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Research Article

Effects of Polymer Injectivity Concentration on Time-Variation Relative Permeability

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ABSTRACT

Polymer flooding is a set Enhance Oil Recovery (EOR) which is considered as best candidate for the mature hydrocarbon reservoir. Many polymer flooding projects been carried on successfully around the world, but there are still non understood effects of polymer flooding. One of the main effects is the polymer injectivity loss or polymer plugging which is the major affecting factor on the reservoir. The increase in polymer viscosity injection is a major influence for polymer injectivity reduction, as well others mechanism such as; mechanical, debris, permeability reduction, and water quality.

In this research some effects of polymer injectivity concentration time-variation are investigated as following:

Polymer entrapment during polymer injectivity, left debris in the reservoir, polymer rheology, mechanical degradation, and permeability reduction are the main effecting factors.

When the liquid rate decreased in function of polymer injectivity time-variation phase change concentration, production rate has improved in function of time-variation phase change.

The dynamic change of reservoir in each iteration step is updated to achieve stable, reliable and continuous characterization of reservoir permeability changes, and objectively reflects the changes in the permeability of long term polymer flooding reservoirs and the effects of oil-water motion laws. The stability and reliability of the reservoir numerical results are guaranteed.

Keywords: Relative permeability; Injectivity; Plugging; Time-variation; Polymer flooding

INTRODUCTION

Polymer flooding is a mature technique with over 40 years of commercial application. Polymers are used in several improved/ Enhanced Oil Recovery (EOR) processes for maintaining the mobility control of the injected fluid front and for increasing the recovery [1]. Recently, there has been growing interest in the application of this technique to heavy oil reservoirs. Based on the EOR survey, there are five case studies (Bohai Bay, Offshore China; East Bodo and Pelican Lake, Canada; Tambaredjo, Suriname; Bati Raman, Turkey; Marmul, Oman) on the application of polymer flooding for heavy oil recovery. Water soluble polymers are well suited for increasing the injectant viscosity and thus the ultimate recovery [1,2]. According to our knowledge, most of the previous core flood studies on polymer flow through porous media tested the polymer concentrations up to a maximum of 1500 ppm. stressed the importance of high polymer concentrations for increasing the oil recovery [3]. They also showed that recovery improves steadily with increase in polymer concentrations from 500 to 5000 ppm. Viscosity is a strong function of polymer concentration [4]. Above critical overlap concentration the polymer solution viscosity increases drastically with concentration. The viscous nature of these polymer solutions reduces the injectivity and delay oil production. Apart from the viscosity, polymer retention in porous media due to various mechanisms such as adsorption onto rock surface, mechanical entrapment and hydrodynamic retention were found to be potential causes for reduction in injectivity [5-7]. conducted experiments on Berea core samples with wide variety of EOR polymers to assess their injectivity characteristics [8]. He emphasized three main properties that affect polymer injectivity: (1) Debris in the polymer, (2) Rheology in porous media, (3) Mechanical degradation. He found that in the absence of face plugging the viscous nature of polymer solutions cause injectivity losses. Ineffective hydration, microgels and debris in the polymer

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can cause face plugging at the inlet of the core [8]. Developed a modified filter test for higher solution throughputs in 100-600 mD Berea sandstones with porosity of 21%. The effect of face-plugging was also observed in the Coalinga field test in a sandstone formation with permeability around 50-480 mD [9]. It was also found that extensive filtration of polymer prior to laboratory experiments without the loss of polymer solution viscosity can retain the injectivity to some extent. It was also observed that this varies with the permeability of the formation. Also found face plugging in core floods having a permeability of 200-400 mD with unfiltered polymer solutions [10]. Conducted experiments with unfiltered Xanthan polymer solutions with concentrations around 400 to 1000 ppm [11]. These are polymer/brine displacement studies in stratified cores with permeabilities in between 450-1000 mD. From the study it was found that unfiltered Xanthan solutions do not cause permanent plugging of the porous medium especially in high permeability layers.

In the Cartesian coordinate as the size of a well block increases, velocity smears, and thus shear rate and consequently polymer viscosity is erroneously calculated [12,13]. Therefore, for the field applications, the transport equation is solved in the radial coordinate to avoid using well model. Very small grid blocks were used to minimize the shear-rate errors associated with the grid block size.

The physical absorption of polymer is modeled with Langmuir isotherm equation. Polymer absorption can reduce the effective permeability [14].

The permeability reduction factor is not significant for many polymers such as xanthan gum or when the formation permeability is high [15].

Lei et al found that the concentration is the main factor affecting the relative permeability of the polymer. Concentration is the main factor affecting the difference between polymer flooding permeability and water flooding permeability. The greater the concentration of the polymer solution is, the lower the relative water permeability value.

