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Numerical simulation of surfactant–polymer coreflooding experiments for carbonates

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ABSTRACT

Surfactant–polymer (SP) flooding is of particular interest in recent years due to its synergetic effects of interfacial tension reduction and mobility control with minimal side effects. This work focuses on constructing an SP simulation model using laboratory data and validating it by matching coreflooding results. A series of SP coreflooding experiments were performed in carbonate cores under reservoir conditions. Chemical injection was implemented in tertiary mode with varying slug sizes and concentrations. The coreflooding results show significant oil recovery potential for SP formulations under the conditions investigated. The base SP flood resulted in 23.4% incremental recovery after waterflooding with the polymer and surfactant contributions being about the same. The results also demonstrate the effects of surfactant slug-size and concentration on the recovery performance. Using UTCHEM the input parameters, necessary to predict incremental recoveries, were investigated. A general SP simulation model was initiated, in which polymer viscosity dependence on concentration and salinity was established in the laboratory; surfactant phase behavior parameters were generated from test-tube results; and oil desaturation was based on additional coreflooding. After matching water and polymer flooding results, the surfactant simulation model was tuned through history matching the performance of a series of SP corefloods. A subsequent sensitivity analysis establishes the confidence level of the input parameters. The sensitivity analysis also highlights the significance of IFT reduction. Finally, we numerically investigated the optimum chemical formulation. Optimization runs were performed under a fixed chemical consumption condition. The results support the optimality of previously selected slug sizes while suggesting the potential benefit of increasing the polymer concentration at the expense of surfactant concentration.

1. Introduction

Surfactant–polymer (SP) flooding is of particular interest in recent years due to its synergetic effects of interfacial tension (IFT) reduction and mobility control with minimal side effects (Wang et al., 2010; Zhu et al., 2010). The addition of alkalis in ASP flooding, while able to supplement IFT reduction – through the in-situ generation of soap and reduction of surfactant consumption (Lake, 1989; Pope, 2007) – can result into serious scale problems (Krumrine et al., 1985; Bataweel and Nasr-El-Din, 2011; Karazincir et al., 2011). Whether SP or ASP is to be implemented, the ability to reasonably predict the enhanced oil recovery (EOR) performance under various injection scenarios is paramount for the successful design and application of chemical EOR. Poor scaleup is one of the underlying reasons behind the limited success of Chemical EOR in the 20th century (Thomas, 2006). In this work, we focus on generating a predictive SP simulation model that matches SP coreflooding observations. This represents the first step toward successful field scaleup.

Actually, the number of studies that have looked at generating and calibrating such models using coreflood experiments underlines the importance of this step. One of the earliest studies was part of the Bell Creek Micellar–Polymer demonstration pilot (Todd et al., 1978). The purpose of this work was to generate predictive SP models, which were later used in a pilot-scale simulation study for the evaluation of two competing chemical injection schemes. In this study, Todd et al. (1978) have used a multicomponent two-phase simulator to construct an SP model for two different chemical injection schemes based on a suite of coreflood experiments. Gupta (1982) has performed a similar exercise in an effort to better interpret the observed pilot performance at the Sloss field. For this purpose, Gupta (1982) has used a two phase-model to history match SP coreflood experiments performed in Berea cores. Huh et al. (1990) also used a surfactant model – that was initially calibrated against two surfactant polymer corefloods in Berea and Loudon cores – to evaluate and interpret the

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Nomenclature

C_{pw}	polymer concentration, M/M, wt%
C_{ad-c}	adsorbed concentration of component c, L^3/L^3 or M/M, vol/volw or wt%
C_{bec}	brine effective salinity for component c, dimensionless
C_{aa}	anions concentration, M/L^3, meq/ml
C_{da}	divalent anions concentration, M/L^3, meq/ml
C_{da}	water component concentration in aqueous phase, L^3/L^3
R	solubilization ratio, L^3/L^3
μ_w	pure water viscosity, $ML^{-1}T^{-1}$, mPa s
μ_{aq}	aqueous phase viscosity, $ML^{-1}T^{-1}$, mPa s
σ	interfacial tension, $ML^{-1}T^{-2}$, mN/m
S_{pr}*	normalized residual saturation of phase p, dimensionless
N_{ca}	capillary number, dimensionless

performance of a series of surfactant field pilots performed in the Loudon field. In another study, Vargo et al. (2000) have used an experimentally-calibrated model to history match the Cambridge Minnelusa ASP flood and predict its future performance. Vargo et al. (2000) were probably the first of such studies that used a commercially available simulator. Their model was built using the chemical option of GCOMP and it was calibrated through history matching the performance of radial floods in sandpacks. Similarly, Hernandez et al. (2003) used radial flooding experiments performed in sandpacks to calibrate a GCOMP chemical model. The calibrated model was then used to evaluate the potential of ASP flooding the La Salina field. Pandey et al. (2008) have also used radial flooding experiments but of actual cores, that were ~10 cm in diameter and 5 cm thick, to generate and fine-tune a chemical model built using CMG-STARS. The fine-tuned model was later used to evaluate and design the Mangala field pilot. The most recent study was by Parracello et al. (2013). The purpose of which was to evaluate a potential pilot in an on-shore sandstone reservoir in Africa. Parracello et al. (2013) SP model was validated through history matching of three coreflood experiments.

