dissolution, hydration and injection of the solution. Therefore, we will consider three categories that should be investigated to avoid underestimating the injectivity and project feasibility. These categories are:

- Polymer-related mechanisms: rheology, degradation, drag reduction
- Reservoir-related mechanisms, including near-wellbore flow regime, conformance, fractures, dilation, voidage replacement ratio, heterogeneity, etc.
- Reservoir simulation studies: modeling assumptions and data quality

Polymer-related mechanisms. Polymer solutions behave as non-Newtonian fluids (pseudo-plastic), where at low shear rates the viscosity decreases as the shear rate increases, following a power law relationship (Figure 4). Up to a certain value of shear rate, the process is reversible i.e. the viscosity will return to its original value at low shear. This shear-thinning behaviour can be observed both in rheometers and inside a core. We will differentiate between these in the coming sections.

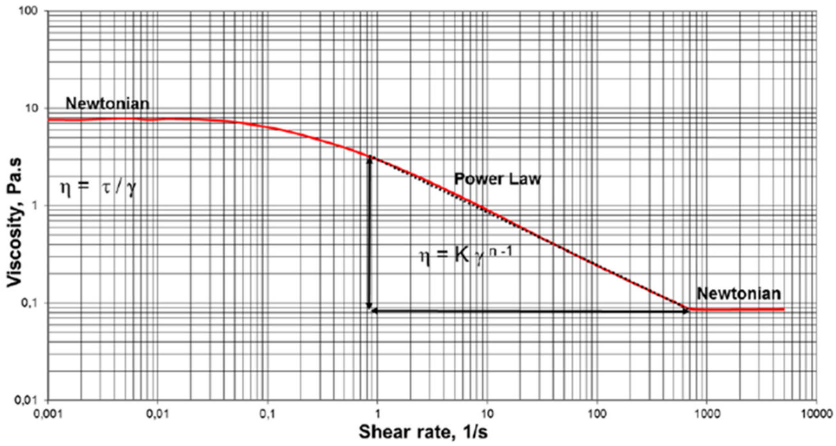

Figure 4 *Typical rheological curve for a polyacrylamide solution. At low end shear rate, two Newtonian plateaus are observed with a conventional rheometer.*

Shear-thinning. In the industry, the target viscosity for polymer injection is usually determined at a base shear rate of 7.34 s^{-1} using a Brookfield rheometer with a UL module spinning at 6 rpm (Thomas, 2016). With rheological curves, it is possible to account for the viscosity changes at different shear rates derived from the velocities in the surface installations or in the well (which can be significant), but it is not possible to predict the corresponding pressure drop that will impact design and injectivity calculations, especially the bottom hole pressure during flow. The latter is defined as:

Bottom Hole Pressure (BHP) = Hydrostatic Pressure (HP) + Surface Pressure (SP) + Frictional Pressure (FrP)

When polymer injection is started, in addition to the viscosity of the solution changing with shear (Figure 5), we will also observe a decrease in the frictional pressure drop because of the drag reduction effect.

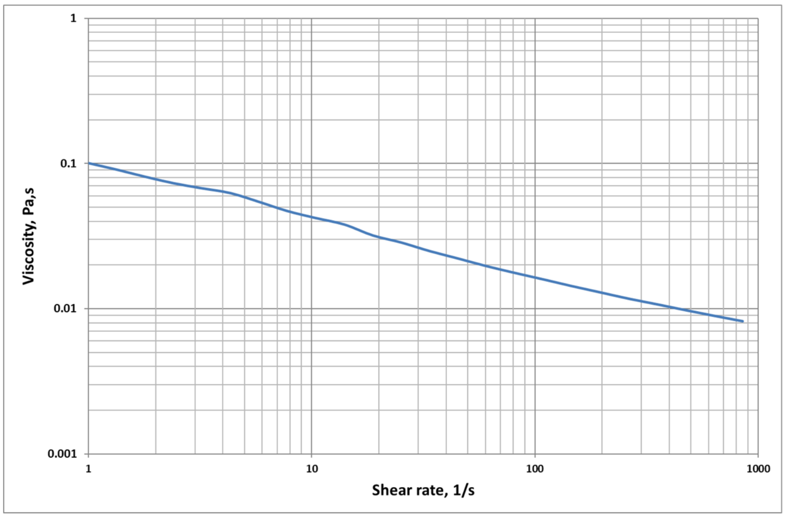

Figure 5 *Flow curve of Flopaam 3630 S in 10 g/L NaCl brine at 25°C. Note the difference between the viscosity at low shear and high shear rate which is 1 order of magnitude in this case.*

Shear-thickening. This phenomenon occurs when polymer molecules are forced at high shear rates through a porous matrix, where the time for polymer relaxation exceeds the transit time from pore throat to pore throat, increasing the extensional viscosity and leading to a significant increase in resistance factor. If the shear rate is too high, mechanical degradation occurs, cutting the molecule's length/molecular weight and the resistance factors can be decreased further (Seright et al., 1981; Seright, 1983).

