DESIGN AND IMPLEMENTATION OF A POLYMER FLOOD

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SUMMARY

Proper implementation of a successful polymer flood is facilitated if certain engineering requirements are considered. A recommended sequence of events is outlined to describe engineering requirements for a polymer flood. An overview of the feasibility, design, and start-up phases and a more detailed discussion of some aspects follow.

Preliminary Feasibility Study

Prior to extensive laboratory work, a cursory waterflood performance evaluation is undertaken to confirm that polymer flooding warrants a detailed investigation. Oil recovery and reserve estimates are reviewed. Since the economics of a polymer flood is heavily dependent on injection rates, a great deal of time is spent examining rates and pressures.

Frequently, pressure transient tests are performed during the screening phase since the resulting information often improves non-EOR operations, such as well stimulations and pattern selection. Buildup tests are run on producers, and falloff tests are run on injectors to measure oil and water mobilities, permeability, and wellbore damage. Multiwell tests are used to identify the presence of directional permeabilities and confirm interwell permeabilities from the single well tests, useful data when selecting patterns and well density.

During the laboratory screening phase, polymer solutions of various concentrations are prepared in both injection and produced water at ambient and bottomhole temperatures. Viscosities and screen factors of the solutions are measured along with oil and water viscosities. Polymer solutions are then pumped through a reservoir core to check plugging tendencies. A stabilized differential pressure across the core, along with equal inlet and outlet polymer concentrations, indicate minimum plugging.

Design Phase

Rock and fluid properties such as porosity, permeability, capillary pressure, and oil-water relative permeability are measured early in the design phase for engineering calculations. Based on the method of well completion and the type of polymer selected, it may be necessary to investigate the extent of polymer mechanical degradation that can occur at the wellbore. Additional core work with polymer solutions may include measuring apparent viscosity, retention, dispersivity, and may conclude with oil recovery tests.

Long-term stability of polymer solutions is evaluated at bottomhole temperature in the presence of core material. If required, the effectiveness of different types of additives and their concentration limits are determined.

As data from the design phase laboratory work become available, engineering calculations are performed to project waterflood performance. Then a polymer flood is forecasted, and chemical requirements are estimated. A minimum of three vendors should be selected as potential polymer suppliers, thus ensuring a competitive price situation. Based on the estimated chemical requirements, quotes are requested from the vendors and subsequently are used in the economic calculations.

The most cost-effective polymer is, in turn, field tested to confirm the laboratory data. A small volume of polymer solution including a non-adsorbing tracer is injected. The injector is then backflowed or swabbed. Analysis of the produced fluids provides an in-situ estimate of retention, degradation, and dispersivity. Next, a longer term injectivity test is conducted to determine injection rates and pressures, in-situ polymer viscosities via fall-off tests, and the types of flow control devices that are necessary to minimize shear degradation of the polymers.

Assuming a favorable review of the laboratory work, field test results, and the engineering forecasts, the optimum polymer slug can be calculated by computer simulation. Initially, a waterflood based on fluid mobilities is simulated; then a number of runs can be made with various polymer slug sizes of different viscosities. Economics of the incremental oil are used to arrive at the optimum slug. Final laboratory oil recovery tests can demonstrate the improvement in displacement efficiency which is included in the computer forecast along with improvements in areal and vertical sweep efficiency.

Project Start-Up and Monitoring

Product quality control is assured by checking the arriving chemicals with specifications agreed upon during the design phase. The logistics of large quantitites of polymer with delivery by rail or truck includes proper car loading and insulation, dryers and scales at the unloading point and storage facilities at the injection site. For smaller applications, polymer delivered in drums (for liquids) or bags (for dry powders) may be used.

Injected fluid quality is maintained by routinely monitoring viscosity, screen factor, and bacteria at key points in the injection system after the wellhead flow control devices are adjusted. Continued surveillance of fluid viscosity and producing well response during the course of polymer injection provides data for operational changes should they be required.

DISCUSSION

Many of the requirements for the successful implementation of a polymer flood are itemized in Table 1. Some of these requirements will be discussed in more detail. Not all of the items will be appropriate in every instance; for example, some operators may feel that a preliminary project study plus the selection of a non-plugging polymer, and a polymer flood forecast will satisfy their requirements. The program is divided into phases so that the project can be assessed during the work and, if necessary, can be terminated early with a minimum of expenditure. The early tests can be completed quickly and require little cost. If the project appears promising, more extensive testing is then performed.

