

Revisiting polymer selection workflows for chemical enhanced oil recovery

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Summary

The workflow used to select and study polymer candidates for polymer flooding has remained relatively unchanged since the first projects were performed in the 1960s. Starting with viscosity curves and filtration test, the polymer candidates are then injected into cores representative of the reservoir from which parameters are extracted for history matching and simulation purposes. Interestingly, all studies follow the same book without questioning the validity of the approaches used or the representativity of the polymer solution studied.

First, what is being qualified is not a polymer but a polymer batch with characteristics that might differ from the next one or from a different manufacturer. Secondly, the polymer solution in the laboratory is pristine and exempt of any minor degradation which will occur in the flow lines and impact the molecular weight distribution as well as resistance factor. Thirdly, almost all corefloods are performed at a fixed injection rate supposedly representative of the velocity in the reservoir. The issue here is that at reservoir conditions, it would be logical to consider fixed pressure drop or drawdown and not fixed rate which resembles an extrusion process likely to happen only in the near wellbore area. Lastly, many corefloods are underused, without mentioning the fact that trying to history match the results instead of checking if the equations can predict the latter reveals a lot about the inadequacy of the approach used to understand polymer flow.

In this paper, we will revisit the existing workflow for polymer evaluation and propose changes to reflect on the wealth of knowledge available and the need to better analyze the field candidates before starting laboratory evaluation.

Before selecting samples and designing a testing protocol, we will show that starting with field appraisal (well selection, completion, spacing, etc.) can accelerate laboratory testing and avoid studying phenomena which might not occur in real conditions such as shear-thickening. Next, we will discuss the laboratory tests required and emphasize the need to assess the differences between polymer batches and solutions prepared in the laboratory vs. field. Finally, at the light of typical core flood results, we will revisit the ideas to screen polymers and discuss how the history matching process has prevented engineers to correctly model polymer injection and eventually predict injectivity.

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Introduction

Polymer flooding is an oil recovery technique that involves enhancing the viscosity of the injected fluid, typically water, to improve the efficiency of displacing oil in conventional reservoirs. This method effectively increases the recovery factor, accelerates production, and reduces the total volume of fluids handled in heterogeneous reservoirs, regardless of the oil viscosity (with a current maximum in-situ oil viscosity of 15,000 cP for field project).

For a project to be technically successful, two critical conditions must be met:

1. The reservoir must be thoroughly characterized and understood,
2. The selection of the polymer and its associated parameters (injected viscosity, pore volume, etc.) should be reasonably de-risked.

Interestingly, in various projects, the lack of desired results is often attributed to the polymer itself rather than considering the complexity of reservoir heterogeneity and accurately estimating the remaining oil content. This aspect is of utmost importance as it directly influences the choice of the enhanced oil recovery technique (EOR), the injected viscosity in case of polymer flooding, and the expected response in terms of water-cut, pressure, and oil-cut variations. In this discussion, we will focus solely on the second part, which involves the selection and characterization workflows of polyacrylamide before injection. The post-injection production of polymer and its characterization will not be addressed here.

Criteria for polymer selection

To summarize the expectations from a polymer used in chemical Enhanced Oil Recovery (EOR), it should enable a cost-effective and efficient increase in water viscosity, ensuring a consistent propagation over the required duration to effectively displace oil in the reservoir.

A water-soluble polymer is expected to increase water's viscosity to reach a desired value, which must remain stable in space and time during the displacement process. Several important aspects need to be considered in this regard:

- Viscosifying power: The polymer should exhibit strong viscosifying power at an economical concentration while taking into account losses linked to retention. Both the polymer and solvent play a role in this, and adjusting the water composition can improve polymer stability, retention, and economics,
- Steady propagation: Polymer propagation should occur steadily over the required pore volume without causing plugging or unexpected pressure build-up. This consideration involves both the characteristics of the polymer and water, as poor water quality can negatively affect injectivity,
- Viscosity stability: The viscosity achieved should remain stable over time under reservoir conditions, with no significant losses due to retention, thermal effects, or chemical degradation.

While these conditions are generally agreed upon within the community, there is currently no up-to-date standard used to homogenize tests and compare findings. Some organizations and authors have raised the issue of standardization, and guidelines have been proposed (see for instance UK Oil & Gas Authority, Dean et al., 2022). Additionally, the API RP63 procedure provides important guidelines, but it is outdated as it only considers the use of the Brookfield viscometer, which greatly limits the evaluation possibilities.

In the next paragraphs, using a modified layout provided by the UK O&G, we will discuss each aspect of polymer selection and characterization, including the focus area, associated risks, presence of standard testing procedures, other methods used, and whether these tests adequately address the risks. We will assume that the water quality meets standard specifications for normal operations (low oil-in-water and solids content) or can be injected without irreversible injectivity decline. For polymer, we assume that oxygen content is below 100ppb unless stated otherwise. Typical guidelines are provided in the table below (Table 1):

Parameter	Value	Remark
Oil in water	<100ppm	Depends on reservoir permeability and removal capabilities. If it affects waterflood performance, then it will likely affect polymer flood's too
Solids	<20ppm <5 microns	If it affects waterflood performance, then it will likely affect polymer flood's too
Salinity	-	Must be consistent over the life of the project (or variations anticipated)
Oxygen content	<5ppb	Stable at 120C over 200 days if no divalent in water
	<40ppb	Almost no degradation (<10%) whatever the level of iron if low divalent content and low temperature
	<200ppb	Almost no degradation (<10%) if temperature < 50C
Iron	Depends on oxygen content	Dissolved iron 2 has no impact without oxygen presence. Iron 3 is the dominant species only below pH = 4. Iron oxides can be flocculated
H ₂ S	Depends on oxygen content	-

Table 1 (Ideal) water specifications for smooth waterflooding/polymer flooding implementation.

Focus: polymer samples

When considering pilots or full field deployment, operators or mandated independent laboratories need to gather polymer samples for testing. Usually, the samples received are small: typically 100 to 500g of product for powders, and from 1 to 5 liters of emulsion, which is normally enough to conduct a variety of tests from rheology to core flooding. At field scale, powder is usually delivered in 25 or 750kg bags, while emulsion is supplied in 1- or 20-tons tanks (Gathier et al., 2020).

What are the risks?

There are several risks associated with collecting small samples in the context of polymer selection:

- Manufacturing abilities: It is crucial, especially for pilot projects or large-scale deployments, to ensure that the selected polymer can be manufactured in substantial quantities economically and with consistent quality. Choosing a polymer candidate without verifying its commercial availability or potential requirement for new investments could prove counterproductive,
- Representativity: similar to any manufacturing process, batch-to-batch variability exists, which means that a small sample collected at one point in time (X) may differ from a sample collected at another point in time (Y). Quality certifications, such as ISO certifications, and certificates of analysis (CoA) help constrain such variability and provide crucial information on the supplier's ability to deliver on its promises. However, to avoid costly surprises, it is essential to conduct supplier audits during the sampling process.

The improper assessment of variability within samples or batches can lead to unexpected issues in the field, such as inconsistent viscosity or the need to increase the dosage to achieve the desired target value. Surprisingly, only a few companies currently take the initiative to audit polymer suppliers before commencing their investigations.

What could be relevant to consider?

For developing chemical EOR projects (non-R&D), it is recommended to:

- Ask for larger samples. It is a way to make sure the products can be manufactured at scale, while assessing variability, and/or,

- Visit and audit the suppliers to verify the certifications, tour the plant(s) and make sure that the required polymers can be manufactured at scale with consistent quality and reasonable pricing.

Focus: polymer solution preparation, and filterability

The preparation of polymer solutions exhibits significant differences between laboratory and field settings (Figure 1). In the laboratory, both powder and emulsion are typically dissolved using a mechanical stirrer operating at 500 rpm. To improve dissolution efficiency, a mother solution at 0.5% or 1% concentration can be considered (Thomas et al., 2012). After dissolution, the solution undergoes a primary filtration step at 200 microns to eliminate fisheyes or lumps, followed by more rigorous filtering depending on the upcoming experiment.

In contrast, the field preparation involves distinct methods for powders and emulsions. For powders, slicing units or eductors are employed to "cut and wet" or simply wet the powder, respectively (Gathier et al., 2016). The wet powder is then transferred to maturation tanks, where the viscosity can fully develop. The mother solution is diluted either in-line immediately after maturation or further at the wellhead. As for emulsions, the process includes one or several static mixers for inversion and dilution. In all cases, optional filters can be added to eliminate undissolved particles. However, these filters may not always be present consistently, and operators might remove them if water quality necessitates frequent changes.

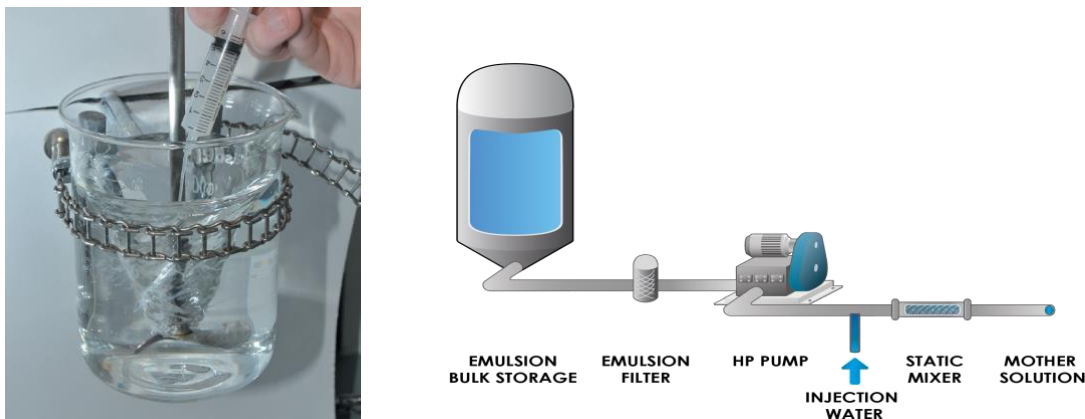


Figure 1 Typical setup for dissolution of emulsion in the laboratory (left) and the field (right). Not at scale. Courtesy of SNF.

What are the risks?