Shear-thickening is often studied in laboratories, since it could greatly impact polymer injectivity under matrix conditions. However, it is uncertain whether injection really occurs under "pure" matrix conditions. As discussed in the review of field cases in this paper, it appears that many injection processes are carried out under fracturing conditions, especially with vertical well developments. If fractures or microfractures exist, then the transmissibility for polymer flow from the well into the reservoir will be greatly improved. As the shear rate decreases very rapidly away from the wellbore, the conditions required for shear-thickening may not occur in the field.

Are the polymer solutions prepared in the laboratory and injected in the field comparable? In the laboratory, polymer solutions are often prepared under pristine conditions to minimize any undesired polymer degradation. Sometimes they are also over filtered. However, in the field, the diluted solution will be subjected to shear during its transport. During that period from the surface down to the reservoir, the longer polymer molecules which are also the most sensitive to shear will be degraded first, with little change to viscosity. However, these molecules are the ones contributing the most to the shear-thickening effect (Buchholz et al., 2004). A test was conducted with Flopaam 3630S comparing the viscosity and screen factor of polymer solutions before and after passing a coil (pressure drop of 1 bar): the viscosity measured before and after the coil were 17.7 and 17.2 cP, respectively (25°C, 7.34s^{-1}), therefore little degradation took place. As for screen factors, the values were 68.2 and 24.4 before and after the coils, respectively. Although very little viscosity loss was observed, a significant change in screen factor indicated that larger molecules were impacted. Another example is given in Figure 6. Polymers from the same family but with different molecular weights (to simulate degraded polymers) were injected in cores with similar characteristics. The results show that the onset and amplitude of shear-thickening varies significantly although the injected viscosities are the same. This suggests it is highly possible that the impact of shear-thickening with fresh polymer solutions will be overestimated. On a side note, for low permeability reservoirs, it is not uncommon to pre-shear the polymer solution to maximize its penetration into the rock (Driver et al., 2018; Jouenne et al., 2015): this can lead to lower resistance factors but also a deterioration of viscoelastic properties (Maerker, 1975; Dupas et al., 2013; Tahir et al., 2017).

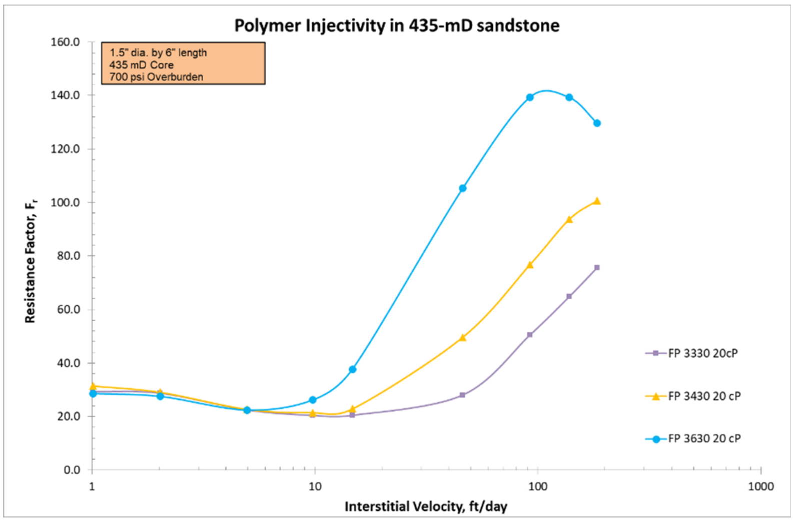

Figure 6 *In-situ rheology of 3 different polymers injected at the same viscosity. Flopaam 3330S, 3430S and 3630S (from medium to high molecular weight). The onset and amplitude of shear-thickening are earlier and higher for the high molecular weight product FP3630S compared to FP3430S and FP3330S.*

A possible approach could be to compare viscosity, filter ratio and screen factor values along with core floods for fresh and slightly degraded polymer solutions considering the effects on parameters such as shear-thickening, viscoelasticity, resistance and residual resistance factors (an example is given in Sorbie & Roberts, 1984). The final objective is to get as close as possible to field conditions, to avoid overestimating shear-thickening effects.

