# FORMATION DAMAGE TESTS OF SOME COMPLETION FLUIDS

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*Completion and workover fluids are invading into the producing zone causing formation damage. This damage may be induced due to precipitation of some solid particles suspended in workover fluids or incompatibility of workover fluids with producing formation, formation water and crude oil. Therefore, brines are commonly used as workover fluids. In the present work, a laboratory study was carried out to investigate the effect of employing some workover fluids on formation permeability. Workover fluids used were 8.5 ppg low density calcium chloride brine, 14.5 ppg high density calcium chloride/calcium bromide brine, low density brine with 0.3 % surfactant and high density brine with 0.3 % surfactant (Petronate). Results showed that damage may be reduced when low density calcium chloride fluids are used. Also, the addition of surfactant (Petronate) to the workover fluids can improve formation permeability and reducing formation damage.*

## INTRODUCTION

Oil wells are susceptible to formation damage caused by the contact of completion fluids, workover fluids or stimulation fluids with producing formation [1]. This damage is caused by the precipitation of suspended solids in treating fluids and plugging the pore channels [2]. This damage can be reduced by filtering the treating fluids through a 2-micron filter at the surface [3]. Also, clay particles which exist in sandstone producing formation will swell and cause formation damage [4]. X-ray diffraction test should be done to determine the type and amount of the clay in the sandstone cores to choose the suitable treating fluid [2]. Also, clays are capable of migration when contacted by a foreign water [5]. The formation damage due to employing brines with different densities was determined. Unfavourable fluid/ rock interactions was observed when calcium brines with densities higher than 14 Lb/gal were used [5]. Formation damage by high density brines increases at high temperature [6]. Recently surfactants are commonly used in well completion or workover operations to reduce formation damage and preventing water blocks and emulsions [7,8]. The main aim of this study is to investigate the effect of employing different workover brines on the permeability of some sand-stone core samples. This can be accomplished by measuring the permeability of the core sample and determining the mineral compositions of the core using x-rays.

A special set-up was constructed to measure the permeability of the core sample after injecting low density and high density brines with surfactant (Petronate) and without surfactant.

## EXPERIMENTAL SET-UP FOR FORMATION DAMAGE STUDY

Permeability tests were carried out using Hock cell as shown in Fig. 1. The cores used in this study were sandstone cores having 3.8 cm diameter and 7 cm length. All cores were dried at 200 ºC to remove water from the internal pore spaces. The core was then mounted in the Hock cell, confining pressure of 68 atm was applied to the core, the core was evacuated and then saturated with 10 % NaCl solution as reference brine from left to right. Then the sample was fully saturated with crude oil, when the permeability was stable for at least four hours, this value was taken as initial permeability.

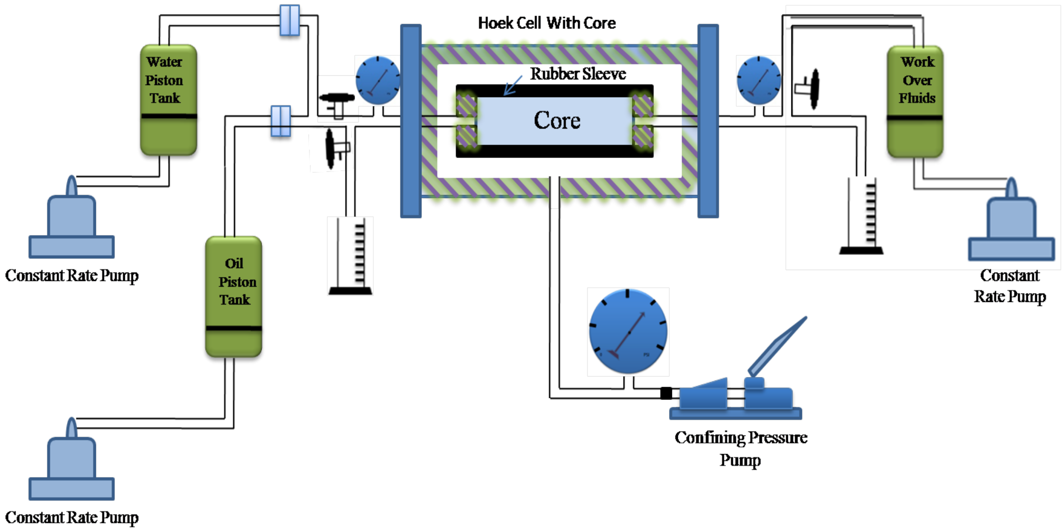


Figure 1. Experimental set-up used in formation damage study

Different fluids such as low density calcium chloride, and high density calcium chloride / calcium bromide of 10 pore volume were injected from right to left side of the core. Pressure drop and flow rate were recorded and final permeability to oil was established. Permeability ratio (the ratio between permeability after damage and permeability before damage) was calculated. Also, the effect of adding surfactant to calcium chloride and calcium chloride / calcium bromide brines on permeability ratio was studied.