The main risk associated with polymer solutions prepared in the laboratory is their lack of representativeness compared to those obtained in the field, leading to an inaccurate assessment of performance. A second risk is the potential presence of undissolved polymer residues, which, if not filtered, could hinder injectivity (Glasbergen et al., 2015). Addressing the first point, several crucial considerations are:

- Water quality & composition: variations in water quality and composition between the laboratory and the field can significantly impact results. Using model water in the laboratory allows for screening and comparison, but it might present an overly optimistic view of performance, especially if injection water contains contaminants. Water quality can also change during injection, even on a daily basis. Moreover, filtering brines at 0.22 microns in the laboratory is feasible, but it becomes impractical during continuous injection in the field,
- Filtering differences: polymer solutions are commonly filtered in the laboratory but not always in the field. Consequently, the performance observed in the laboratory may substantially differ, especially in porous media,

- Degradation and rheology changes: polymer solutions in the laboratory are typically pristine, meaning they experience little or no degradation. However, in the field, passage through pumps, valves, and perforations can alter the molecular weight distribution, screen factor, and resistance factor inside the reservoir. This, in turn, affects in-situ polymer rheology, including the onset and occurrence of shear-thickening, or viscoelasticity which can be considered beneficial by some authors in reducing oil saturation under specific laboratory conditions. Regarding its potential application in the field, the quasi-impossibility to quantify the potential impact of viscoelasticity compared to regular oil displacement on oil recovery, along with the complexities of real reservoir velocities and polymer properties, renders the occurrence of this phenomenon highly improbable.

Is there any standard testing procedure?

Pre-filtration. Pre-filtering of brine and polymer solution before use for rheology or cores varies greatly from one researcher to another. Some examples randomly picked in the literature are provided below (Table 2):

Reference	Dissolution time	Brine filtering	Polymer solution filtering
Al-Shakry et al., 2019	Not specified	0.22 microns	Pre-filtering in cores
Howe et al., 2016	Not specified	0.22 microns	35 microns filter cloth
Seright and Wang, 2022	1 day	0.45 microns	No filtering indicated
Zhang and Seright, 2015	1 day	0.45 microns	10 microns
Gaillard et al., 2015	12 hours	0.22 microns	No filtering indicated
Wever et al., 2017	2 hours (yard + laboratory)	Not indicated	200 microns
Dupuis et al., 2017	Not specified	0.22 microns	4 -7 microns
Guetni et al., 2019	Not specified	0.22 microns	1 micron
Al-Sofi et al., 2019	Not specified	0.45 microns	5 microns
Gosh et al., 2021	12 hours	0.2 microns cellulose acetate	1 micron polycarbonate
Juarez et al., 2020	Not specified	Not specified	Sequence of 8, 5 and 1.2 microns
Levitt and Pope, 2008	16h minimum		1.2microns

Table 2 Examples randomly selected in the literature showing the variability in filtration procedures.

Within this list of references, a significant variability in the selection of filtration methods used before coreflooding (or rheology testing) is evident. As a result, making direct comparisons between studies becomes challenging, as each research project operates within its unique scope. Additionally, what remains unclear is the rationale behind authors' choices of specific filter sizes over others, as this information is often omitted.

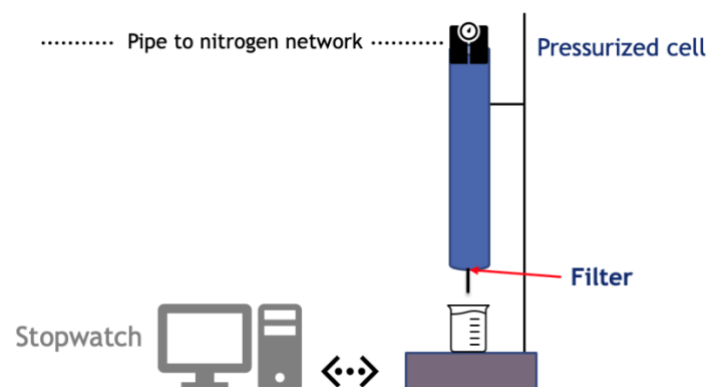


Figure 2 Simplified schematics of filter ratio set-up.

Filter ratio. To characterize polymer solution filterability, the most common test is called the filter ratio and is described in the API RP63 procedure, part 4. It is stated that this test can be used as “reliable indicator of changes in polymer solution but cannot be used routinely to compare different polymers or for predicting reservoir injectivity.”

The test consists in using gas pressure to push a volume of polymer solution through a filter and plot a mass/volume vs. time curve. The filter ratio is then calculated using the following equation (Figure 2):

$$FR_{500} = \frac{t_{500} - t_{400}}{t_{200} - t_{100}}$$

where:

t_{500} , t_{400} , t_{200} , and t_{100} are the time, in seconds, required to filter 500, 400, 200, and 100 mL of the solution, respectively. A good value for the filter ratio is below 1.5.

What are the other methods used?

We have seen the great variability in pre-filtering methods. Regarding the filter ratio test, a few variants also exist in the industry (Figure 3). First, a choice of filter can be made between cellulosic or polycarbonates, with different results depending on the filter and the formula used to calculate the filter ratio (Jouenne et al., 2016; Thomas et al., 2017).

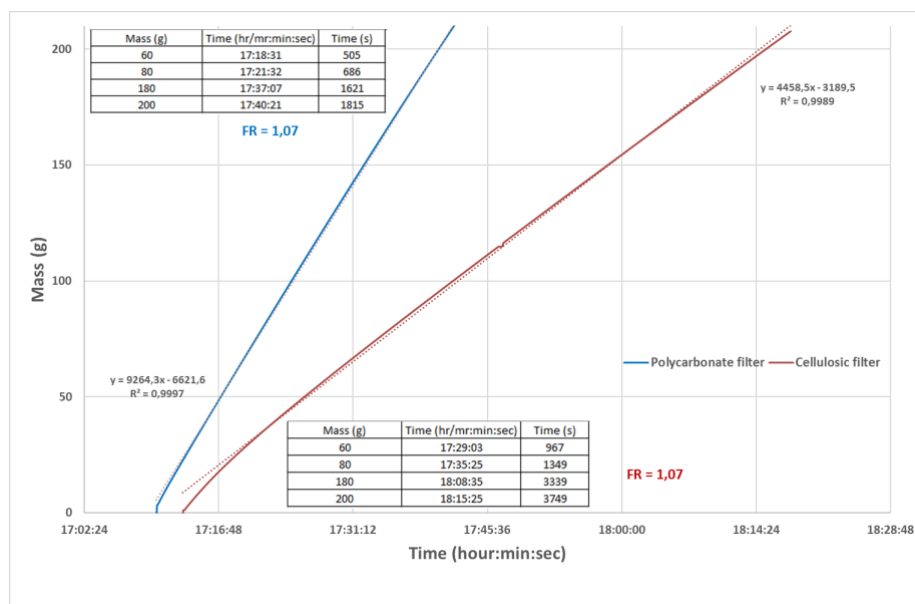


Figure 3 Examples of filter ratio tests using polycarbonate (left curve) or cellulosic (right curve) filters. The FR result depends on the time considered for calculation.

Additionally, for the same filter type, the results can vary significantly between one filter and the next taken from the same lot (Figure 4).

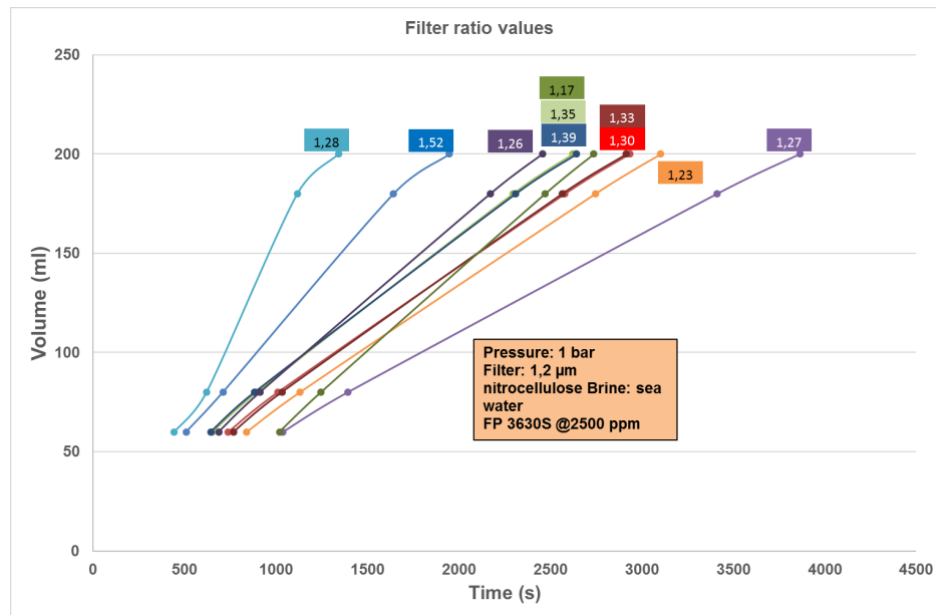


Figure 4 Plots showing the filter ratios measured for the exact same polymer solution through 10 different nitrocellulose filters (Thomas et al., 2017).

Regarding the formulas used to calculate the filter ratio, there is not only one consistently used in the industry (Table 3):

Reference	API RP63, Chapman et al. (2015)	Dwarakannath et al. (2016), Levitt et al. (2009), Koh et al.(2015)	Jouenne et al. (2016), Rubalcava et Al-Azri (2015)	Dean et al.
Filter type	Polycarbonate or cellulosic	Mainly cellulosic	Polycarbonate and cellulosic	Cellulosic
Filter diameter	47mm	47 or 90mm	47mm	90mm
Pore size	1.2µ, 3µ, 5µ	1.2µ	1.2µ & 3µ	1.2µ
Pressure applied	20 psi (1,4 bar)	1 bar	1 bar	15psi
Filter ratio formula	$\frac{t_{500ml}-t_{400ml}}{t_{200ml}-t_{100ml}}$	$\frac{t_{200ml}-t_{180ml}}{t_{80ml}-t_{60ml}}$	$\frac{t_{200ml}-t_{200ml}}{t_{200ml}-t_{100ml}}$	$\frac{1+\beta * 190 mL}{1+\beta * 70 mL}$ See publication for beta
Filter ratio target	<1,5	<1,2	<1,2	<1,2

Table 3 Filter ratio formulas extracted from the literature.

Once more, the researcher is presented with multiple formulas, but without clear explanations of the rationale behind each choice.