Drag reduction. Initially described by Toms in 1948, the drag reduction or friction reduction effect provided by several chemical components including polymers is today well-known and applied in several industries. The largest application today is hydraulic fracturing: small amounts of polymer (from 50 to 300 ppm) are added to the fracturing fluid to decrease the friction during pumping. What is less well-known is that friction reduction also plays a role at higher polymer concentration and viscosity when the fluid enters the turbulent regime (Reynolds number above 3000). It means that, for the same flow rate, in turbulent regime, the pressure drop measured during the flow of polymer solution can be 70% less than the pressure drop during the flow of water. If the pressure gradient is fixed, then the injection rate will be higher for polymer than for water. Figures 7 and 8 are examples of drag reduction profiles for small pipes (1/2-inch, 1 inch ¼ and 2 inches) and larger pipes (4 inches): in all cases, in a turbulent regime, with a 15cP polymer solution, the pressure drop can be up to 60% lower than for water, whatever the pipe diameter.

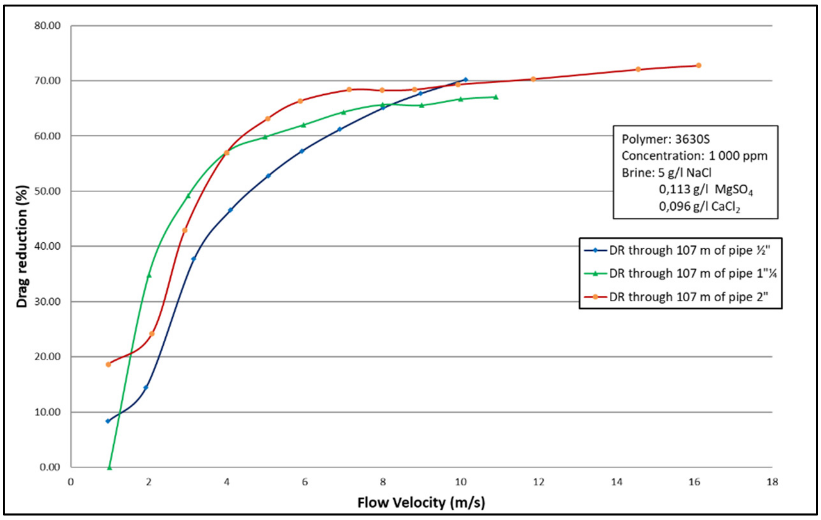

***Figure** 7 Drag reduction (%) versus flow velocity through 3 pipes with different diameters (1/2", 1"1/4 and 2") and a length of 107 meters. Polymer solution: Flopaam 3630S @1000ppm (15cP@7,34s^{-1} and 20°C). Drag reduction occurs at velocities above 1 m/s and plateaus between 60% and 70% at high velocity.*

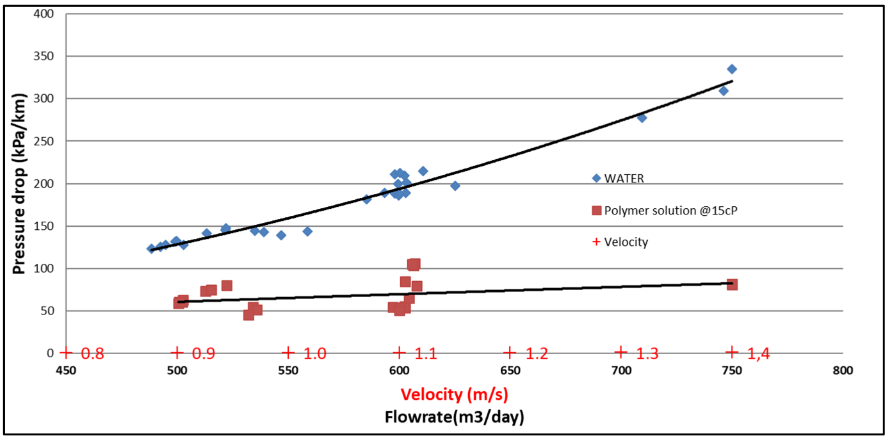

***Figure 8** Pressure drop of water and polymer solution (FP 3630S - 15cP @7,34s^{-1}) versus flow rate and fluid velocities in a 4 inches diameter pipe over several kilometres.*

If we consider the start-up of a polymer injection pilot or injectivity test, if the flow in the well is turbulent, the injectivity index can be affected in scenarios such as the following:

- If the field is waterflooded, the water injection rate is taken as a baseline and the polymer concentration is ramped-up, then the friction pressure (FrP) will decrease.
- If the injection rate is ramped-up at fixed polymer viscosity, the apparent viscosity will progressively decrease, and the turbulence will also be dampened.