I. Laboratory Design

A. Reservoir Screening

In some instances, only one type of enhanced recovery technique is applicable for a specific field condition, but in many instances more than one technique is possible. The selection of the most appropriate process is facilitated by matching reservoir and fluid properties to the requirements necessary for the individual EOR technique.[1] Screening criteria for polymer flooding are listed in Table 2. A distinction is made between the oil properties and reservoir characteristics that are required. Generally, polymer flooding is applicable in low-to-medium viscosity oils; depth is not a major consideration, except at great depths the higher temperature may present problems in the degradation or consumption of the polymer.

B. Fluid Analyses

A complete water analysis is important to determine the effects of dissolved ions on the viscosity achieved with polymer solutions or to ascertain any potential water problems such as scale or corrosion that may result when EOR processes are implemented. Water viscosity and density are also measured; oil viscosity and density are measured as well. Viscosity and density measurements should be performed at the appropriate temperature of the reservoir under study.

C. Preliminary Core Testing

Routine core analyses, such as porosity, permeability, relative permeabilities, capillary pressure, and waterflood susceptibility tests are normally done by service companies which specialize in these tests. Specialized core tests, such as thin sections or scanning electron microscopy, are available to evaluate the relationship between pore structure and the polymer being considered. If required, stimulation or injectivity improvement measures can be recommended.

D. Polymer Tests

The desirability of adding polymers is determined by evaluating all available data to assess the performance of normal waterflooding. Any problems such as adverse viscosity ratios or large permeability variations should be identified. If the results of this study indicate that mobility control of the waterflood is warranted, laboratory tests are undertaken. While both biopolymers and synthetic polymers are commercially available, many of the following tests are directed toward the application of polyacrylamide polymers which are in widespread use.

1. Viscosity Testing

Based on the permeability of the reservoir, relative permeability data, and the desired level of mobility control, polymers of certain molecular weights are selected for testing. A data base containing results of standarized tests with most of the commercial polymers is available[2,3] to facilitate this selection. Various concentrations of the polymers are dissolved in both the available injection water and in blends of the injection and formation waters (see Fig. 1). Polymer solutions are non-Newtonian at certain shear rates, that is, the viscosity decreases at high shear rates (shear-thinning or pseudoplastic). This shear-thinning behavior is reversible and, if observed in the reservoir, is beneficial in that good injectivity can result from the lower viscosity observed at high shear rates near the injection well. At the lower shear rates encountered some distance from the injector, the polymer solution develops a higher viscosity. In this testing, it is important to consider not only the viscosity of the injected solution, but more importantly the in-situ viscosity that is achieved in the reservoir. Several things can happen that will reduce viscosity when polyacrylamide solutions are injected into a reservoir. Reduction in viscosity as a result of irreversible shear degradation[4] is possible at the injection wellbore if the shear rates or shear stresses are large (see Fig. 2). Once in the reservoir, dilution with formation water or ion exchange with reservoir minerals can cause a reduction in viscosity (see Fig. 3). The injected polymer concentration will need to be sufficiently high to compensate for all viscosity-reducing effects.

2. Flow Behavior of Polyacrylamides in Cores

The flow behavior of polyacrylamide solutions in core samples depends on a number of variables, including nature of rock (especially permeability), type of water, polymer concentration, polymer molecular weight, and flow rate. The resistance to flow or reduction in water mobility that is caused by the presence of polymer is referred to as the resistance factor. At low velocities, resistance factors decrease as the interstitial velocity is increased--this reflects the shear-thinning nature of the solution. Under these conditions, the resistance factor is generally some factor higher than the viscosity measured in a standard rotational viscometer. When the velocity reaches about 10-40 ft/day, the resistance factor increases as the velocity is increased--this shear-thickening behavior reflects the viscoelastic nature of the polymer. Viscoelasticity results when the flexible polymer molecule is deformed and the flow rate is sufficiently high that the molecule cannot return to its original conformation. This behavior requires an additional pressure drop to push the molecule through the rock. The viscoelastic trend will continue until mechanical degradation is encountered at very high flow rates (see Fig. 4). When degradation occurs, the resistance factor decreases with additional increases in flow rate as a result of increased degradation at higher velocities. This mechanical (also called shear) degradation, caused by a fragmentation of some of the high molecular weight polymer molecules, results in a permanent loss in viscosity of the polymer solution.[4] Since this complex behavior cannot be represented with a single core in the laboratory, different cores are employed to simulate the conditions encountered in the field.