Do these tests adequately address the risks?

In 1974, Chauveteau and Kohler stated that evaluating the performance of a polymer flood in a given field requires an understanding of rheological behavior under reservoir conditions and interactions with the rock. They conclude their introduction writing that “an accurate reproduction of field conditions is required in the laboratory to obtain meaningful information on behavior in porous media”. Following this statement, one can wonder if pre-filtration before core floods or the use of filter ratio in the laboratory to qualify polymer solutions is representative of field conditions? Why were filtration tests used for in the past?

For Szabo (1972) and Gogarty (1967), filtration was an experimental tool to better study polymer propagation in cores. Szabo conducted studies using filters with decreasing pore size to determine the effective size of flowing polymer units and assess propagation through known sizes of pore constrictions. Gogarty (1967), in his study aimed at assessing polymer propagation in cores, showed that polymer concentration was reduced when the filter pore size decreased below 2 microns. For Foshee et al. (1976), filtration was needed for solutions prepared for core testing as the core itself is a very efficient filter. It was more a way to remove impurities as the authors understood that drastic filtering could cause filtration at molecular level.

More recently, Levitt and Pope (2008) wrote that “filtration tests have been used here to rapidly gauge the potential for new polymers to be propagated through porous media in the same way that they have been used for years to ensure proper hydration of polymers”. In this case, filtration tests could be considered as screening tests to discard polymer candidates with poor filterability or residues. But strikingly, many studies encountered:

- Do consider filter ratio as an indicator of good solution quality for further field implementation,
- Do filter the polymer solution at 5 microns or less before core flooding and use these results for extrapolation at field conditions.

Regarding the first point and current practices, the flaws are:

- The brine used in the laboratory is filtered at 0.22 microns in most cases, the one in the field is not filtered that finely (if at all),
- The polymer solution is prepared in the laboratory in pristine conditions, the one in the field goes through various devices impacting the molecular weight distribution and characteristics of the final solution,
- The sample used in the laboratory might not correspond to the large batches in the field,
- There's a lot of variability in testing methods, filter types, agitation time, and formulas. A sample that fails at hour 1 might pass at hour 1+15 minutes with more shaking.

As for the second issue, research has shown that filtering a polymer solution at 5 microns or smaller before core flooding will alter the quality of the solution in a manner that wouldn't be observed in the actual field conditions (as using such filters would become an operational nightmare). Al-Shakry et al. mention that pre-filtering would isolate the near wellbore from in-depth reservoir effects, but this overlooks the presence of perforations (for vertical wells) or microfractures in most projects in which cases the solution is just slightly degraded before being “filtered” when entering the reservoir matrix (Zechner et al., 2013, Seright, 2016, Thomas et al, 2019; Sagyndikov et al., 2022).

Considering a terpolymer containing ATBS (sulfonated monomer), a study was performed to assess the impact of shearing on rheology, screen factor, filter ratio, and flow in porous media. In this study, the polymer was either pre-sheared slightly or used as such after preparation of a 5000ppm solution followed by a dilution to 1650ppm using either a magnetic or mechanical stirrer. Brine was 37 g/L with a R^+ of 0.086 (ratio of cationic divalent ions divided by the total of cationic ions). Results of GPC are provided Figure 5 showing change in molecular weight distribution. Instrument is GPC-3, with a chromatography column Shodex SB-807. Detection was performed with a MALS and a refractometer.

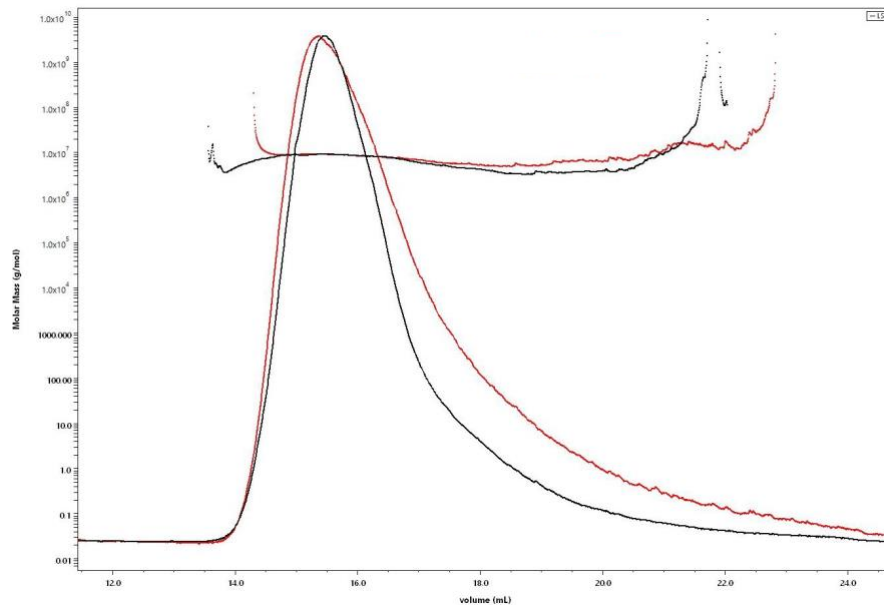


Figure 5 Molecular weight distribution for the non-degraded and degraded polymer solution (red and black respectively).

Core floods were performed in Berea Upper Gray cores in the range of 110 to 180 mD, 1.5" diameter –12 cm long. Retention was determined using the dynamic method at room temperature with 20PV water in-between. The results of the measurements following different preparation methods are given in the table below which should be read top-down (Table 4):

Mother solution	Mechanical stirrer			
Daughter solution	Magnetic stirrer		Mechanical stirrer	
Viscosity at 30s ⁻¹	16.2cP		15.5cP	
Pre-shearing (10.000s ⁻¹)	No	Yes	No	Yes
Viscosity @ 30s ⁻¹	16.2cP (0% loss)	15.2cP (-9%)	15.5cP	13.7cP (-16%)
Screen factor	80		86.5	57
Filter ratio	5 µm	1.2 µm	1.2 µm	1.2 µm
Viscosity @30s ⁻¹	16.2cP (0%)	14.2cP (-11%)	15.5 cP(-5%)	13.5 (-17%)
Screen factor	70.8	58	56	-
Resistance factor	92	50	34	133
Residual resistance factor	-	-	-	50
Retention	-	-	-	104 µg/g

Table 4 Experimental protocols and results for non-sheared or pre-sheared polymer solution.

Rheology and resistance factor curves are also shown below for (non)sheared solutions (Figure 6 a and b), solutions stirred mechanically or with a magnetic stirrer (Figure 7 a and b), and filtered solutions at 5 or 1.2 microns (Figure 8 a and b).

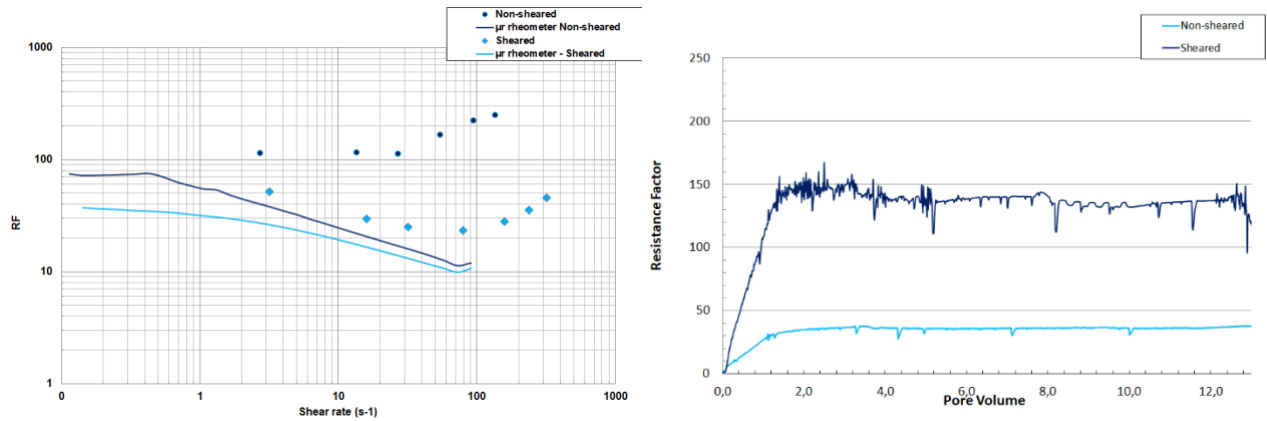


Figure 6. (a) rheology on rheometer and in-situ for non-sheared (dark blue, circles) and sheared polymer solution (light blue, diamonds). (b) resistance factors for non-sheared (dark blue, upper curve) and sheared solutions (light blue, lower curve). Courtesy of SNF.

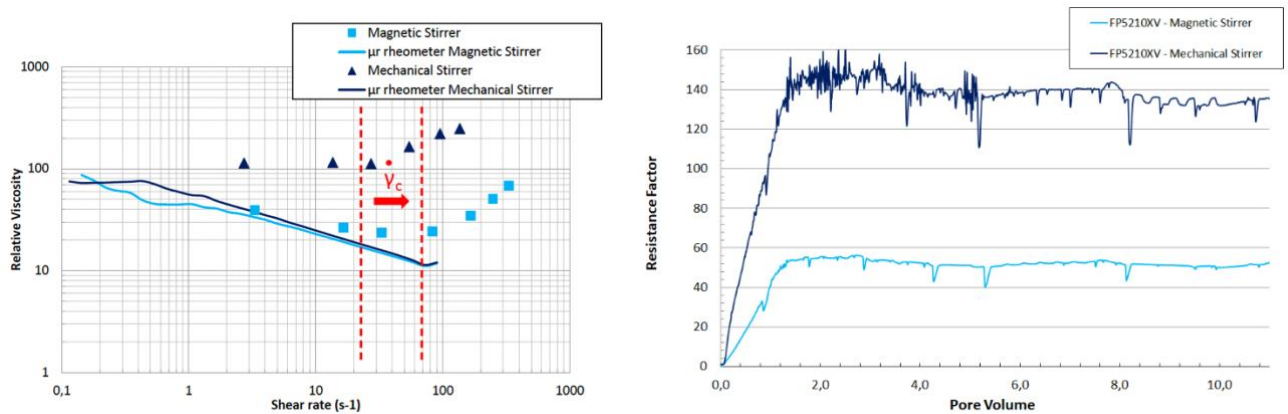


Figure 7. (a) rheology on rheometer and in-situ for mechanical (dark blue, triangles) and magnetic stirrers (light blue, squares). (b) resistance factors for mechanical (dark blue, upper curve) and magnetic stirrer solutions (light blue, lower curve). Courtesy of SNF.