The examples shown here indicate that drag reduction can have a significant effect on wellbore hydraulics and should be considered in analysis of the performance vertical and horizontal injectors as well as surface pipelines.

Reservoir-related mechanisms. A good reservoir description is obviously required to make reliable assumptions and calculations but, in the end, understanding what happens in the near-wellbore area is probably the most important aspect when attempting an injectivity forecast. Some of the important factors are listed and detailed below.

Fractures. As discussed in the previous paragraph, the existence of fractures or microfractures is probably the main reason behind the good injectivity values observed during the majority of polymer injection projects. A good example is given by Wang et al. (2011): in the Daqing oilfield, the injectivity

of polymer solution with viscosities between 150 and 300cP was only 10% lower than for a 50cP solution. The existence of fracture-like features is especially true for consolidated formations developed with cased and perforated vertical wells. Several authors have discussed fracture creation and extension (Moe Loe Set, et al., 2012; Thakuria et al., 2013; Manichand et al., 2013; Clemens et al., 2013; Manichand & Seright, 2014; Zechner et al., 2015; Seright, 2016). These studies show also that injecting under controlled fracturing conditions is beneficial for injectivity and for the polymer itself since it can limit the singular pressure drop and therefore mechanical degradation (see also Van der Heyden et al., 2017). Obviously, it is necessary to ensure that the creation and propagation of such features will not compromise reservoir containment or connect an injector with a producer; Seright (2016) has given insights on this particular matter.
For the specific case of unconsolidated formations developed with horizontal wells, several authors studied the creation of fractures and matrix dilation (permeability enhancement) (Zhou et al., 2010; Zitha et al., 2015). In their study, Zhou et al. showed that the injection of a viscous solution created multiple and complex fracture networks and increased the permeability by 40% due to shear dilation. This might be another parameter behind the better-than-expected injectivity of the viscous solution observed for such reservoirs. A similar study was conducted by Wang et al. (2017)

Dilation and fracture creation/propagation are dynamic processes (Gadde and Sharma, 2001, Seright et al., 2009; Clemens et al., 2013; Seright, 2016). As an oil bank is mobilized, it is likely that fracture growth or matrix dilation will accommodate the pressure build-up. Moreover, if shear-thickening occurs, the pressure build-up will likely force the creation of new preferential paths, including fresh fractures. The fracture creation process requires “energy” and is also competing with fluid leak-off in the matrix. Understanding the geomechanics in the near-wellbore zone will therefore help refine the model and the grid in that part of the reservoir. Moreover, since it is an evolving process, periodic adjustments will be needed during history matching. Hall plots (Buell et al., 1990), micro seismic, step rate tests, etc. are useful tools which can be combined to characterize the presence of fractures and fine-tune the injectivity forecasts as well as the 3D model.

Geological uncertainty. If uncharacterized heterogeneities are present (large fractures, high or low permeability zones) or if a direct and unknown connection exist which drives the fluids out of the pattern, it is possible that no change in injectivity will be observed. If these features do exist, were evolved from the onset of waterflood and connect to offset producers – through high perm layers in a vertical well or viscous fingering channels along the lateral section in a horizontal – these features may take the majority of the injected water. In this case, the injectivity obtained during waterflood and the rate required is perhaps grossly overestimated and more dictated by the voidage remaining from primary production. Then, when viscous polymer is injected, and vertical sweep and/or effective wellbore length are improved, injectivity and the rate of polymer injection are lower, as they are more reflective of the pressure required to push viscous polymer into more reservoir volume and to displace more oil. This can be de-risked by performing tracer campaigns upfront or by carefully analyzing well connectivity and reservoir response over the years, if applicable.