3. Injectivity and Mechanical Degradation

Small core plugs are used to simulate conditions that could exist in the immediate vicinity of an injection well.[2] After the polymer solution being tested is passed through a 325-mesh screen to remove debris or insolubles, it is injected through an injectivity core at rates that might be encountered around the wellbore. Initially, the rates are modest so that shear degradation is minimal. If the polymer is unable to propagate through the core without plugging, it is eliminated from consideration. If the polymer does not plug the injectivity core, injection rates are increased in a stepwise fashion until maximum shear rates are obtained.

One way of monitoring mechanical degradation is to determine the reduction in viscosity of the polymer solution as a result of passage through a small core plug at high rate. Another standard test of the polymer solution is measurement of the time required for the solution to pass through a series of five 100-mesh screens. The ratio of the polymer flow time to the flow time of an equal volume of water is referred to as the Screen Factor which measures properties related to the viscoelastic nature of the polymer solution.[5] Whereas viscosities of polymer solution are influenced by the average molecular weight, screen factors are influenced to a greater degree by the higher molecular weight fractions of the polymer molecules.[6] A reduction in screen factor as a result of high-rate flow through cores can be interpreted as a loss in some of the higher molecular weight fractions of the polymer.[6]

Mobility control tests can consist of determining resistance factors at low flow rates with solutions of polymer that were previously injected through other cores at high rates.[2] Irreversible mechanical degradation is indicated if the resistance factor in the low rate core is reduced by the high-rate flow conditions in the first core. However, these tests are time-consuming and costly. With the injectivity core, information regarding mobility control in the reservoir or the amount of polymer retention will not be obtained; however, a number of polymers can be evaluated in a relatively short period of time. Polymers that pass this test are then further tested in the more time-consuming tests conducted at reservoir rates.

4. Mobility Control Tests

After about 50 pore volumes of polymer solution have been flowed at a modest rate through the injectivity core and discarded, a large volume of effluent is then collected for subsequent mobility control tests. Since in field applications the bulk of the reservoir is contacted by polymer solution filtered in this manner, this procedure should more closely simulate field conditions.[2]

A larger core is used to measure the reduction in mobility caused by the polymer solutions. The pressure drop across the core is related to the flow rate, the solution viscosity, and the permeability of the rock. All mobility tests are performed at a constant flow rate in the range of expected reservoir flow rates (~1 ft/day), so that the pressure drop is a measure of the ratio of permeability to viscosity, and is thus a measure of effective viscosity. Two measurements are of particular interest: the polymer resistance factor, which compares the mobility of water to that of the polymer solution; and the residual resistance factor, which compares the mobility of water before and after polymer flooding. Higher values of polymer resistance factor correspond to greater mobility control, and higher values of residual resistance factor indicate a permanent or long-term effect on the rock permeability, probably caused by adsorption or entrapment of polymer.

5. Oil Recovery Tests

If requested, oil recovery tests can be conducted to compare a polymer flood to a standard waterflood. However, in most cases the information obtained from these tests can not be directly related to field performance, thus the costs of performing the tests may not be warranted.

6. Polymer Retention

Retention of polymer in a reservoir can result from adsorption, entrapment, or, with improper application, physical plugging. Polymer retention tests are usually performed after a standard waterflood (at residual oil saturation) or during a polymer flood oil recovery test. If polymer retention tests are conducted with only water initially present in the core, a higher level of retention will result from the increased surface area available to the polymer solution in the absence of oil. Effluent samples from the core are collected both during the polymer injection and a subsequent water flush. These samples are analyzed for polymer content. From a material balance, the amount of polymer retained in the core is calculated. Excessive retention will increase the amount of polymer that must be added to achieve the desired mobility control. The level of polymer retained in a reservoir depends on a number of variables: permeability of the rock, surface area, nature of the reservoir rock (sandstone, carbonate, minerals, or clays), nature of the solvent for the polymer (salinity and hardness), molecular weight of the polymer, ionic charge on the polymer, and the volume of porosity that is not accessible to the flow of polymer solution. Polymer retention levels often range from less than 100 lbs/acre-ft to several hundred lbs/acre-ft.