Yang obtained that the increase of the concentration of the polymer solution makes the relative permeability phase curve shifting to the right; under the same water saturation, the relative permeability of the polymer solution decreases with increasing concentration, and the relative permeability of the oil phase is less affected.

Injectivity declines with respect to time due to the fact that viscosity of polymeric fluid changes during flooding process. There are a couple of mitigation actions to prevent injectivity declines including alteration of injection rate, polymer solution concentration or fracturing injection [16]. Injection under fracturing condition is a useful action that initiates polymer flood above formation parting pressure (FPP), which creates induced fractures contributing to injectivity increment. Calculations of injectivity for both below and above FFP were studied by [17,18].

In some field projects under polymer flooding, it was observed that actual polymer injectivity was higher than that of the expected one, even higher than water injectivity [19-20]. A likely reason is that injection pressure greater than the formation fracturing pressure would be more possible during polymer flooding [21], and consequently, induced fractures are generated and propagated during polymer flooding [22]. Fracture size and direction have an important effect on Waterflooding and enhancement of oil recovery, especially for those reservoirs containing multilayered formations [23-27].

The objective of this research are stated as following:

- Give a vital idea about polymer plugging phenomena and it is effects during polymer injectivity.
- Effects of polymer concentration solution on relative permeability.
- Improving the sweep efficiency with the application of polymer flooding for enhancing the reservoir production

METHODS

During the polymer flooding moment, the changement of polymer concentration solution will affect also others parameter such as relative permeability curve of oil and water of the whole reservoir in function of time. This changement of curve infiltration will surely influence the distribution of residual oil after the polymer flooding process of this reservoir. The objective of the present technical roadmap supplies a numerical simulation method for deliberating the transition phase of polymer flooding reservoir, which is rational, stable and simple in operation for the reason of refraining from the inadequacy in the preliminary art.

For the realization of the operational flow, for the meaning of this compilation and the necessity of the present realization, an implementation of conceptual model is taken in consideration.

A numerical simulation model of the reservoir was established with a grid size of: 11 × 11 × 5, the grid step size is 50 × 50 × 1, the plane direction permeability is 700 mD, and the longitudinal permeability was 30 mD, Four (4) injector well located in the model corner layer, while 1 producer well placed in the middle.

The model simulation based on 20 years, first relying on natural energy for a period of 1 year, then water injection development plan placed for a period of 9 years, within reaching 10 years' polymer is applied for the rest of reservoir simulation scheme.

Eclipse software approached to simulate the time-variation relative permeability by the following technical method.

Build a numerical simulation model of the polymer flooding reservoir, introducing two (2) phase infiltration, one is the infiltration curve 1 (IC1) when the concentration of polymer at 0, and another one represent the concentration of the polymer solution. For the maximum phase permeability curve 2 (IC2), define a weight function F as an interpolation parameter (a function of the concentration of the polymer solution) (Table 1).

Table 1: Model description and properties.

Characteristic	Value	Units
Grid size	11 × 11 × 5	ft.
Grid step size	50 × 50 × 1	ft.
The plan direction permeability	700	mD
Longitudinal permeability	30	mD
Porosity	25	Fraction

Through the full implicit method, in each iterative calculation process of the reservoir numerical simulation, first to compute the saturation and polymer solution concentration data of each grid block recovered from the previous iteration step.

At any polymer solution concentration m, the endpoint values of the two curves input in T1 are interpolated by F to obtain two new endpoint values A and B, and two new phase infiltration curves IC3 and IC4 are obtained.

By reading the fluid saturation value (St) of each grid in the model, using the saturation value to obtain two points C and D on the new phase infiltration curves IC3 and IC4.

Using F to interpolate point C and point D to obtain point E, the relative permeability value corresponding to point E is the value obtained, and then obtain a corresponding phase permeability curve corresponding to the concentration of the polymer solution m.

After obtaining the modified reservoir permeability and relative permeability curves, calculate the saturation and concentration of the iteration step, and then perform the cycle calculation of the next time step.

Wherein, in step T1, by inputting two phase infiltration curves (the concentration of the polymer solution is 0/maximum) as the basic phase infiltration curve, it is required for subsequent interpolation calculation, and it is not necessary to define a plurality of phase infiltration curves at the same time.

The weighting function F is used as an interpolation parameter, and the two basic phase infiltration curves input in step T1 are interpolated to obtain a phase infiltration curve at a concentration m of any polymer solution, and a reservoir is established. Permeability as a function of polymer solution concentration, quantitatively characterizes the range of permeability changes at different polymer solution concentrations, from updating the permeability data field of the grid block at different polymer solution concentrations throughout the iterative calculation process, this makes the entire simulated polymer flooding numerical calculation process more in line with the actual polymer flooding process (Figure 1).