Voidage replacement ratio (VRR). In many polymer injection projects, pressure is taken as a success criterion to prove the efficiency of the process. However, if the voidage replacement ratio (the ratio of reservoir barrels of injected fluid to reservoir barrels of produced fluid) is largely below 1 (or if fractures are present or if the reservoir has been greatly depleted), building up pressure might take a very long time and reservoir oil response can lag behind what might be expected. In addition to precisely defining the pattern boundaries, it is necessary to balance injection and production throughout the field when possible to decrease uncertainties but also minimize excessive fingering and delay chemical breakthrough for as long as possible. This is especially important in horizontals where weak points along the horizontal and close-proximity well spacing may lead to very early breakthrough and could potentially disrupt the project without some reservoir intervention.

Methodologies for Dynamic Modelling of Polymer Flooding

Answering the question "why is the injectivity often much better than expected?" requires a step back to understand how the expectations were built. Usually it is via 3D modelling and simulation when designing a business case to determine the oil recovery efficiency and calculate the economics. What are the main parameters in the model which can explain such discrepancies between the field cases and the predictions?

Reservoir model. Numerical simulators generally use a multi-phase extension of Darcy's Law to model fluid flows in reservoirs. Models can be built at the scale of a coreflood, a single-well model, a sector or a full field, discretized on 3D grids. Development of a fit-for-purpose model usually requires a compromise between accuracy and speed, depending on factors such as reservoir structure, heterogeneity, well spacing and the level of detail needed to model fluid behaviour accurately.

The problems of grid resolution and upscaling have been debated in the industry for many years. For EOR, the assumptions of Darcy flow do not always apply and there are additional challenges to represent physical and chemical processes which occur on different time and length scales (Moreno et al, 2011, 2013 and 2015). As an illustration, Figure 9 shows the different polymer concentrations obtained for different grid resolutions in a simple reservoir simulation model: this will affect all polymer properties that are a function of concentration. Recent work on upscaling for polymer flooding includes an example of grid refinement and the impact on the prediction of polymer propagation in the reservoir (Najafabadi and Chawathe, 2016) and a proposed methodology for upscaling for polymer flooding (Al-Dhuwaihi et al., 2018).

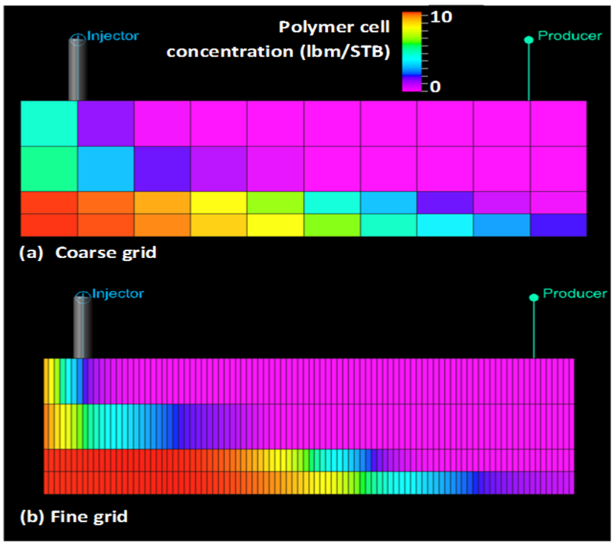

Figure 9 *Comparison of polymer concentration in coarse and fine grids (Shotton et al., 2016).*

Properties of aqueous polymer solutions. Polymer models in commercial reservoir simulators generally assume that the polymer components exist only in the aqueous phase. Properties of that phase depend on the concentration of polymer and the salinity of the water, as well as other variables such as pressure, temperature and shear rate. The calculated values for concentration are likely to be affected by numerical dispersion in coarse grids. It is also necessary to consider viscous fingering effects, for example when a slug of polymer is overtaken by less viscous chase water. In a coarse grid cell, the effective properties of the aqueous phase depend on the degree of mixing between the polymer solution and the brine (Bondor et al., 1972; Luo et al., 2017).

The effects of polymer rheology are represented by using empirical methods to calculate the apparent viscosity of the aqueous phase. For example, non-Newtonian shear-thinning behaviour can be modeled using the Meter equation to obtain the apparent viscosity as a function of shear rate (Meter and Bird, 1964; Li and Delshad, 2014).

$$\mu_p = \mu_w + \frac{\mu_p^0 - \mu_w}{1 + \left(\frac{\dot{\gamma}}{\dot{\gamma}_{1/2}}\right)^{P_\alpha - 1}} \tag{2}$$

where: μ_p is the apparent viscosity of the aqueous polymer solution; μ_p^0 is the viscosity of the aqueous polymer solution at zero shear rate; μ_w is the viscosity of water with no polymer; $\dot{\gamma}$ is the shear rate; $\dot{\gamma}_{1/2}$ is the shear rate at which the apparent viscosity is an average of μ_p^0 and μ_w; P_α is an empirical coefficient.