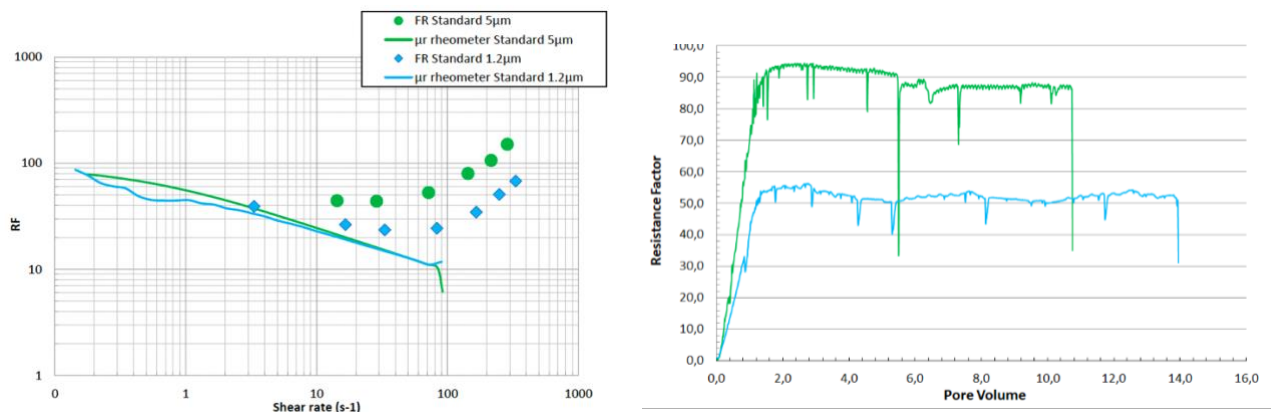


Figure 8. (a) rheology on rheometer and in-situ for standard 5-microns filter ratio (green, circles) and 1.2-micron filter ratio (light blue, diamonds). (b) resistance factors for 5-microns filter ratio (green, upper curve) and 1.2-micron filter ratio (light blue, lower curve). Courtesy of SNF.

From these experiments, we clearly see how each step in the preparation procedure can impact the in-situ behavior of the polymer solution. Especially, a slight pre-shearing yielding a viscosity decrease of 10% leads to:

- A resistance factor decreased by 30% minimum,
- A retention divided by 2,

- A residual resistance factor divided by 3.

Moreover, the choice of stirrer or filter size have a substantial impact on the viscosity of the solution with much lower resistance factors after the use of magnetic stirrer and 1.2-micron filter ratio.

Therefore, the conventional testing methods, besides not truly representing what happens in the field, provide inconsistent results.

What are the difficulties to develop a standard test?

The challenges in creating a standardized test begin with reaching a consensus on how filtration tests help understand polymer behavior in the actual reservoir conditions, putting aside the R&D developments. Since great differences exist between laboratory and reservoir fluids, it is necessary to define the expectations of the test and the value that can be obtained at the light of reservoir complexity. Secondly, it would be beneficial to define a standard equipment set-up, specifying the filter type, size, pressure, formula, etc., as substantial differences exist between protocols.

What could be relevant to consider?

The initial stride in this endeavor should involve procuring pertinent data from the field. This data will then serve as the foundation for designing appropriate laboratory experiments, encompassing factors such as:

- Water characteristics and their fluctuations (Figure 9),
- Shear forces and flow velocities, accounting for the presence of valves and chokes for instance,
- Well completions,
- Identification of fractures, microfractures, and potential skin effects.



Figure 9 Real example of water characteristics variability in the field.view inside the maturation tank.

This accumulation of information becomes pivotal in conditioning the polymer solution to emulate the complexity of its real-world journey. To this end, several recommendations can be put forth to establish a more representative workflow:

- Opt for either field water or a synthetic analog with minimal filtration, mirroring the field conditions. In cases where synthetic water is employed, an additional analysis of

contaminants present in the injection water and their potential impact on polymer stability becomes imperative,

- Prepare the polymer solution to mirror field circumstances: initiate dissolution at a 1% concentration and subject it to vigorous agitation, followed by maturation over a span of 1 or 2 hours, mirroring the typical residence time within maturation tanks,
- If filters are part of the field setup, a similar filtration step can be incorporated,
- Employ dilution and circulation via a compact pump or device to imitate the transportation through conduits leading to the wellhead. To achieve heightened precision, particularly in situations featuring perforated vertical wells, it is advisable to calculate shear forces and replicate as much as possible the conditions within the laboratory. This approach facilitates an understanding of the polymer's response and offers avenues to mitigate adverse effects, such as deploying polymers with enhanced resistance or delayed action polymers.

Subsequent to these preparatory stages, the solution stands ready for utilization in both rheological evaluations and core flooding experiments, obviating the need for supplementary filtration or adjustments. Any protective measures against chemical degradation should be contemplated on a case-specific basis.

Although this method may appear less expedient compared to prevailing laboratory protocols, its intrinsic worth lies in delivering substantial and representative findings (see Wever et al. (2017) for a comparison of yard tests vs. lab).

Furthermore, given the inconsistencies arising from varying procedures and agitation durations, it is cautioned against relying solely on filter ratios to forecast injectivity within cores or reservoirs. Such predictions demand multiple iterations on the same sample to ensure reliability and find trends. An unfavorable filter ratio could signify an array of issues, ranging from incomplete polymer dissolution and inadequate agitation time to subpar filter quality. It is noteworthy that certain polymers, such as associative polymers, may exhibit favorable filter ratios while concurrently plugging permeable cores, (Seright et al., 2011, Gosh et al., 2019). Therefore, the application of filter ratios should be restricted to quality control of specific solutions or batches (yard tests, analog brine) or when comparing various polymers during the screening process or for specific analysis purposes. Even in the latter scenario, it is recommended to perform a minimum of three tests for each polymer to mitigate inconsistencies stemming from procedural and equipment variations and extract useful trends.

Focus: polymer rheology

What are the risks?

Accurate characterization of polymer rheology is an essential cornerstone for the development of a viable project, necessitating the establishment of pertinent conditions that best mirror the flow dynamics within the porous medium of the reservoir. Failure to do so would negatively impact the selection of polymer type, molecular weight, dosage, the injected viscosity, etc.

Typically, the operator sets a desired viscosity level to enhance fluid displacement efficiency within the specific reservoir under consideration. Subsequently, they engage polymer suppliers to identify potential polymer options capable of satisfying these defined requirements, along with the corresponding concentrations. Next, a viscosity-concentration graph is constructed with multiple polymer candidates. The most favorable contenders emerging from this analysis are subsequently subjected to more comprehensive assessment including within core samples. Nonetheless, a challenge persists, stemming from the divergence between viscosity values as measured by the rheometer and the actual in-situ viscosity experienced within the core samples. Indeed, the viscosity measured in the viscometer, even at low rate, doesn't reflect the complexity of porous media propagation:

- The viscosity-shear profiles extracted from rheometer measurements and those attained from propagation tests conducted within cores of different permeabilities may exhibit substantial discrepancies. Even if the viscosity curves obtained via rheometry appear to align closely, the behaviors of two polymer solutions as evidenced by propagation tests in

cores could deviate significantly (molecular weight distribution, chemistry, etc.; see Leblanc et al., 2015 and Figures 6, 7 and 8),

- Well completion and near-wellbore effects are not considered,
- No retention or relative permeability effects. Resistance factors are affected by polymer retention and fluid saturation (presence of oil), and this is not accounted for in rheometers,
- A substantial portion of research lacks a comprehensive grasp of the shear rates prevailing within the reservoir. It is imperative to undertake an initial assessment of these shear rates before delving into sophisticated investigations.

Although the assertions outlined above may appear to align with intuitive reasoning, it is remarkable that the rheological inputs taken from rheometers generally constitute the primary data fed into simulators for modeling polymer behavior. This issue assumes noteworthy significance, especially considering the pivotal role that simulator outputs play for engineers in endeavors such as forecasting injectivity or sanctioning pilot implementation.

Is there any standard testing procedure?

The API RP63 details guidelines for measuring viscosity using a Brookfield rheometer with a UL module at 6rpm equivalent to 7.34 s^{-1} . But limitations exist when considering low viscosity floods or alternative shear rates. Extensive research and characterization have been performed by Jouenne et al. (2019) to provide universal viscosity behaviors based on ex-situ measurements.

What are the other methods used?

Numerous rheometers and methodologies are employed within the industry. Presented below are a few randomly chosen references (Table 5):

Reference	Rheometer	Remarks
Dean et al.,	-	Double-walled Couette geometry
Al-Shakry et al.,	Malvern Kinexus Pro rheometer.	Cone-plate geometry (CP 2/50) for solutions with a viscosity greater than 10 cP, and double-gap geometry (DG 25) for solutions that possess viscosity less than 10 cP
Trushin et al., 2020 201830	MCR 302 rheometer from Anton Paar	-
Guetni et al.,	ProRheo LS300	Couette-like geometry
Stavland et al., 2010 131103	Anton Paar Physica MCR 301	Cone plate geometry. Shear ramp from 0 to 500 s^{-1}
Shankar et al., 2023 211461	-	double gap, cup-and-bob geometry
Skauge et al., 2016 179694	Anton Paar Physica MCR300	Double-gap geometry for low viscosity samples and 75mm cone-plate geometry for higher viscosity samples
Hryc et al., 2022	Kinexus Pro+ rheometer	Couette geometry
Gaillard et al. 2015 177073	Brookfield Model LVTM	UL adaptor
Seright and Wang 212946	proRheo LS-300™ and/or Vilastic VE™ rheometers	-
Johnson et al., 2021 -39 IOR eage	Brookfield DV-I Prime	UL-Spindle at 60 rpm inside globe box

Table 5 Randomly selected examples showing the variability in equipment and geometry used to characterize polymer solutions.

Once again, a variety of rheometers and geometries exist, not mentioning the preparation and protocols used to perform the evaluation.

Do these tests adequately address the risks?