II. Field Design

Field-derived polymer flood design parameters are used for a production forecast.[7] Laboratory design work is confirmed by field experiments or, in the event that cores are not available, field experiments are the only means of acquiring the information needed for a production forecast.

A. In-Situ Oil and Water Mobilities

Initially, oil mobility is determined via a pressure buildup test on a producing well. Frequently, this is accomplished with fluid level measurements. Reservoir pressure and wellbore damage or fractures are also reported with the pressure buildup test analysis.

Water mobility is calculated from a pressure falloff test of an injection well. This test requires a bottomhole pressure bomb if a well goes immediately on a vacuum. Reservoir pressure and wellbore damage or fractures also result from the analyses.

Both the buildup and falloff transient tests require frequent, accurate measurement of bottomhole pressure and time, particularly during the first hour the well is shut in. Occasionally, multiwell interference tests are performed to predict the areal direction of fluid flow. Multiwell tests are usually done in fields with dense well spacing.

Once the oil and water mobilities are known, calculation of the mobility ratio provides a ready means of estimating performance improvements with polymer. The laboratory work provides polymer viscosity versus concentration data, as well as estimates of polymer retention and mobility.

B. Polymer Retention

Polymer retention can be confirmed or calculated in the absence of cores by a field pump-in/pump-out experiment. A small volume of polymer solution, enough to reach ~5 ft from the wellbore, is pumped into the well. The polymer is tagged with a tracer to account for drift. Following a shut-in period, the tracer-tagged polymer solution is swabbed from the well. Polymer retention is calculated by material balance. Obviously, this field experiment must be performed on a well free of prior polymer injection. If care is taken during the production phase of this experiment, polymer degradation (both chemical and mechanical), can be calculated by measuring the before and after fluid viscosities and accounting for retention.

C. In-Situ Polymer Viscosity

In-situ polymer viscosity is determined by injecting a slug of polymer and following with a falloff test. Three slugs of different viscosities are normally injected in order to develop a correlation between surface viscosity and in-situ viscosity.[7,8] The viscosity correlation is used to estimate polymer concentration required for any desired mobility ratio and, of course, the resulting production forecast. From an analysis of this type of experiment, wellbore skin damage and the effect of viscosity on injection rate can be assessed. Polymer slug size depends on the results of the prior pressure falloff test with water, but the time required for polymer injection is generally of two weeks duration.

D. Flow Control

If more than a 100 psi pressure drop across an injection choke is required to control the flow of water, then polymer flow control with coiled tubing should be investigated in order to minimize mechanical shear degradation. Field experiments with various sizes of copper tubing and plant injection equipment can be run prior to full-scale polymer injection, and the resulting data used to design proper tubing configuration for all injection wells.

III. Production Forecasts

When performing economic studies used to optimize polymer slug size and concentration, production forecasts are required. The forecast must reflect the effect of water injection rate on oil production rate as well as the ultimate recovery. An economic study includes the time value of money; therefore, production rate is all important.

Lower mobility ratios improve both areal and vertical sweep efficiencies. Therefore, a reduced mobility ratio resulting from polymer injection yields improvements in displacement, areal, and vertical sweep efficiencies.

A convenient forecasting method based on fluid mobilities is possible. The method utilizes the equations of Buckley-Leverett,[9] and Welge[10] to describe displacement efficiency (see Fig. 5). This 100% displacement efficiency is then reduced according to areal sweep correlations[11] and vertical sweep correlations.[12-14] Thus, a forecast based solely on fluid saturations and mobilities can be obtained.

The method begins with forecasting waterflood performance in order to provide a reference for incremental polymer flood oil production. Once a satisfactory waterflood prediction is accomplished, polymer mobility characteristics are substituted for water, and the incremental oil is calculated. Since polymer mobility is dependent on polymer concentration, the amount used versus the incremental oil produced can be studied. The incremental oil resulting from various polymer slug sizes (slug size requires retention data) is also evaluated.