The shear rate in Eqn, (2) can be calculated as follows.

$$\dot{\gamma} = \frac{\dot{\gamma}_c |u_w|}{\sqrt{K k_{rw} \phi S_w}} \tag{3}$$

where: $\dot{\gamma}_c$ is an empirical coefficient; $|u_w|$ is the norm of the Darcy velocity of the aqueous phase in a grid cell; K is the average permeability in a grid cell; k_{rw} is the relative permeability of water; ϕ is porosity; S_w is the aqueous phase saturation.

The shear rate depends on the phase velocity calculated in the simulator, which depends on grid cell geometry, reservoir properties and flow rates. It is sensitive to model discretization in length and time. The impact of non-Newtonian effects is likely to be greatest near injection wells where high flow rates occur, whereas the flow rates in the reservoir are relatively low. Maximum shear rates occur close to the wellbore and may only be captured in a fine radial grid.

Note that the apparent viscosity μ_p corresponds to the in-situ viscosity of a polymer solution, which may differ from the viscosity measured with a rheometer. The parameters chosen for simulation purposes should be derived from core floods as much as possible.

Well model. The standard connectivity index calculations used in commercial simulators are based on Darcy flow assumptions (Peaceman, 1983) that are not necessarily valid for polymer injection. This problem may be addressed in an ad-hoc way by adjusting the skin factor of the well to match observations. Li and Delshad (2014) described an analytical injectivity model that can be used to modify the injectivity in reservoir simulation. Poulsen et al. (2017), in their paper on the Captain polymer pilot, propose an equation which was calibrated with field data to enable more accurate prediction of pressure in the injection wells. Although there has been progress on this topic, the methodology is still evolving.

Design of Injection and Monitoring Program

In this section, we will summarize a list of monitoring tools which should help better understand the relevant parameters affecting injectivity prediction.

For any pilot or field test, it is necessary first to define the objectives and put in place the injection and monitoring program required to validate the technology. For polymer flooding, as for other EOR technologies, we can divide a pilot into 3 stages: 1) selection, characterization and design of the pattern and wells, 2) injection program (target polymer, viscosity, rate) and start-up (process and equipment commission), and 3) continuous injection and monitoring. Here we will summarize the most important parameters. More examples can be found in the papers cited in the review of field cases.

Selection and preparation of pattern and wells.
There are several important aspects to consider before starting a pilot. Examples of checklists are given below.

For patterns.

- Select a zone representative of the whole reservoir, if applicable, in terms of well type, spacing, completion, geology, permeability, production history. The use of statistics is a good tool to target the most appropriate zone(s);
- Define, as precisely as possible, the direct communication and the boundaries of the patterns using interwell tracers and injection well tests. A confined injection pattern is always preferred. This will also be important for the modelling part;
- Check the connectivity between the wells inside the pattern;
- Establish a steady baseline if water injection is already on-going: steady rates, pressures and if possible liquid rates. Similarly, producers should be kept at consistent fluid levels and BHP such that the voidage replacement ratio can be close to one in order to limit the impact of other mechanisms on production (compaction, gas drive, etc…). In some heavy oil waterfloods, this may not be possible due to depletion, sand production, channelling etc.
- Analyse the field stresses and geomechanics if fracturing is necessary under a controlled manner or if it is occurring due to factors discussed prior (rheology, water quality etc.).

For wells.

- Well completion should be clean and functional;
- In the case of perforated wells, the number of perforations should be adequate in number, diameter and depth to minimize degradation of the polymer;
- The connection between the well and reservoir should be analysed: what is the flow regime? Presence of fractures? Local heterogeneities? Possible dilation/decompaction? Geomechanics and stress changes?
- Well tests should be performed to define the reservoir conditions and limits:
    - Step rate test for fracturing;
    - Production Logging Tool (PLT), Temperature logs or sonic logs for flow dynamics near-wellbore;
    - Micro-seismic to determine the changes at the start of polymer injection
    - Saturation logs, especially for SP and ASP (Surfactant and Alkali Surfactant Polymer);
- Pressure gauges should be installed downhole for accurate bottom-hole measurement.

