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Quantifying Softening of Reservoir Rock by Fracturing Fluid

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Summary

A quantitative method of measuring combined fluid imbibition and leakoff into unconventional reservoir rock has been developed. The chemo-mechanical impact of a fracturing fluid can be measured on core samples at reservoir conditions in a controlled lab environment.

Introduction

Hydraulically fracturing unconventional reservoirs requires large quantities of fluids that often damage the rock. Treatment fluid can negatively affect relative permeability to hydrocarbons in the rock. It disrupts the chemical equilibrium of the rock/fluid system, leading to a physically and chemically altered zone of rock adjacent to the fracture face. Loss of rock strength due to fluid invasion can lead to increased proppant embedment, a reduction in fracture conductivity, and fines generation. For optimal production it is important to understand the rate of combined fluid leakoff and imbibition, the amount of fluid invading the rock matrix, the depth of the altered zone, and the loss of rock strength in this zone.

Theory and/or Method

A laboratory method to quantitatively measuring combined fluid leakoff and imbibition into ultralow-permeability rocks such as shales under reservoir conditions was developed. Dissecting the plug with a mechanical scratch testing machine and precise determination of the water content as a function of plug depth results in water saturation and rock strength profiles throughout the plug. This enables correlating the loss of rock strength with induced water saturation and, thus, quantifying the damage associated with fracturing fluids.

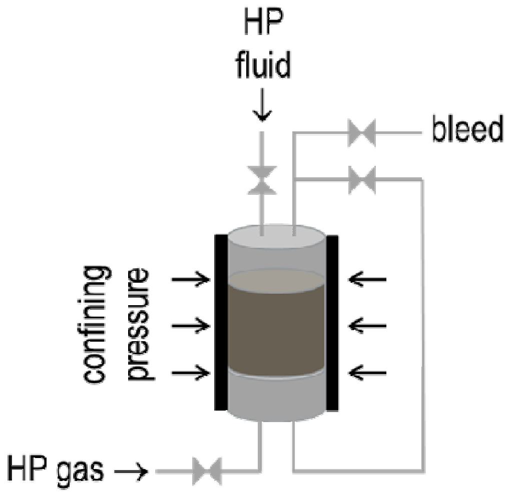

Figure 1, *Scheme of measurement setup*

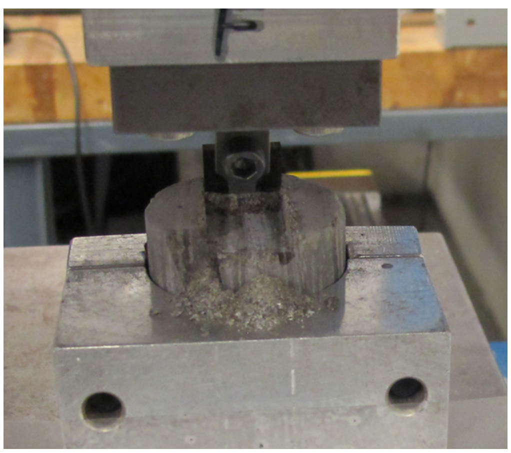

Figure 2, *Sample plug on a mechanical scratch tester*

Examples

Experiments performed on core plugs from several major shale plays show that fluid loss into ultralow permeability rock can be substantial. However, the fluid loss is also highly variable and dependent on the texture and composition of the rock. The rock strength decreases with increasing exposure time to the fracturing fluid and correlates with the invading water saturation. This suggests that fluid leakoff, imbibition, rock weakening and fracture conductivity are strongly linked. Therefore, knowing the variation of leakoff and imbibition into the different rock types encountered by the fluid enables predicting where the treatment fluid goes, how it is distributed in the rock matrix behind the fracture face, and how best to mitigate the effects by choosing the fluid and procedure that causes the least damage to the rock and, ultimately, fracture conductivity.

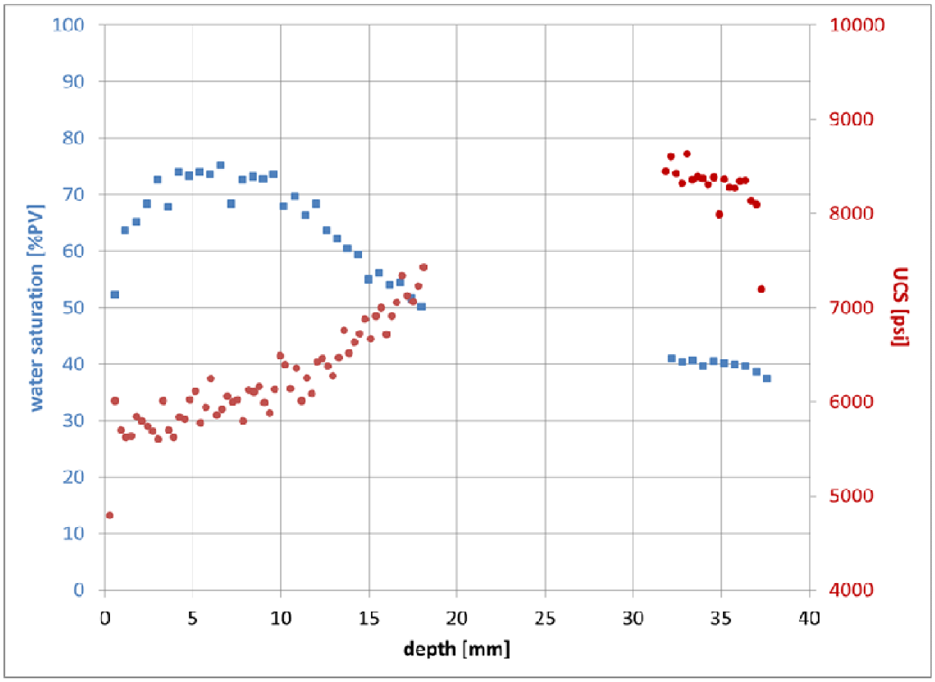

Figure 3, *Example of water saturation and unconfined compressive strength (UCS) profile in a sample plug*

Conclusions

The newly developed method to measure leakoff and imbibition behavior and the chemomechanical impact of fluid invasion into unconventional reservoir rock was successfully applied to many samples of several major shale plays. The measurements can potentially explain where the residual treatment water goes in a formation and how it affects well production. This measurement method can also be used to determine the impact of the treatment water on the mechanical properties of the near-wellbore and fracture region of the rock by providing the depth of the invaded zone and the extent of chemo-mechanical damage. The formation and severity of water blocks can be estimated by the maximum water saturation measured behind the fluid/rock matrix interface. Combined with a rock classification system, valuable information on formation damage as well as location and impact of residual treatment water can be gained. Fluid/rock interaction is inevitable but with the right tools, it can be planned for and minimized.