Production rates include the effect of reduced water mobility on injection rates. Injection rates are estimated with modified forms of the Darcy equation, and fluid mobilities are estimated from laboratory data or field injectivity tests. Since the Darcy equation demonstrates that the injectivity index is proportional to the injected fluid mobility, increased viscosity results in decreased injection rates. In some instances, injectivity can be increased substantially by reducing oil saturations a few feet out from injection wellbores.[15]

IV. Project Start-up and Monitoring

Following a decision to proceed from an evaluation mode to implementing a commercial project, time must be spent on development of product specifications and project start-up. The chemical supplier and the operator agree to specifications which can be checked in the field at the time of product delivery. Project start-up includes measurement of injection fluid quality to ensure that design parameters are met. At the same time, operating personnel are trained in mixing chemicals, monitoring fluid quality, and testing for product specifications.

During project start-up, tracers can be injected and producing well samples collected for background analyses. Ongoing project monitoring includes testing producing well samples for chemical or tracer breakthrough. Injection and production records can be maintained on a dimensionless time basis (pore volumes injected) in order to compare actual performance to that forecasted. Thorough record keeping facilitates timely well stimulations or changes in the chemical design.

CONCLUDING REMARKS

Polymer floods, which can be undertaken by companies of any size, are more complicated than waterfloods, but are less complicated than other methods of enhanced oil recovery. The key to a successful polymer flood is to evaluate a reservoir properly and to provide the engineering necessary to minimize risks and maximize profit. Provided reservoir conditions are amenable, polymer flooding can be successful if a project is properly designed, implemented, and monitored.

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Table 1
An Outline of the Requirements for the Proper Implementation of a Polymer Flood

Phase 1: Preliminary Feasibility Study
- A. Analysis of Reservoir Fluids
- B. Review Waterflood Performance
  1. Oil Recovery
  2. Reserve Estimates
  3. Injectivity
  4. Transient Tests
- C. Reservoir and Fluid Screening
- D. Laboratory Work
  1. Polymer Viscosities
  2. Injectivity Cores

Phase 2: Design Phase
- A. Additional Laboratory Work
  1. Rock-Fluid Interactions
  2. Polymer Shear Tests
  3. Polymer Mobility Tests
  4. Polymer Retention Tests
  5. Polymer Stability Tests
- B. Engineering Estimates
  1. Waterflood Performance
  2. Polymer Flood Performance
  3. Chemical Requirements
  4. Chemical and Equipment Costs
- C. Field Testing
  1. Dynamic Retention
  2. Injectivity Test
  3. In-Situ Viscosity
  4. Mechanical Degradation
  5. Evaluate Flow Control Devices
- D. Computer Simulation*
  1. Optimize Polymer Concentration and Slug Size
  2. Economic Evaluation
- E. Facilities Design
  1. Chemical Handling and Storage
  2. Mixing
  3. Hydration Tanks
  4. Flow Control
  5. Sampling Points

Phase 3: Project Start-Up and Monitoring
- A. Logistics
- B. Product Specifications
- C. Training of Field Personnel
- D. Monitor Performance

*Optional

Table 2
Screening Criteria for Polymer Flooding

Description

The objective of polymer flooding is to provide better displacement and volumetric sweep efficiencies during a waterflood. Polymer augmented waterflooding consists of adding water soluble polymers to the water before it is injected into the reservoir. Low concentrations (often 250-2000 mg/l) of certain synthetic or biopolymers are used; properly sized treatments may require 15-22% reservoir PV.

Mechanisms

Polymers improve recovery by:
- increasing the viscosity of water
- decreasing the mobility of water
- contacting a larger volume of the reservoir

TECHNICAL SCREENING GUIDES

Crude Oil	
Gravity	> 25° API
Viscosity	< 150 cp (preferably < 100)
Composition	Not critical
Reservoir	
Oil Saturation	> 10% PV mobile oil
Type of Formation	Sandstones preferred, but can be used in carbonates
Net Thickness	Not critical
Average Permeability	> 10 md (as low as 3 md in some cases)
Depth	< about 9000 ft (see Temperature)
Temperature	< 200°F to minimize degradation

Limitations

If oil viscosities are high, a higher polymer concentration i%s needed to achieve the desired mobility control. Results are normally better if the polymer flood is started before the water-oil ratio becomes excessively high. Clays increase polymer adsorption. Some heterogeneities are acceptable, but for conventional polymer flooding, reservoirs with extensive fractures should be avoided. If fractures are present, the crosslinked or gelled polymer techniques may be applicable.

