**Exploitation and Optimization of Reservoir Performance in
Hunton Formation, Oklahoma**

QUARTERLY TECHNICAL PROGRESS REPORT

Submitted by

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Abstract

West Carney field – one of the newest fields discovered in Oklahoma – exhibits many unique production characteristics. These characteristics include:

- 1) decreasing water-oil ratio;
- 2) decreasing gas-oil ratio followed by an increase;
- 3) poor prediction capability of the reserves based on the log data; and
- 4) low geological connectivity but high hydrodynamic connectivity.

The purpose of this investigation is to understand the principal mechanisms affecting the production, and propose methods by which we can extend the phenomenon to other fields with similar characteristics.

In our experimental investigation section, we continue to describe the use of surfactant to alter the wettability of the rock. By altering the wettability, we may be able to recover additional oil through imbibition and gravity drainage process.

In our Engineering and Geological Analysis section, we present a new technique for generate alternate permeability distributions at unsampled wells.

Table of Contents

Disclaimer	ii
Abstract	iii
Table of Contents	iv
Executive Summary	1
Experimental	2
Results and Discussion	7
Engineering and Geological Analysis.....	7
Technology Transfer	9
Conclusions	10

Executive Summary

The analysis of available data continued during this quarter. Based on our analysis, we realize that it is possible to improve hydrocarbon recovery by altering the wettability of rock. We also developed a procedure for generating alternate permeability distributions using the underlying uncertainties of rock types. The procedure is demonstrated using some sample wells.

Experimental

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Introduction

The objective of the third phase of this project is to test the feasibility of improved recovery in the Hunton reservoir. Because the reservoir is fractured and parts of the matrix may be oil-wet, a large amount of oil may be trapped in the matrix. Surfactant solutions can be introduced into the fractures which can diffuse into the matrix and change the wettability to moderately water-wet. Then surfactant water can displace the oil by gravity drainage. We have conducted this surfactant-aided gravity drainage process in low permeability limestone cores with a permeability typical of the Hunton reservoir. The effect of matrix permeability and core size (or fracture spacing) is studied at the laboratory scale.

Material

A limestone, Texas Cordova Cream obtained from a quarry near Austin was used in the imbibition experiments. Porosity was about 22.5%. The air permeability of the cores was about 7 md, similar to the Hunton cores. Some other limestone cores of permeability of about 150 md air permeability were used for comparison. The cores were typically 1.5 inch in diameter and 6 inch long. Some of the cores were cut across the diameter or along the length to test the effect of matrix dimension or fracture spacing. The oil was from a West Texas fractured carbonate field. It was 28.2 °API. The dead oil viscosity was 19.1 cp. The acid number and base number were 0.2 and 1.17, respectively. A synthetic brine composed of Na_2CO_3 was used for the anionic surfactants to lower adsorption and surfactant requirement. Imbibition studies are conducted with the surfactants A38 (supplied by Sasol). Our previous studies had indicated that A38 is a good wettability altering agent and lowers the IFT considerably (~ 0.01 dyne/cm). Surfactants are used as supplied, without further purification.

Imbibition Study

Each core was first completely saturated with a 0.1M NaCl brine. 5 PV of crude oil was injected to drive the core to connate water saturation. Oil saturation at the end of this oil flood was 72%.

The core was immersed in the crude oil and aged for 18 days at 80 °C. This procedure makes the core oil wet. Very little oil imbibes into the core if surrounded by NaCl brine or water. For each core, an imbibition cell was filled with the surfactant (0.05 wt%)-Na₂CO₃ (0.3M) solution. The aged core was placed in the imbibition cell. As the oil was produced, it floated up the imbibition cell and collected at the top. Some of the oil remained stuck to the top surface of the core; the cells were not shaken intentionally to release these drops from the top of the core. Part of the oil also dissolved in the surfactant solution. Some of the oil drops remained in the water phase forming a slowly separating emulsion. The volume of the oil collected at the top of the imbibition cell was monitored, but not the amount of oil in the emulsion or at the surface of the core.