The rheology tests help screen and characterize different polymers but fail to correlate accurately with rheology in porous media at reservoir conditions.

What are the difficulties to develop a standard test?

From a technical perspective, creating standard rheology tests doesn't appear to be the most challenging aspect. The real challenge lies in selecting suitable equipment and making comparisons among commercially accessible options, particularly employing cone plate and double-gap geometries. Constructing viscosity vs. shear plots across various polymer types and concentrations through shear ramps offers a straightforward approach for polymer screening and candidate selection. Moreover, these plotted curves can prove useful for engineering applications (injection equipment design).

What could be relevant to consider?

Characterizing the flow regimes from the surface down to the deeper part of the reservoir should be a priority. Given the typical reservoir characteristics, well spacing, and injection rates, it is anticipated that the prevailing flow regime primarily features low shear rates deep inside the reservoir. The existing approach consisting in measuring viscosity vs. shear for 3 or 5 polymer concentrations around the target viscosity (with the shear being calculated beforehand specifically for the reservoir of interest) can provide enough information for further evaluation. This would require an agreement on how to translate a velocity in porous media into a shear rate.

Focus: polymer shear degradation

What are the risks?

The risks associated with polymer shear degradation in polymer flooding can be significant especially offshore where it is difficult to remove or bypass chokes. The process can lead to a loss of both viscosity and resistance factor due to excessive shear forces acting on the polymer solution (Seright, 1980, Sorbie & Roberts, 1984, Garrepally et al., 2020). Consequently, the desired fluid properties necessary for effective reservoir sweep and displacement may diminish, thereby undermining the overall success of the polymer flooding process. In attempts to counteract this degradation, there is a potential for overdosage of polymers, which introduces another set of challenges including operational inefficiencies and increased costs.

Is there any standard testing procedure?

The API RP63 describes two mechanical degradation tests, one through a capillary and the second through core either at fixed rate or pressure drop. A typical set-up for the capillary degradation test is shown Figure 10.

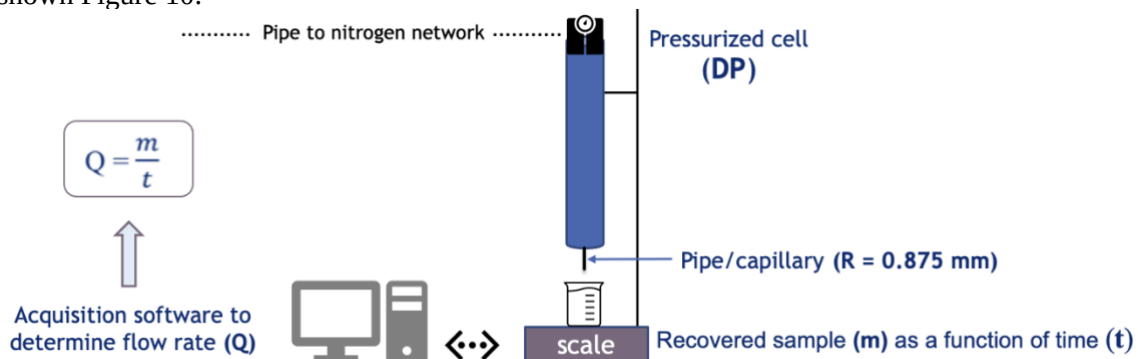


Figure 10 Schematics of a typical set-up used to evaluate mechanical degradation.

The test with a capillary can provide useful guidelines to select the most robust polymer when shear is expected and can't be avoided (Gaillard et al., 2017).

What are the other methods used?

Other methods used to assess mechanical degradation propose:

- The use of extensional viscometer (Azad & Trivedi (2018b, 2019),
- Conducting yard tests with chokes, valves, pipes, etc. (Husveg et al., 2021).

Evaluating the performance of polymer during yard tests provides the most realistic inputs for a proper characterization of the polymer solution. While this may involve substantial expenses, it holds significant merit when considering the economic implications and operational expenditures associated with standard chemical enhanced oil recovery projects.

Do these tests adequately address the risks?

Replicating the pressure differentials encountered in the field within a laboratory setting proves challenging (Jouenne et al, 2015). Although these tests offer a comparative gauge of shear stability among various polymers, they often fall short of providing precise measurements of absolute viscosity reductions in field conditions.

What are the difficulties to develop a standard test?

The main challenge once again is to precisely calculate the shear in the injection facilities down to the sand face and understand if fractures are present which could help minimize degradation.

What could be relevant to consider?

As discussed in the paragraph dealing with polymer solution preparation and filtration, it is important to start by assessing the shear in the installations down to the reservoir and condition the polymer solution accordingly to account for potential viscosity or resistance factor loss (Puls et al., 2016, Garrepally et al., 2020). For perforated vertical wells where fractures likely exist, the polymer will experience shear before entering the matrix. For horizontal wells, it is necessary to calculate the shear at the sand face knowing the actual sweep efficiency in the well and consider when present liners or flow control devices (Bouts et al., 2014). Also, whenever possible, everything should be done to minimize the risks:

- Remove or open chokes,
- Change valves, pumps,
- Reperforate the wells, stimulate,
- Clean the wells.

When not possible (for instance offshore), going through a setting or yard test with conditions mimicking the field's become important. Finally, it is possible to play on chemistry by adding ATBS (Acrylamido Tert-Butyl Sulfonic Acid) whose improved resistance to shear is known (Figure 11; see Gaillard et al, 2017, Zaitoun et al., 2011) or by considering delayed viscosity polymers.

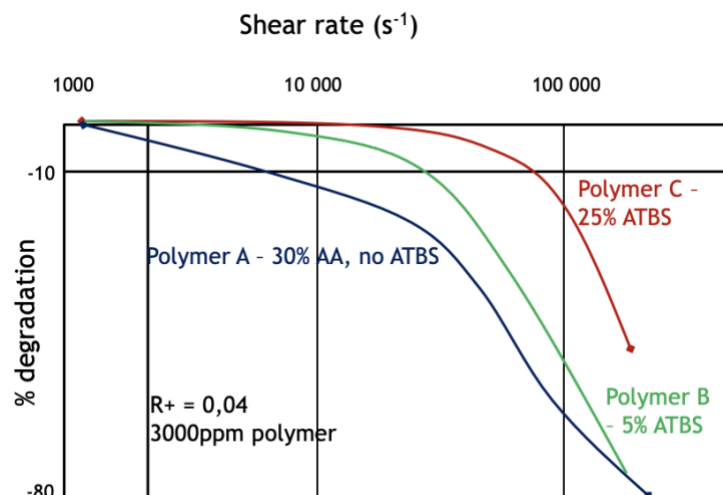


Figure 11 Polymers containing ATBS show shear tolerance (adapted from Gaillard et al, 2017). AA = acrylic acid, ATBS = Acrylamido Tert-Butyl Sulfonic Acid.

In the context of low-permeability reservoirs, certain researchers contemplate pre-shearing of polymers to enhance injectivity and propagation (Gosh et al, 2017, Schmidt et al., 2019). However, in light of the findings presented earlier in this document (Figures 6 to 8), a prudent approach would involve initially calculating the shear in the injection lines down to the reservoir since slight shear can improve greatly propagation and shift the molecular weight distribution towards a more acceptable one. Introducing additional shear could potentially be excessive and unnecessary. It might even be wise to consider polymers with higher molecular weights whose light degradation could facilitate propagation in low permeability reservoirs, while improving economics.

Focus: polymer thermal degradation

What are the risks?

Once within the reservoir and subjected to temperatures exceeding 50-60°C, polymer hydrolysis becomes a potential concern (Jouenne, 2020). This process can trigger polymer precipitation in the presence of multivalent cations, resulting in the depletion of polymer flood viscosity (Figure 12). In offshore environments characterized by considerable well spacing, a polymer might reside within a reservoir for years. Consequently, ensuring the extended thermal stability of the polymer becomes imperative to sustain flood viscosities over the long term. It is worth noting that long testing periods can potentially delay project implementation.

Selecting the appropriate chemistry necessitates a comprehensive assessment of the duration spanning from the initiation of injection to the point of re-entering the water injection phase for each pattern. Upon resumption of water injection, there exists a strong likelihood that water will not effectively displace the polymer slug, but rather finger through it. At this moment, the polymer would cease to provide any advantageous effects, and its sustained stability becomes unnecessary. Therefore, choosing a polymer to achieve a 3-years stability in reservoir while its injection will span 1.5 year might look overkill. Sequentially injecting distinct polymers within the same slug could offer a rationale for optimizing economic efficiency.

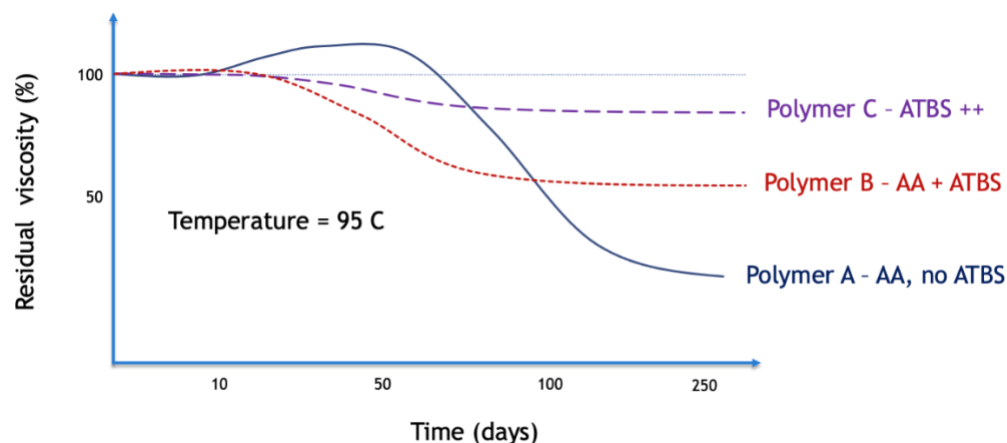


Figure 12 Example of graph displaying the residual viscosity vs. time for 3 polymers with ATBS (Acrylamido Tert-Butyl Sulfonic Acid) and AA (acrylic acid). Synthesis from Gaillard et al., 2017.

Is there any standard testing procedure?