Problems

Lower injectivity than with water can adversely affect oil production rate in the early stages of the polymer flood. Acrylamide-type polymers lose viscosity due to shear degradation, or increases in salinity and divalent ions. Xanthan gum polymers cost more, are subject to microbial degradation, and may have a greater potential for wellbore plugging.

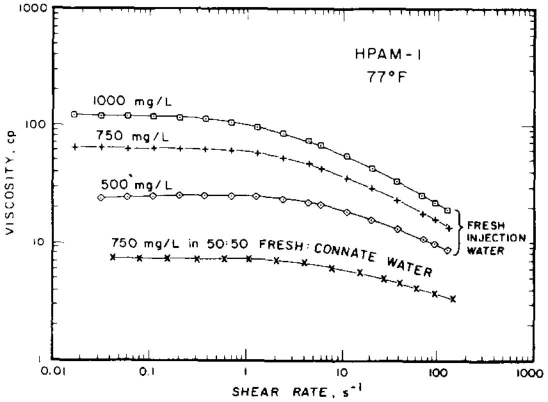

Figure 1—Viscosities of polymer solutions

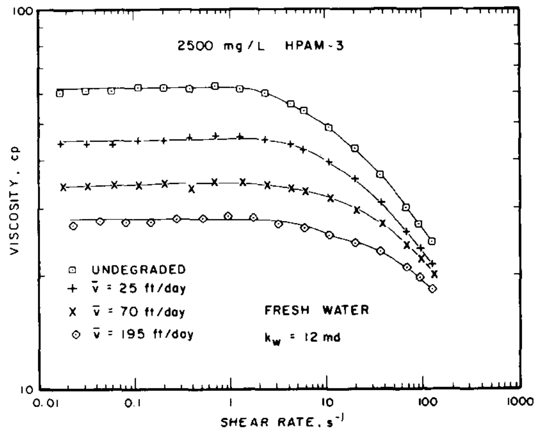

Figure 2—Viscosity of polymer solution sheared at several velocities in a carbonate core

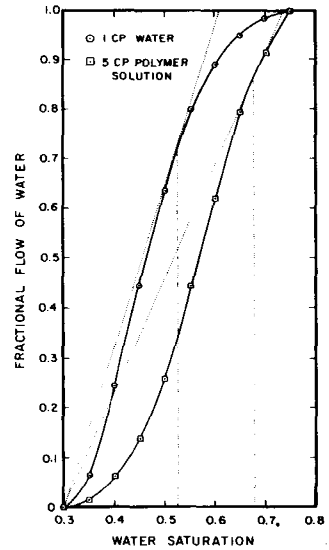

Figure 5—Displacement efficiency of water and a polymer solution

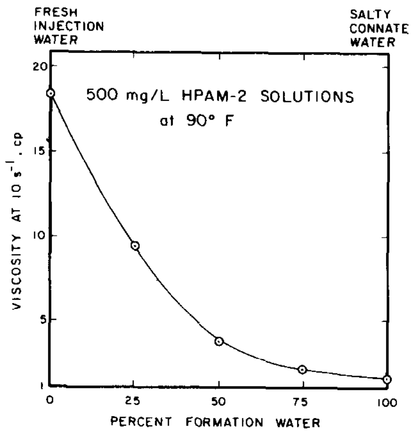

Figure 3—Reduction in polymer solution viscosity resulting from mixing with connate water

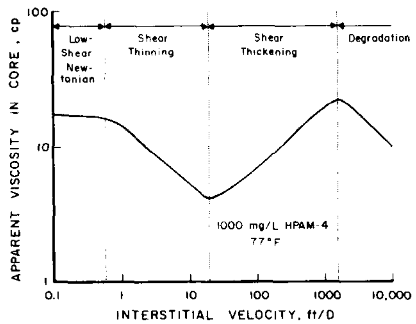

Figure 4—Effect of velocity on flow resistance of polyacrylamide solution in a sandstone core