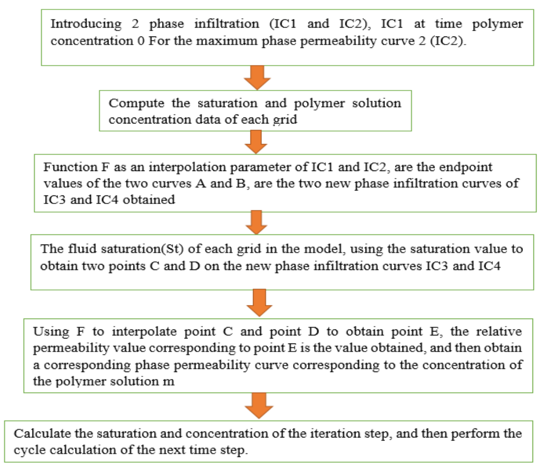

Figure 1: Time-variation technical method structure

RESULTS AND DISCUSSION

Polymer Shear thinning: we can observe on the figure that when the water phase flow velocity increase, the shear factor decrease. Shear decrease could cause the shear thinning due to polymer degradation.

Polymer viscosity function: when the polymer concentration increases, the viscosity of the polymer also increase.

Polymer adsorption function: when the polymer saturated concentration decrease, the concentration of polymer increase in function of time.

Water/oil saturation functions versus permeability curve: shows the basic infiltration curves of the input with polymer concentration. When the permeability relative of oil in function of water saturation decrease, then the permeability relative of water in function of water saturation increase.

During the computing process, the reservoir permeability curves change in function of the polymer concentration. We could observe that on the phase infiltration curve when the concentration of the polymer solution is maximum (0.75 above) it causes a shifting to the right.

Concentration of Polymer adsorption: surrounding the injector wells polymer is highly absorbed compared the producer well location polymer concentration adsorption is less.

Field Water Cut (FWCT): water cut has reached 0.94 in 2009-01-12 then with the application of polymer injectivity in 2010-01-01 dropped, water cut decreased to it is lowest 0.75 in 2012-02-01. Finally Water cut raised again slowly till it has reached 0.97 in 2020-01-01.

Field Production Rate (FPR): field production rate is 115 BARSA decreased to it is lowest 20 BARSA for 300 days then slowly started increasing and it has reached 83 BARSA in 4500 days then experienced a high rate with the application of polymer injection to 125 BARSA in 5100 days till 5989 days then dropped in 6000 days but the rate is stable even with the drop on 112 BARSA.

Field Oil Production Rate (FOPR): field oil production rate started on 60 sm^3/day dropped to it is lowest 0 sm^3/day for 300 days then reached to it is highest rate of 120 sm^3/day for 800 days. Then the rate started decreasing till it has reached 14 sm^3/day in 3750 days but the application of polymer increased to 28 sm^3/day and dropped in 5000 days.

Field Liquid Production Rate (FLPR): the starting liquid production rate is 60 sm^3/day dropped to 0 sm^3/day for 300 days then raisedtill it has reached 120 sm^3/day in 500 days. Liquid rate was stabletill when polymer has been introduced the rate dropped to 116 sm^3/day in 4775 days and raised little bit in 5000 days but still experiencing some decrease till in 5800 days recovered back to therate of 120 sm^3/day for the rest of reservoir life.

Based on the numerical simulation method for considering the phase change of the polymer flooding reservoir in the present invention, a new phase infiltration curve is calculated according to the concentration of the polymer solution is established. The dynamic change of reservoir in each iteration step is updated to achieve stable, reliable and continuous characterization of reservoir permeability changes, and objectively reflects the changes in the permeability of long term polymer flooding reservoirs and the effects of oil-water motion laws. The stability and reliability of the reservoir numerical results are guaranteed.

The present invention has been described in detail in the above description, and it is not to be built as limiting the scope of the invention.

With the application of polymer injectivity concentration caused the field production rate to decrease in function of time-variation phase change due to the polymer degradation which caused entrapment. While the liquid rate decreased in function of polymer injectivity time-variation phase change concentration, but the production rate raise in function of time variation phase change with the application of polymer injection in the reservoir.

CONCLUSION

In conclusion, the present invention has been described in the above-described preferred to carried out, but it should be understood that various changes and modifications may be made by those skilled in the art unless such changes and modifications depart from the scope of the present invention. Within the scope of protection of the present invention. For understanding polymer injectivity decline in function of time-variation the following parameters have to be investigated: Polymer entrapment during polymer injectivity, left debris in the reservoir, polymer rheology, mechanical degradation are the main effecting factors.

The relative permeability is not highly effected with the increase of polymer concentration injection in function of time-variation polymer injectivity concentration enhance the oil recovery in function of time-variation.

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