Injection program and start-up

When injecting in a mature reservoir, it is paramount to have a good water injection baseline with stable injection rates and pressures to compare with polymer injection. There are usually two main ways to start a polymer injection:

- Start with the same injection rate as waterflood and systematically increase the viscosity while monitoring injection pressure and reservoir response: for instance, 1/3 of target viscosity, then 2/3 and finally target viscosity;
- Start with the full target viscosity and at 1/3 of the target injection rate, then 2/3 and finally full injection rate;

The first strategy should help to obtain a good understanding of the flow regime, differentiating between linear and radial/matrix flow and can be easier to adjust viscosity as necessary until the desired balance is achieved. In theory, if the flow is completely radial – into all zones in a vertical injection well, or into 100% effective, wellbore length in a horizontal injector – an increase of viscosity from 1 to 2 cP at a given rate should lead to almost 50% injectivity loss (compared to water). If all injection guidelines to prevent polymer degradation have been respected and if no significant injectivity loss is observed, then it is likely that another phenomenon is occurring (microfractures, dilation, channeling, polymer degradation, etc.).

Continuous injection and monitoring

Water quality can be analysed in conjunction with probes for oxygen, salinity (conductivity) and periodic sampling for iron content. The level of contaminants should be clearly monitored to adapt the injection strategy, water treatment facilities and choice of polymer.

During polymer injection, pressure and injection rates are usually continuously recorded at the injection side. The Hall plot can be used to track the trends and detect either plugging or fracture formation. At the production side, parameters such as total fluid produced, water- and oil-cuts should be recorded. In the long-term, for a brown field, one should look at:

- Peak oil rate, breadth of peak & response time to flood;
- Average oil rate & oil-cut after peak response;
- Average sustained oil rate & oil-cut to current date of flood;
- Average early time injection rates;
- Sustained injection rates;
- Time before water breakthrough;
- Total oil recovered during the time of pilot.

Pressure fall-off tests can be performed to analyze the flow resistance built by the polymer/oil bank and ensure that viscosity is present. However, this test can be difficult to interpret if moving microfractures are present, which can open or close depending on the rate, pressure and viscosity injecting. A review of workflows, algorithms and tests for fractured wells can be found in Wang et al. (2018). The same can be valid if dilation occurs in unconsolidated formations. A thorough geomechanical analysis and monitoring is therefore necessary to decrease the uncertainties linked to the interpretation of such tests.

Conclusions on monitoring

It is important to design the pre-injection testing and monitoring program to obtain a clear picture of the near-wellbore area and the reservoir before starting injection. The final aim is to minimize the uncertainties on what can be controlled (polymer solution viscosity), to respond to the way the reservoir behaves when the viscous fluid is injected. Techniques and guidelines to preserve viscosity can be found elsewhere (Thomas, 2016) but, in a nutshell, it encompasses selecting the appropriate polymer, the proper well completion and injection protocol. Specific well completions can be designed to ensure that no degradation occurs while providing continuous monitoring (Awan et al., 2014).

Based on the field case review, it is possible to list the methods, tools and objectives for each step of the project implementation to pinpoint the relevant variables for a good understanding of reservoir response and model refinement (Table 2).

Pattern selection & pre-injection testing program	
Pattern selection – representativity Reservoir properties for viscosity selection	Reservoir characterization *
Reservoir properties, geological uncertainties	Gamma ray, neutron/density logs, Vertical Interference tests, temperature gradient in the reservoir
Well connectivity	Tracer test, Injector/Producer relationship (IPR), Interwell tests (Pulse test), Streamline modeling
Geomechanics	Regional and local stress analyses, laboratory tests (triaxial test)
Fracture testing program & assessment	Step rate test **, Hall plot, micro-seismic, downhole pressure gauge, image logs
Injection profile	PLT, radioactive tracer, temperature logging, sonic logging
Oil saturation, sweep efficiency	Saturation logs, single well tracer test, production history analysis, pulse neutron logs, induction logs
Injection start-up	
Reservoir response	Hall plot, downhole pressure monitoring, viscosity ramp-up
Polymer solution Viscosity	Inline viscosity measurement at wellhead***
Continuous monitoring	
Flood front position	4D seismic, passive seismic monitoring, observation wells
In-situ viscosity, resistance factor	Pressure fall-off ****