Results

Figure 1 shows oil recovery for four cores, with the same surfactant solution. Three of the cores are 7 mD; the fourth one is 150 md. The first low permeability core is 14.8 cm long. The second core is 7.4 cm long, but cleaved vertically along the length. The third core is 7.4 cm long, but cut horizontally. The fourth core is 14.8 cm long. Diameter of all the cores is 3.7 cm. The imbibition cells of the first three (low permeability) cores at 50 days are shown in Figure 2. In about 50 days, the recovery is about 10% for the first core. This is the left most core in Figure 2. The oil collected at the top is counted in this recovery. In this case, the water is almost opaque because of long standing oil emulsion. Another 5-10% oil may be present in this emulsion, but are not counted here in oil recovery. The recovery is the highest, about 51%, for the second core, which was vertically cleaved. This is the right most core in Figure 2. The water does not have much emulsion in this case and relatively clear. The recovery was also high, about 48%, for the third core (the middle core in Figure 2), which was cleaved horizontally. The high permeability core, the fourth core, also had high (about 43%) recovery in about 50 days. These experiments show that oil recovery can be high, of the order of 50% OOIP in about 50 days, with a very dilute (0.05 wt%) surfactant solution even in low permeability fractured media.

Figure 1: Effect of diffusion length and fracture length on oil recovery.

Figure 1 shows that decreasing the matrix size increases the rate of oil recovery considerably. Cores 1 through 3 were the same except for the matrix size. Earlier experiments (Seethepalli, *et al.*, 2004) suggested that the process of oil recovery from fractured carbonate media by surfactant solution imbibition is mostly gravity-driven. Hagoort (1980) expressed oil recovery in terms of a dimensionless variable, t_{Dg} , given by

$$t_{Dg} = (k k_{ro}^0 \Delta\rho) / [(S_{oi}-S_{or}) \phi \mu_o L]. \quad (1)$$

This would mean that rate of recovery from low permeability (k) cores would be slow. From the simulation of imbibition experiments (Adibhatla, *et al.*, 2005), it was also seen that surfactant diffusion is also critical for rate of recovery. One way to improve the recovery rate is by decreasing the diffusion length scale. The experimental results shown in Figure 1 support the theory that recovery rate decreases with smaller fracture spacing.

Figure 1 also shows that the oil recovery rate decreases with core permeability. Comparison between core 1 and 4 shows that as the matrix permeability decreases, oil recovery rate decreases. One expects this behavior from Equation 1. Thus, for fast recovery, it is preferable to have higher permeability and smaller fracture spacing.

Figure 2: 7md cores in the imbibition cells. Core 1 is in the left; core 2 is in the right; core 3 is in the middle.

Figure 3 shows the imbibition results for two different oils in two different cores. All the cores were aged with a field oil to attain oil wettability. In two of the cores, the crude oil was replaced by decane. We wanted to see the effect of oil viscosity by replacing the crude oil with decane. Many other things also changed by the replacement. The surfactant system with decane may not be at its optimal salinity, and the IFT with decane is higher than that with the crude oil. Another aspect of replacing the crude oil by decane is that some of the asphaltenic compounds in the oil can drop out during the decane flood. Irrespective of these two issues, Figure 3 indicates an increased rate of recovery for both low and high permeability rocks. Decane recovery was about 58% OOIP compared to 43% for crude oil in 50 days in the higher permeability rock. The recoveries were 12% (decane) and 10% (crude oil) for the low permeability rock. The process is gravity-driven, hence the rate of recovery increases with a decrease in the oil viscosity, according to Equation 1. A gel formation was observed in between the oil phase and the water phase with decane. It is not clear whether this gel forms only outside the core or even inside the core; it needs further investigation. We saw no gel formation with the crude oil systems.

Figure 3: Effect of oil on the oil recovery at two permeabilities

Results and Discussion

Engineering and Geological Analysis

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In the last report, we developed a scheme for describing the rock types. Using the geological input, as well as porosity data, we developed a scheme to generate rock type description such that each rock type has a unique geological characteristic, as well as unique petro-physical behavior. The petro-physical behavior includes different porosity distributions, as well as different permeability-porosity correlation. Using the available porosity data at the well locations, we could generate alternate rock type descriptions at each well.

The next task in the description is to develop a procedure such that log data and simulated rock type data can be used to generate alternate permeability description. Knowing the porosity and rock type at a given depth, we can sample appropriate permeability value knowing the relationship between permeability and porosity value for a given rock type. Figure 4 shows examples of generated permeability distributions at three sample wells in the field. From the alternate permeability realizations it can be seen that the overall trend is preserved but local variations within the permeability distribution indicate the uncertainties associated with permeability distributions.

Figure 4: Alternate Permeability Distributions at three wells

Technology Transfer

No technology transfer activity was conducted during this quarter.

Conclusions

Based on the material presented in this report, the following conclusions may be drawn:

- Use of surfactants can help us to change the wettability of the rock. If we can change the wettability of the rock from moderately oil wet to water wet, additional oil can be recovered using imbibition process
- A method is developed to generate alternate permeability distributions at unsampled wells and is demonstrated using example wells.