In most of those studies, satisfactory history matches were obtained; however, few points are worth highlighting. Compared to experimental results, Todd et al. (1978) numerical predictions of oil cut and recovery were satisfactory but not great. The degree of correspondence between predictions and observations for the different experiments varied from being excellent to poor. Gupta (1982) results show excellent agreement with experimental observations in terms of the final oil saturation (i.e. ultimate recovery) for a series of displacement experiments conducted at varying water salinities. A good match for the oil production cut was also obtained; however, the model predicted a longer-tailed production profile, which was experimentally observed but not to a similar extent. To the contrary, Camilleri et al. (1987) also history matched Gupta's (1982) experiment but could not match the production tail. Furthermore, Pandey et al. (2008) numerical predictions were excellent for the polymer corefloods, but for the ASP corefloods predictions were of lesser quality. In the last study by Parracello et al. (2013), the performance of continuous chemical injection was well-matched, but recovery predictions for slug injection were poor. Finally, we should note that various other studies have looked at history matching chemical coreflooding experiments but with the explicit purpose of validating a new, an improved, or even a simplified chemical flooding simulator (Carney and Finlayson, 1982; Van Quy and Labrid, 1983; Camilleri et al., 1987; Mohammadi et al., 2009; Douarche et al., 2011; Karpan et al., 2011; Farajzadeh et al., 2012; Delshad et al., 2013).

In this work, we use the University of Texas Chemical Flood Simulator: UTCHEM (PGE, 2007). The model is built using laboratory data and later calibrated and validated through history matching oil-displacement coreflooding results. Compared to the similar works in the literature, the SP model developed in this paper is tested and calibrated not only against a single SP flood but against a series of SP floods performed in cores of the same formation but with different injection conditions. Consequently, the resulted SP model should be more unique and more robust. Though compared to work in the literature (Camilleri et al., 1987; Huh et al., 1990; Pandey et al., 2008; Mohammadi et al., 2009) which looked at history matching recoveries, pressures, and effluent profiles, in this paper we focus solely on the successful prediction of recoveries for a carbonate reservoir.

The paper first presents the results for a series of SP corefloods performed in a carbonate sample under reservoir conditions. We then describe the construction of the initial SP simulation model using laboratory data. We present the results of a detailed numerical investigation in which we (1) calibrate our SP simulation model and (2) study the sensitivity of the simulation results. Finally, we discuss the numerical optimization of the chemical formulation.

2. Description of coreflooding data

A series of SP coreflooding experiments were performed in carbonate cores under reservoir conditions: temperature of 90 °C and pore pressure of 21 MPa. In each, a chemical slug was injected in tertiary mode. For the base SP flood (CF-1), 0.4 pore-volumes (PV) of SP were injected followed by 0.2 PVs of polymer injection. Both surfactant and polymer concentrations, in the base coreflood, were 0.2 wt%. Oil and brine used were representative of the field fluids (Table 1). Compared to the base case, in the remaining corefloods the chemical slug was manipulated to investigate/factor-out its effect. In corefloods 2–5, SP slug size, surfactant concentration, brine salinity, and polymer injection effects were investigated, correspondingly. Table 2 lists the properties and injection sequence for the five corefloods.

The results of those corefloods are listed in Table 2. The results demonstrate the potential of SP flooding; coreflooding results show significant oil recovery potential for the SP formulation under the conditions investigated. The base SP flood (CF-1) resulted in a post-waterflooding incremental recovery of 23.4% original oil in place (OOIP). The results also demonstrate the effects of polymer injection, surfactant concentration, SP slug size, and brine salinity on the recovery performance (Fig. 1). The polymer injection coreflood (CF-5) demonstrates the magnitude of recovery enhancement

Table 1
Properties of oil and brine used in coreflooding experiments.

	Oil	*Brine*
Viscosity (μ) @ 90 °C (mPa s)	0.85	0.34
Total dissolved solids (TDS) (ppm)	–	84,715
Anions (C_{aa}) (meq/ml)	–	1.47
Divalent cations (C_{da}) (meq/ml)	–	0.493