The API RP63 provides guidelines to evaluate thermal stability using glass ampoules. At high temperatures and depending on the protocol, these can leak and alter the results. Several protocols exist and involve:

- Stainless steel ampoules, passivated,
- A glove box with anaerobic atmosphere,
- A low shear rheometer inside the glove box,

- An iron detection kit, to periodically check the ampoules' ageing.

Several guidelines and robust protocols can be found in Seright (2010), Seright and Skjevrak, 2014, Jouenne et al., (2016), and Rodriguez et al, 2016, and Gaillard et al. (2017), and will not be discussed in detail here.

What are the other methods used?

To minimize the time spent on thermal stability studies, researchers use the Arrhenius law and accelerated ageing methods to mimic what is happening inside the reservoir during the transport of polymer. Examples of these techniques can be found in Seright (2010), Nurmi et al. (2018), Sandengen et al., 2018, Seright et al. (2021), and Shankar et al. (2023) for instance.

Do these tests adequately address the risks?

Long-term stability of testing of polymer solution in glove box can be envisaged to monitor the viscosity variations over time. However, practicality concerns may arise in situations involving lengthy residence times or the need to examine multiple parameters, such as chemical degradation. In such instances, this method might become tedious, necessitating the handling of numerous ampoules and samples. An Arrhenius analysis should be considered to extrapolate and estimate polymer stability for long residence times.

What are the difficulties to develop a standard test?

Performing long-term stability tests requires specific equipment and HSE standards. Additionally, the ampoules employed for storage must ensure the absence of contaminant release and maintain their impermeability.

What could be relevant to consider?

When considering long-term stability tests, it is advisable to start with an Arrhenius analysis to obtain relevant indications and compare with the body of literature to choose the most appropriate polymer (Seright, 2010, Seright et al., 2021).

Focus: polymer chemical degradation

What are the risks?

The existence of contaminants within the injection water, including substances like iron, oxygen, or H₂S, as well as the introduction of incompatible chemicals such as cationic biocides, holds the potential to deteriorate viscosity. This degradation can pose a significant risk, jeopardizing the overall effectiveness and achievement of success in a polymer flood project.

Is there any standard testing procedure?

While a universal standard is not established, numerous researchers have outlined comprehensive protocols involving the utilization of a glove box (Jouenne et al., 2016, Seright, 2010). These protocols serve as a solid foundation for any future investigations and could significantly benefit from wider adoption and standardization efforts.

Do these tests adequately address the risks?

When performed in a controlled environment, these tests can provide useful insights on the degradation potential if contaminants are present.

What are the difficulties to develop a standard test?

A standardization process would be beneficial for all researchers in the industry.

What could be relevant to consider

The most straightforward approach to ensure the prevention of any issues is to remove oxygen from the flow stream in the field. When oxygen is present, existing literature provides insights into assessing the effects on the polymer and viscosity.

Focus: polymer behavior in porous media

What are the risks?

The most important test to select the best polymer candidate remains the injection into cores. This test provides information on injectability, retention, and in-situ rheology. The ability of a polymer to propagate in a core with a given permeability cannot be properly inferred from rheology or filter ratio tests. Several parameters are examined, encompassing factors such as resistance, retention, residual resistance, and rheological properties. The resistance factor, also known as mobility reduction, is determined by comparing the pressure drop caused by the polymer to the pressure drop of water under similar flow conditions. This factor serves as an indicator of the apparent viscosity within the core. The residual resistance factor characterizes the enduring reduction in mobility after water injection is resumed (Figure 13).

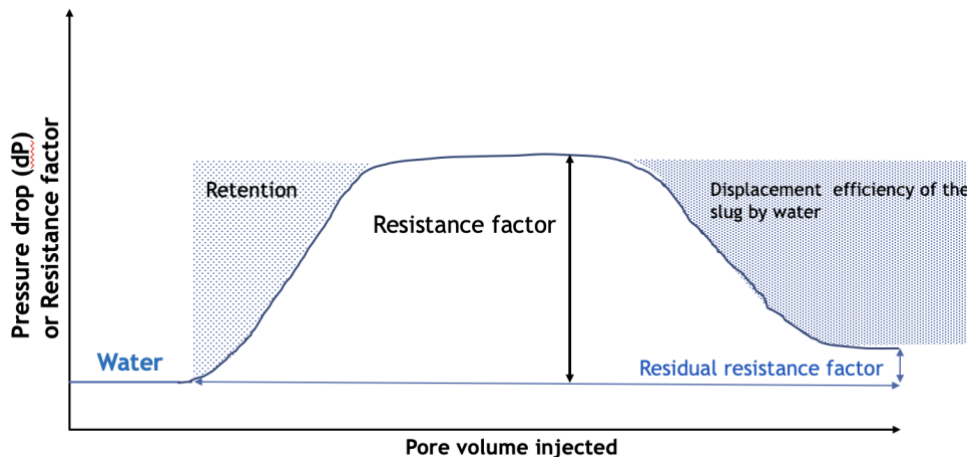


Figure 13 Typical pressure drop profile in a core during polymer injection.

The primary concern evaluated in these tests revolves around the plugging potential of polymer within the reservoir. Such blockages have the capacity to significantly diminish the injectivity of fluids into the reservoir, leading to poor economic returns.

Once again (and again), it is critical to design the core flooding test in a way that correctly represents actual field conditions. We can discuss how most researchers characterize propagation (injectivity) and in-situ rheology, and the limitations when it comes to representativity.

Propagation & rheology. Most tests encompass injecting a polymer solution at a fixed rate in a core over several pore volumes. The number of pore volumes injected varies between authors, either below 20 or above 100 PV. Divergent viewpoints exist regarding the duration of injection, with some advocating for prolonged injection to comprehensively assess plugging potential, while others deem products suitable when pressure drop stabilizes after 2 pore volumes.

A noteworthy observation is that nearly all coreflood experiments employ a fixed injection rate, analogous to an extrusion process which can artificially override capillary forces or relative permeability effects (for instance in tests evaluating viscoelasticity, propagation of various solutions including polymer, nanogels, microgels, etc.). Usually, the goal of these experiments is to acquire resistance factors linked to various velocities. However, when conducting polymer flooding in core samples at a consistent rate, the pressure gradient within the core can significantly exceed the gradient between injection and production wells in the real reservoir. This distinction constitutes the primary disparity between laboratory core experiments and real-field scenarios. Only a limited number of researchers have explored the injection of polymers into cores using a consistent pressure drop, akin to a filter ratio, albeit with a more intricate "filter" system (Szabo, 1972; Qi et al., 2017; Ji, 2022. Szabo (1982) performed experiments under constant pressure conditions, illustrating its impact on polymer solution flow. In a more recent development, Ji (2022) suggested conducting corefloods at a fixed pressure level, calculated based on the gradient between injectors and producers in the field (0,1

MPa/m). The author concludes that this approach yields a closer alignment with field observations, particularly after subjecting the solution to some conditioning (shearing) to replicate the conditions observed in the field before entering the reservoir.

In practical reservoir operations indeed, the sole region where a comparable fixed rate might apply is the near wellbore zone, where (micro)fractures tend to be consistently present, as supported by an increasing number of authors in studies related to both vertical and horizontal wells (Gumpenberger et al., 2012, Zechner et al., 2013, Clemens et al., 2013, Seright, 2016, Thomas et al., 2019, Sagyndikov et al., 2022, Wang et al., 2022). Consequently, for waterflooded reservoirs, only a minor segment of the reservoir near the wellbore zone, including perforations, microfractures, or pre-existing water fingers, will experience a significant influx of polymer solution. Once the fluid velocity and shear diminish, the primary determinant of the advancing front becomes the pressure drop. This implies that if the polymer obstructs the narrow passages (pore throats), the geometry of the front will change. This change can lead to a reduction in injectivity, enhancement of fractures, or a combination of both effects. It is likely that the flow regime in the near wellbore goes from linear (where perforations, fractures or similar features exist) to (pseudo)radial deeper inside the reservoir once the velocity drops. The objective is to maintain a sufficient gradient to allow displacement of both oil and polymer fronts without creating a pressure barrier (Wang et al., 2022).

In the context of linear core tests, the challenge pertains to accounting for elevated flow rates and the potential for shear-thickening behavior. This behavior is likely to manifest only if the solution directly enters the matrix at rapid rates, a situation for which injectivity is expected to decline dramatically or the polymer to be instantaneously degraded, observations that are not matching field data (Thomas et al., 2019). Linear cores are better suited for investigating low shear resistance factors that correspond to the deeper sections of the reservoir. Authors have also managed to provide predictions for in-situ rheology based on ex-situ measurements (Jouenne & Heurteux, 2017).

In contrast, radial core samples overlook the presence of perforations and fractures commonly observed in vertically perforated wells, as well as the microfractures or dilation found in horizontally oriented wells, particularly within unconsolidated reservoirs.

Another difficulty in evaluating the in-situ behavior lies in properly evaluating the residual resistance factor (Seright, 2016). Two challenges should be understood:

- Instability of the front during displacement of viscous polymer by water (Figure 14). This is the viscous fingering issue which is still poorly captured in simulations and sometimes leads the operator to inject small polymer banks and expect an economic effect,
- Actual pressure drops in the reservoir after polymer that would constrain the water to once again finger through the less damaged zones (high permeability).

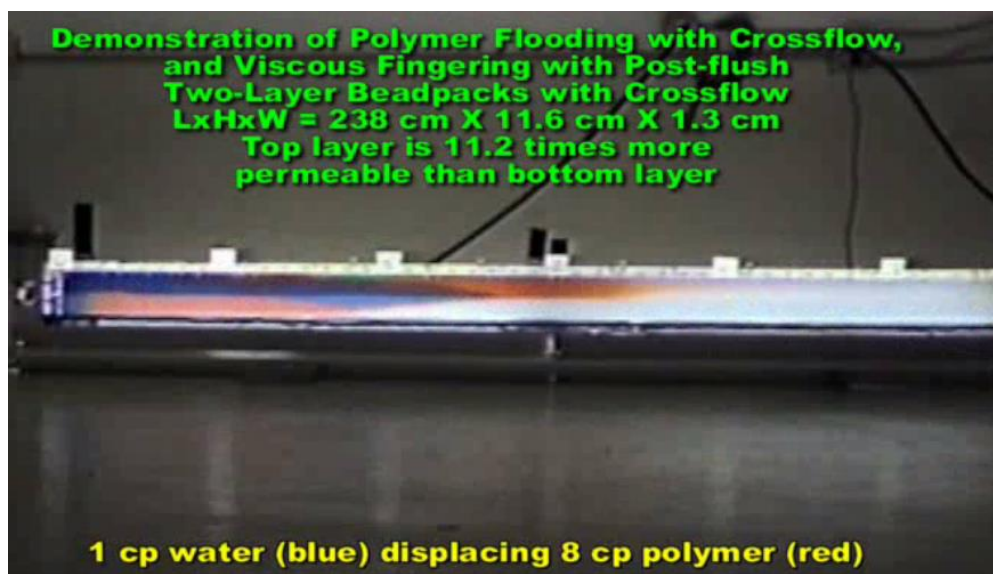


Figure 14 Illustration of water fingering through in the polymer slug in the high permeability layer until crossflow and bypass. From <http://www.prrc.nmt.edu/groups/res-sweep/poly-flood-videos/>.