## RESULTS AND DISCUSSION

The x-ray analysis of a sandstone core sample using x-ray differactometer is shown in Fig. 2. It shows that the main component of the sample is quartz with some traces of clay.

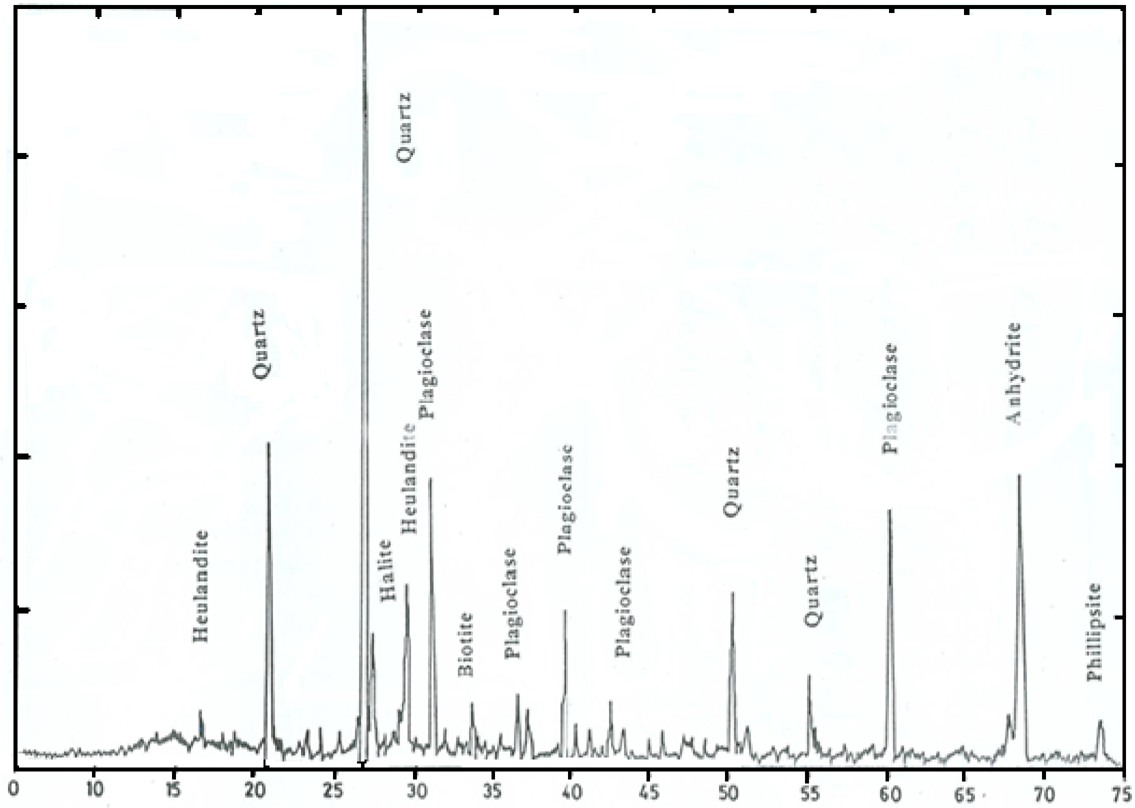


Figure 2. X-Ray differactogram of the tested sample

The permeability ratio for the core samples due to injecting different brine fluids are tabulated in table 1 and presented in Fig. 3.