Near-wellbore response	Hall plot, evolving skin analysis, Injectivity/fracturing index, micro-seismic, intelligent well completion
Project overall efficiency	Peak oil rate, breadth of peak & response time to flood, average oil rate & oil-cut after peak response, average sustained oil rate & oil-cut to current date of flood, average early time injection rates, sustained injection rates, time before water breakthrough, total oil recovered during the time of pilot.
Polymer propagation & breakthrough analysis	Spot tracer test, polymer qualitative analysis (kaolinite flocculation method), polymer quantitative analysis (bleach or starch iodide titration) *****

Table 2 *Important variables and associated tools for polymer injection monitoring*
** Geostatistics (see example in Altundas & Chugunov, 2018). One of the goals is to determine the dominant reservoir facies (permeability, porosity, lithology) to properly select polymer molecular weight and injected viscosity.*
***Step rate test. Should be used carefully in unconsolidated formations.*
**** Inline viscosity measurement at wellhead. As of today, it is very difficult to determine the viscosity after the wellhead and inside the reservoir without affecting the properties of polymer solution.*
*****Pressure fall-off. This test should take into account the dynamics of fracture closing/opening and the rheology and elasticity of polymer solution which impact the flow in reservoirs.*
******Polymer analysis. Polymer molecular weight and viscosity are usually affected by the pumps and production equipment, biasing the conclusions. Polymer quantitative analysis requires on-site laboratory and a good knowledge of the titration methods.*

The objective is to minimize the number of variables involved and monitored and to rank them from the most influent to the least influent on reservoir response. From the previous analysis, it appears that the presence of fractures (or dilation for unconsolidated reservoirs) is one of the main factors favoring injectivity. These features have obviously an impact on how polymer is modeled: polymer rheology is different in fractures and in reservoir matrix at high velocities (viscosity and shear-thickening). For instance, the shear-thickening effect which should lead to increased resistance and pressure (in the model and the field) is likely inexistent when fractures are present and “moving”.

Overview of Remaining Challenges

In the previous paragraphs, the main focus has been the near-wellbore area and the way its characterization will impact injectivity prediction and actual field values. But the global picture also requires looking at 1) how polymer is modelled inside the reservoir and 2) what happens once water injection is resumed.
For the first part, it is necessary to consider resistance factors values obtained during core floods (for different facies, permeability, velocities…) and not the typical rheological curve viscosity vs. concentration obtained in the laboratory. The latter does not capture any of the in-situ phenomena occurring during polymer flow through a rock.
For the second part, the main challenge lies in modeling water fingering through the polymer slug especially through the path of least resistance, i.e. the zones of higher permeability where the relative damage caused by polymer (if any) will be less important. Papers on the topic highlight the numerical model, successive mathematical developments and field cases. The need to properly capture polymer propagation in the reservoir is discussed in detail by several authors (Doorwar, 2015; Doorwar & Mohanty, 2015; Luo et al., 2016, 2016b, 2017). This is essential to predict polymer breakthrough (viscosity, concentration) in the producing wells. It will impact the design or upgrade of water treatment facilities and, further downstream, the possible reuse or disposal of water containing polymer.

Conclusions

A quick review of published field cases where polymer has been injected with success shows that short-term (and very often long-term) injectivity was generally better than expected and/or simulated. It shows that there is something which is not clearly captured or understood during the simulation process and

which leads to pessimistic predictions regarding how much polymer can be injected in the reservoir and at which pressure. As discussed in this paper, three areas require further investigation: 1) the simulation (reservoir model, well model, grid resolution and properties), 2) polymer rheology and features and the way it is modeled and 3) near wellbore and/or reservoir aspects which are not always analyzed in the field and therefore not captured in the model.
A recurrent explanation behind the better-than-expected injectivity is the presence of microfractures (for consolidated formations) and/or permeability enhancement via dilation (for unconsolidated formations). Since this process is dynamic, it is necessary to adapt the 3D model to take into consideration the creation or pre-existence of such features to predict the injectivity, making full use of evidence gathered during pilots.
The proper implementation of monitoring and injection programs should enable reservoir engineers to refine the model on a continuous basis. Such an approach, combined with a good understanding of polymer rheology and behavior, should help to reduce the uncertainties for variables used to model polymer injection, therefore improving future predictions.
Work remains on several aspects including modeling of polymer in-situ behavior and fingering during water chase, two critical aspects impacting the overall business case.

Finally, it can be seen from this review that multi-disciplinary studies are essential for prediction of polymer performance, including knowledge and experience from chemistry, geology, geomechanics, reservoir engineering and production engineering.

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