Lastly, conducting studies within linear cores at constant rates could introduce complications when examining the viscoelastic impacts of polymers on oil recovery. In the evaluation of how polymer viscoelasticity influences oil recovery, most investigations typically maintain a consistent injection rate and/or utilize pristine polymer solutions that do not account for minor alterations that might arise between the wellhead and the first few meters within the reservoir (see for instance Wang et al., 2000, 2001, 2007, Clarke et al., 2015, Howe et al., 2015, Azad & Trivedi, 2018, Jin et al., 2020). Qi et al. (2017) undertook research under fixed pressure gradients, observing effects but with non-degraded solutions. Notably, not all corefloods exhibited heightened recovery. On the contrary, Tahir et al.'s (2017) study highlighted significant declines in viscoelastic properties after mechanical degradation, which aligns more closely with anticipated real-world scenarios, except in cases where fractures are present, potentially resulting in less pronounced mechanical degradation. It is important to emphasize that the underlying concepts regarding the influence of viscoelasticity on recovery are not questioned at this stage. However, the focus lies on the experimental conditions utilized for assessment, which seem to diverge considerably from actual field conditions for most cases.

Is there any standard testing procedure?

In the realm of studying polymer propagation, retention, rheology, or oil recovery in cores, a recent standard procedure is notably absent. Conversely, there are multiple methodologies in existence on how to:

- Pack sand in case of unconsolidated reservoirs,
- Decide the dimensions of the core to minimize measurement errors,
- Restore the core as reducing the iron for instance can impact polymer retention and degradation (Levitt et al., 2015),
- Saturate the core with oil and age it,
- Assess capillary end effects to make sure the core is at residual oil before starting polymer injection,
- Inject polymer (start at high rate, or low rate, etc.),
- Decide on how many pore volumes during injection of polymer,
- Decide on how many pore volumes during water post-flush.

Given the significance of each procedural stage and the variations across studies, the ability to make direct comparisons and derive meaningful insights into key mechanisms (e.g., retention, viscoelasticity) becomes challenging.

Do these tests adequately address the risks?

Several shortcomings can be outlined:

- The absence of standardized guidelines for core restoration and preparation undermines the reliability of comparisons,
- High-rate injection can overstate shear-thickening effects compared to actual field conditions, where factors like wellbore features facilitate polymer entry with minimal degradation (e.g., dilation, fractures). When feasible, it is advisable to revise completion methods to avoid investigating this phenomenon,
- To acquire a comprehensive array of resistance factor and retention values, a diverse range of rock types with varying permeabilities should be encompassed,
- Careful consideration is needed when utilizing residual resistance factor values gathered from both low and high permeabilities, after injecting numerous pore volumes. In real-world conditions, water tends to channel through the polymer slug in areas with low damage and pressure drop, i.e., high permeability zones. The global effectiveness of viscosity grading in delaying water breakthrough is limited,
- Injecting numerous pore volumes entails the potential for using distinct polymer solutions, encountering alterations in injection parameters such as temperature discrepancies

between night and day within the laboratory or variations in operators and preparation methods. These factors introduce greater uncertainty into the testing process,

- Corefloods for oil recovery may not be highly practical for upscaling or constructing a business case focused solely on polymer injection. The comparability of polymer performance hinges on similar saturations and core characteristics.

What are the difficulties to develop a standard test?

The primary hurdle arises from the multitude of protocols currently in existence. Achieving consensus is imperative to define uniform procedures, guidelines, and expectations for these tests.

What could be relevant to consider?

In-situ rheology. To begin with, we might contemplate a simplified yet sturdy proposal, suggesting that viscosity under specific conditions (such as salinity and shear rate) genuinely represents an inherent characteristic of the solution, thereby enabling extrapolation to real field conditions. The second step involves comprehending the distinct flow regimes and characteristics of successive zones encountered by the polymer upon leaving the well. Essentially, whether dealing with vertical or horizontal wells, the shear rate peaks in the vicinity of the wellbore before diminishing rapidly a few meters away (Figure 15).

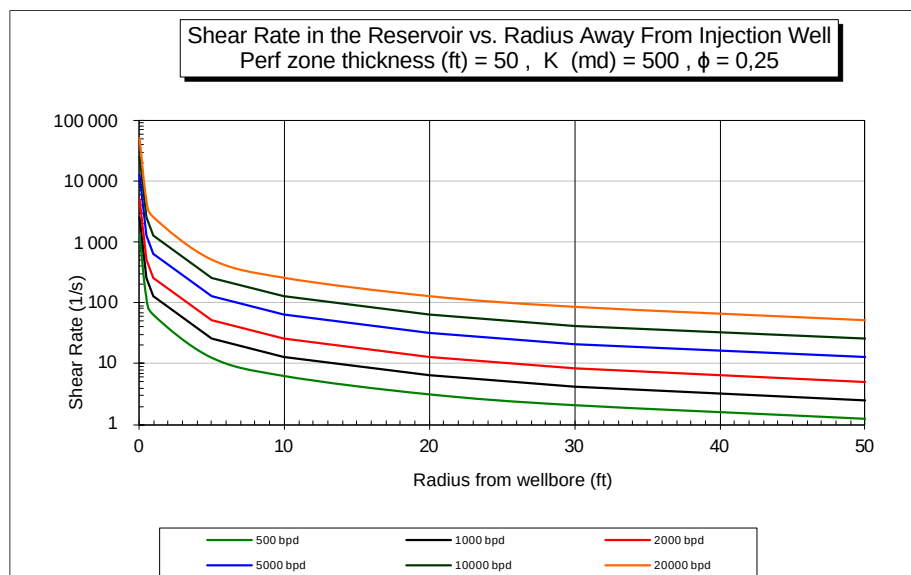


Figure 15 Shear rate vs. distance from the wellbore for different rates in a vertical perforated well.

This region poses the greatest vulnerability for potential alteration of the polymer solution and potential loss of its properties. In this context, understanding the near wellbore area is pivotal, with specific focus on:

- The presence of microfractures or fractures: if these exist, shear-thickening is likely to be absent and may not warrant investigation. It is also advisable to consider essential measures like workover, reperforation, controlled stimulation or cleaning to preempt the need for examining this effect,
- The actual sweep efficiency within the well: if fluid primarily accumulates in a confined zone, elevated shear rates can lead to polymer degradation,
- Opportunities for mitigating shear through judicious choices in chemistry, well completion design, or injection strategies.

Propagation. During the process of polymer selection, two distinct sets of coreflood experiments can be undertaken:

- Propagation, rheology, and retention in characterized analog cores: utilizing well-characterized cores like Bentheimer or Berea, a straightforward approach involving cores saturated with 100% water can be employed. This facilitates the efficient ranking of

multiple polymer candidates with a high level of reliability. The criteria for initial screening encompass factors such as minimal retention, rapid stabilization of pressure drop, and potentially low residual resistance factor. This methodology utilizing analog cores at a 100% water saturation level allows enhanced reproducibility and more accurate comparisons, facilitated by reduced uncertainty in the preparation techniques,

- Polymer characterization in reservoir cores: once the optimal candidate is identified, thorough data collection can be carried out using reservoir cores saturated at residual oil. This phase focuses on parameters including low shear resistance factor and retention. Evaluation of the residual resistance factor should span at least two distinct permeabilities.

In any scenario, certain recommendations stand out (Figure 16):

- Coreholder with multiple pressure taps: Incorporating 2 or 3 pressure taps within the coreholder proves valuable to assess face plugging or retention,
- Utilizing inline capillary for viscosity assessment: employing an inline capillary assists in evaluating outlet viscosity and confirming the absence of degradation,
- Tracers for pore volume evaluation: tracers can be deployed before, during, and after polymer injection to accurately quantify pore volume and breakthrough times,
- Derivative of pressure drop for stabilization ranking: employing the pressure drop derivative aids in ranking polymers by assessing stabilization,
- The priority lies in acquiring low shear resistance factors across permeabilities that represent the reservoir variability,
- Consideration of achievability in field: if the coreflood is conducted at a constant rate, it is essential to verify that the measured pressure drop during polymer injection is achievable within the relevant field conditions.

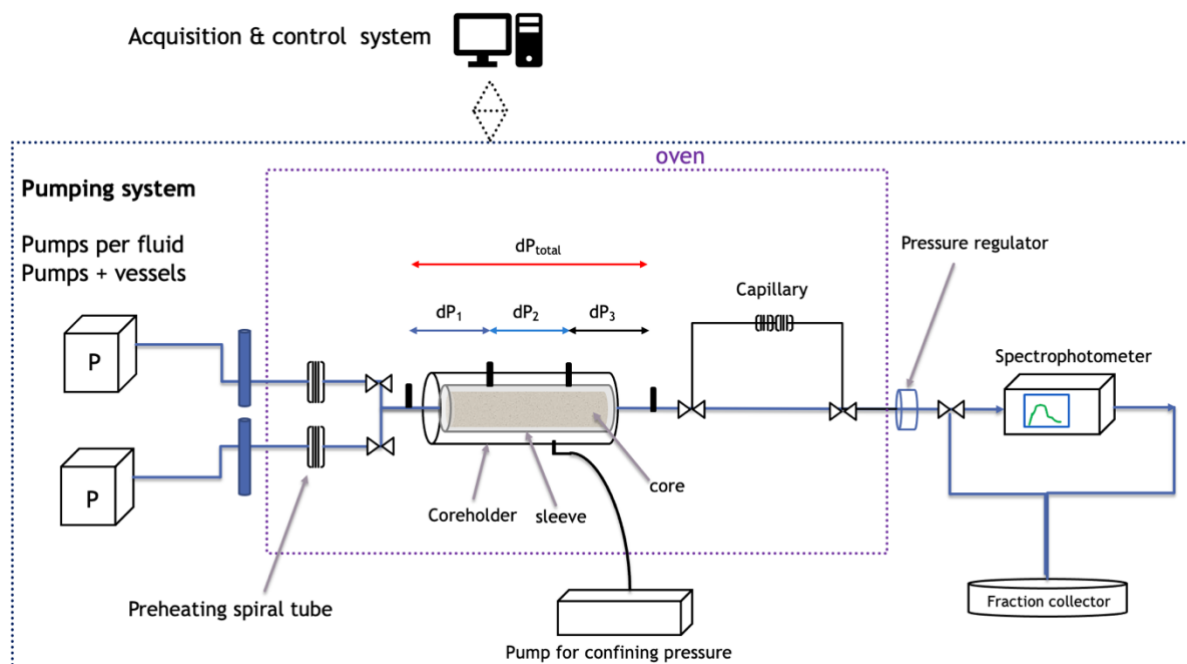


Figure 16 Example of coreflooding set-up with 3 pressure taps on the coreholder. The pressure regulator can be removed if degradation is expected. An oxygen probe can be added inline to assess potential leaks, especially at high temperatures.