Table 1

Permeability ratio due to using different workover fluids

| ***Workover Fluids*** | $K_o/K_{oi}$ |
|---|---|
| Low Density Fluid (3 % Ca $Cl_2$) | 0.85 |
| 14.5 high Density Fluid (Ca $Cl_2$/$CaBr_2$) | 0.39 |
| Low Density Fluid with 0.3 % Surfactant | 0.86 |
| 14.5 high Density Fluid ($CaCl_2$/$CaBr_2$) with 0.3 % Surfactant | 0.59 |

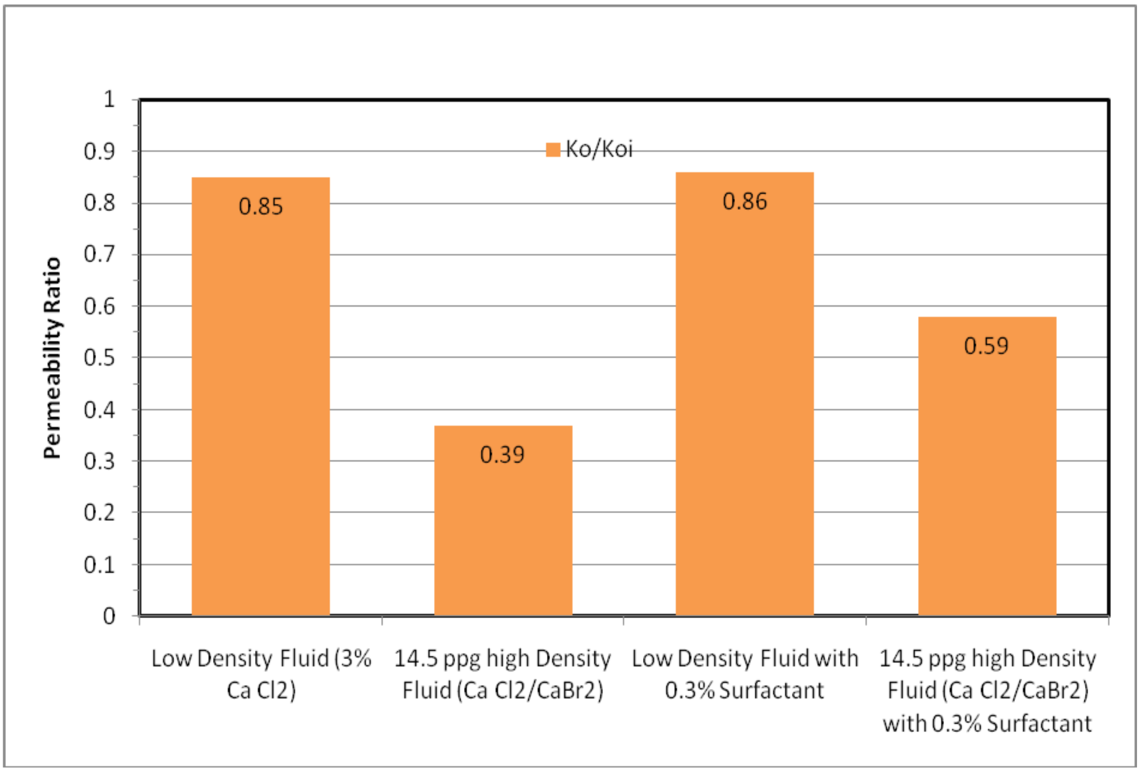


Figure 3. Permeability Ratio for Core Samples Using Different Workover Fluids

Figure 3 shows that the least damage was occurred by injecting workover brines with 0.3 % surfactant. Using small amount of surfactant 0.3 % by volume with low density brines can improve the formation productivity. Surfactant is reducing the interfacial tension, retarding the growth of insoluble particles of calcium salts and preventing oil wetting the rock samples. Less improvement in productivity ratio was obtained when using high density brines of $CaCl_2$/$CaBr_2$ with 0.3 % surfactant.

The damage caused by employing low density brine of 3 % calcium chloride solution was low because when calcium chloride brought into contact with clay particles, some sodium ions were replaced by calcium ions resulting in clay particle shrinkage and hence less reduction in permeability. The damage resulted from high density brines of 3 % $CaCl_2$ solution and 97 % $CaBr_2$ is high due to insoluble salts formed during contact of calcium ions on rock matrix and low mobility of heavy brines [9]. To prevent the precipitation of insoluble brine salts the PH of $CaCl_2$ and /or $CaBr_2$ brines is lowered by adding a minimum of 8 % $ZnBr_2$ [10].

## CONCLUSIONS

Based on the results of the experimental work, the following conclusions are obtained:

1. Low damage was caused by low density 3 % $CaCl_2$ workover fluid due to swelling inhibition caused be ion exchanges of clay particles.
2. High damage was resulted by employing high density $CaCl_2/CaBr_2$ workover fluids due to the existence of high percentage of solids.
3. Permeability ratio was improved by the addition of surfactant (Petronate) to low density or high density workover fluids.

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