In summary, coreflood tests are most effective when employed to contrast various candidates under straightforward conditions within familiar core samples. Moreover, for evaluating propagation and retention, coreflood experiments utilizing reservoir plugs at residual oil saturation can be valuable, and it is recommended to account for diverse permeabilities in such cases. Additionally, developing standardized procedures is a must to allow fair comparisons between researchers.

Focus: polymer retention

What are the risks?

The occurrence of polymer losses due to retention can contribute to reduced viscosity. Elevated levels of adsorption can lead to the postponed advancement of the polymer front, potentially causing delays in the arrival of an oil bank and necessitating extended periods of polymer injection. Such delays can exert a significant influence on the project's economic viability. Excessive measured adsorption levels might even lead to the exclusion of a project from consideration.

Is there any standard testing procedure?

Various methodologies fall within the scope of quantifying polymer retention/adsorption, encompassing two main categories, some of which are described in API RP63. The first group comprises static techniques (Rashidi et al., 2010; Li et al., 2017), while the second encompasses dynamic methods (Osterloh and Law, 1998). The static method typically involves utilizing crushed rock samples mixed with a polymer solution of known concentration. Following a soaking period, a centrifugation process separates the solid and liquid phases, enabling determination of the remaining polymer concentration via titration. Adsorption is subsequently calculated through difference. However, this approach presents notable limitations. Primarily, the available surface area for polymer-rock interaction surpasses that within a consolidated or unconsolidated reservoir. Additionally, it fails to account for the impact of oil on retention.

The dynamic approach, on the other hand, involves injecting one or multiple polymer fronts alongside a tracer (Osterloh & Law, 1998). In cases where two fronts are utilized with a tracer, retention is assessed by calculating the area between the normalized polymer curves, specifically at the 0.5 ratio cutoff (effluent concentration/initial concentration), Figure 17. The tracer aids in determining the inaccessible pore volume (IAPV).

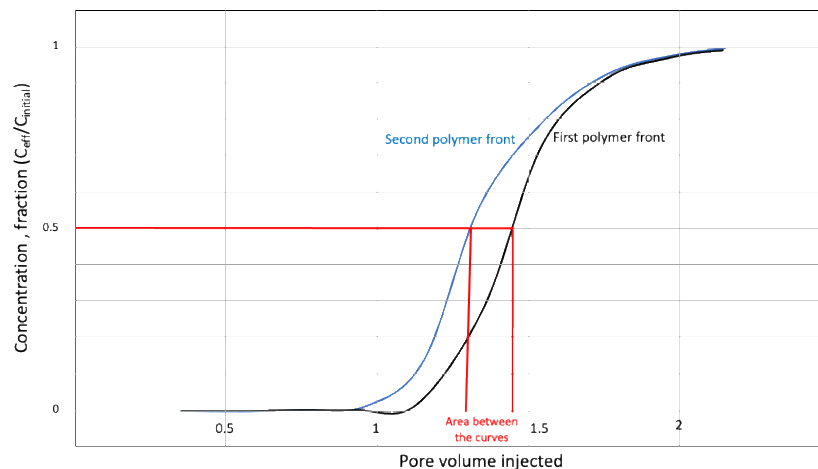


Figure 17 Normalized polymer concentration curves following the dynamic retention test. Retention is calculated by considering the area between both curves at 50% of the plateau, knowing the mass of rock and polymer concentration.

What are the other methods used?

A large slug approach and a recycle method are also described in the API RP63.

Do these tests adequately address the risks?

Dynamic retention tests serve as a suitable means to compare multiple polymers and attain magnitude estimations for a particular rock type extracted from the reservoir. Nonetheless, these tests frequently offer incomplete insights, as they fail to comprehensively capture the reservoir's heterogeneity through a limited number of core flood experiments. Several researchers have also discussed the impact of various parameters on retention and how their characterization is essential to represent the actual field conditions (Levitt et al., 2015, Zhang & Seright, 2015, Wan & Seright, 2016, Ilyasov et al., 2021). Seright & Wang (2022, 2023) have reviewed the literature on retention and write that a consensus

appears concerning several aspects of polymer retention in porous media except for the fact that polymer retention doesn't seem to be greatly affected by the presence of residual oil. It would have been insightful to delve into the core preparation and restoration protocols, along with the methodologies employed for preparing polymer solutions that yielded these findings. In contrast, they showed that a review of inaccessible pore volume (IAPV) in the petroleum literature revealed serious discrepancies due to incomplete and inconsistent volumes of brine flushed during IAPV measurements.

What are the difficulties to develop a standard test?

A global framework already exists but could use some formalization and sharing among peers. Moreover, procedures for core restoration and preparation might greatly impact the results and would also require standardization.

What could be relevant to consider?

Several cores representing the variability of rock types within the reservoir are needed to quantify retention. For pre-screening, static retention methods using crushed samples can be envisaged. But for more accurate determination, it is recommended to perform retention tests using the two-fronts dynamic method in cores at residual oil saturation. This approach proves particularly crucial for carbonate samples due to the potential influence of wettability on how the polymer interacts with the rock surface. The addition of ATBS within the polymer has also proved to help decrease polymer retention sometimes by more than 50% (Ilyasov et al., 2021, Seright & Wang, 2023).

Brief: polymer modeling from cores

It is quite remarkable that the rheological inputs taken from rheometers constitute the primary data fed into simulators for modeling polymer behavior even though there are clear and known differences between how polymers behave in rheometers and how they behave in porous media. Also, while equations exist for modeling polymer behavior in porous media, many authors prefer history matching corefloods over predicting pressure drop in well-characterized cores (see example of predictions in Su et al., 2015). These issues assume noteworthy significance, especially considering the pivotal role that simulator outputs play for engineers in endeavors such as forecasting injectivity or sanctioning pilot implementation. How frequently has the author encountered situations where operators have dismissed the notion of a pilot because simulation results indicated that injecting a fluid with a viscosity of 5 cP into a multi-Darcy reservoir would lead to pressure escalation within a mere couple of hours? This occurred even in the face of field data from analogous reservoirs that presented contrasting evidence. Limited investigations have sought to reexamine modeling methodologies. As an illustration, a recent paper authored by Tai et al. demonstrated the inaccuracy of the Peaceman formula for pressure-equivalent radius in the context of non-Newtonian polymer solutions, leading to a less optimistic outlook on injectivity. Some other typical issues with simulations and black magic are summarized in Wang et al (2022).

There are valuable instances of reevaluating simulators on simpler scenarios to ensure understanding and integrity of underlying principles. A basic prediction of pressure drop using minimal parameters should help validate employed approaches. The challenge in history matching is identifying suitable parameters to adapt to reproduce the observed outcomes, especially in polymer flooding due to numerous variables which can be considered. This effort is worsened when using rheological curves instead of resistance factors for varying permeabilities or keywords for effects whose existence might only be a laboratory artifact. Furthermore, certain challenges prove resistant to resolution yet exert a significant influence on the design process, with viscous fingering standing as a notable example. Why do engineers tend to match the pressure drop in corefloods instead of using it for simulations?

Conclusions

The paper addresses two primary challenges, namely the necessity for updated standardized protocols and the pursuit of representativeness. Addressing the first challenge demands a coordinated global endeavor to ensure proper design and comparability of all research endeavors.

As for the second aspect, there seems to be a communication or knowledge gap within certain companies, creating a hindrance between laboratory research and real-world field/reservoir conditions. This disconnect substantially delays or obstructs the feasibility testing of ideas, concepts, and models through piloting, while also impeding transparent reporting of failures. In the context of polymer flooding, given that operational expenditures constitute a substantial portion of any project, it would be prudent to ensure that pre-implementation evaluations accurately reflect the big picture.

To achieve this goal, it would be advisable to consider a “reverse” approach for polymer flooding projects, which involves:

- Ensuring the large availability and quality of selected chemicals before testing,
- Thoroughly characterizing the reservoir and near wellbore areas to the best extent possible. Testing parameters should be derived from actual field and reservoir data, rather than relying solely on conventions,
- Defining the anticipated properties of the polymer solution upon entry into the reservoir, rather than relying on pristine polymer solutions for testing.

Indeed, it has been observed that the inherent characteristics of the polymer solution can undergo alterations due to various factors within the preparation process. These factors encompass aspects such as the equipment employed for dissolution, filtration techniques along with filter size, pre-shearing measures, and the protocols employed for coreflooding.

Even a minor deterioration in the solution's quality has the potential to trigger a substantial decline in critical parameters like resistance factor, retention, and residual resistance factor. Such alterations can necessitate a reevaluation of project design and emphasize the importance of recreating pertinent field conditions to mitigate these challenges.

Furthermore, it's plausible that certain outcomes obtained from coreflooding experiments could be influenced by the very protocol being used, including factors like a fixed injection rate. This introduces the possibility of capillary forces and relative permeability being overridden artificially in the way that would not happen in the field.

Finally, careful consideration is essential when incorporating rheological input into modeling, particularly if it is derived from sources other than coreflooding experiments.

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