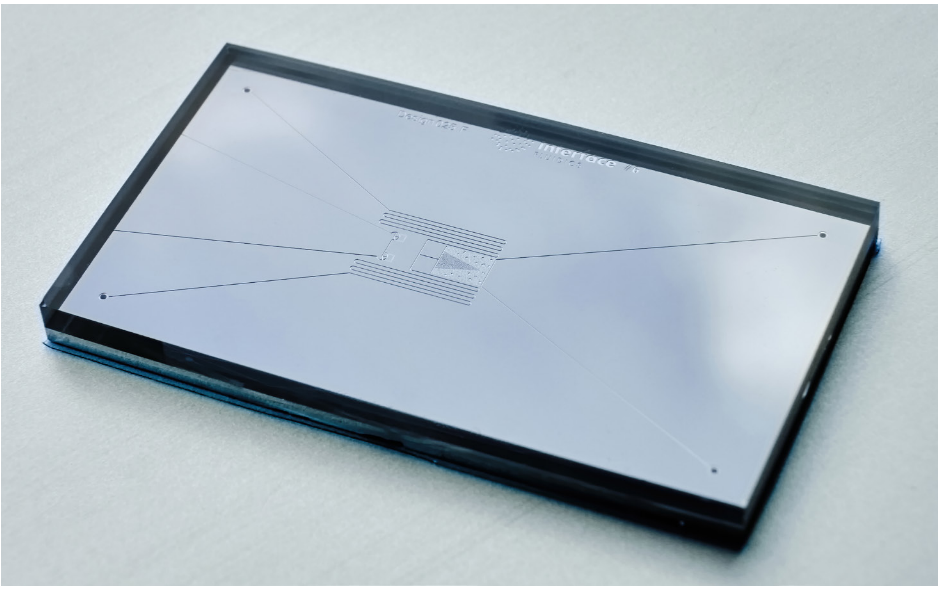
Rapid Evaluation
of Stimulation Fluid Performance on Reservoir Analogues

A study of fluid evaluation in the Eagle Ford

Abstract:

Microfluidics - when adapted for oil and gas - is a technology that helps the energy industry evaluate an array of stimulation products and their compatibility with individual reservoirs for specific applications down-hole. This paper outlines the benefits of microfluidics analysis, how a large multinational operator applied it, and how it impacted decisions being made in the field.

Traditional lab testing employed for evaluating stimulation fluids can take months in a tight shale core and poses limitations to repeatability and the understanding of why a fluid behaves a certain way. The technology evaluated in this testing allows for a rapid, visual understanding of the fluid-fluid interaction under reservoir representative conditions, allowing for quick data-driven decision making.



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Background

A United States-based operator was seeking specific surfactant products applicable to their Eagle Ford reservoir conditions and were given several choices by service companies and chemical vendors. The data presented from the respective companies was typically done at ambient conditions or no greater than 200°F (95°C) which did not accurately represent their reservoir temperature of 325°F (160°C). This laboratory data supplied usually comprised of surface tension, contact angle, interfacial tension, and spontaneous imbibition result. Since none of the companies had product stability data nor the ability to test at reservoir temperature, a decision was made to utilize Interface's microfluidic technology to get the required data. This data comprised of reservoir rock properties, including permeability and porosity values, wettability parameters, water composition and oil from the respective well test area. The data set would provide a necessary first pass to evaluate if any of the products had the potential to improve recovery at reservoir temperature and pressure, mitigate the risk of reservoir damage, and determine if the cost of implementation is acceptable.

Technology

Interface Fluidics is a technology-enabled oilfield laboratory services company that provides fluid analysis testing on custom fabricated reservoir analogues. Their testing and technology were used in conjunction with a US-based operator's reservoir parameters and oil to evaluate a range of stimulation fluids.

Interface's Flowback Test involves using a reservoir analogue, in place of core, in an experiment similar to core flooding. The reservoir analogue has a porous pattern that replicates the inherent geometries of the reservoir rock using available geological information provided by the operator. Prior to testing, the analogue is saturated with formation brine and oil, and the system's wettability is modified to reflect that of the reservoir. Testing is conducted at specified reservoir representative conditions including temperature and pressure.

Image 1: Fluorescence microsocpy

A major benefit to Interface's technology is the ability to optically observe what is happening at the pore scale level through fluorescence microscopy and the use of applied machine vision software. The results of this testing provided the operator with the ability to see if a product caused damage to the reservoir, created preferential pathways, deposited solids, or created emulsions. Interface's Flowback Test enables the quantification of results to understand why and how fluids are performing, helping to reduce the risk of damaging the reservoir by providing the data needed to make strategic decisions on downhole completions.

The testing also allowed for repeatability as the system, including the porous media, is highly controlled, a capability unique to this technology. The only variation in the testing protocol was the stimulation fluid being used. The system requires less than 10 mL of oil and product to run 1 test, allowing for ease of shipment and sampling from the field to the laboratory.

Testing

The testing was designed for an Eagle Ford reservoir, highlighting an area with challenging conditions. The reservoir had a low permeability with small pore-throats, high reservoir temperature of 300 ºF, and the chosen wettability was intermediate- to oil-wet.

- Reservoir analogues were designed and fabricated at a pore throat size of sub-100 nm and a permeability of approximately 1.5 μD.
- The salinity of the connate water was approximately 42,000 TDS with the base frac water having a salinity close to 1,200 TDS.
- The oil was provided by the operator from a representative well in the Eagle Ford.
- The wettability was modified to an intermediate-wet for the primary set of testing, then with all the same parameters, wettability was modified to an oil-wet for the secondary set of testing.

Six products - labeled A through F - were used for testing. The product names, compositions, or chemical vendors from which they came, were unknown to Interface. Each product was tested at both 1 and 2 L/m^3, and a pure base frac water was run as a control. In total 26 tests, plus 5 repeats were performed over 61 days with results being analyzed and presented 2 weeks after the testing was completed.

Analogue Design

The reservoir analogues are two dimensional and replicate a thin section of the reservoir. The use of two-dimensional models offers several advantages including the ability to visualize pore-scale fluid flow and increase the speed of testing and repeatability. To ensure a representative porous medium, care was taken to precisely design a system that replicates the pore-scale fluid behavior of the operator's Eagle Ford reservoir. It is at the pore-scale where fluid-fluid interactions have the greatest impact on oil recovery, maximizing the stimulated rock volume.

The analogue replicates where the high-permeability fracture meets the low-permeability matrix (see Figure 1). At this scale, the analogue design ensures the magnitude of the dominant forces are captured, caused by fluid-fluid interfacial tension and the resulting capillary pressures. Capillary pressure is dictated by the nano-scale depth of the nano-network and system wettability.

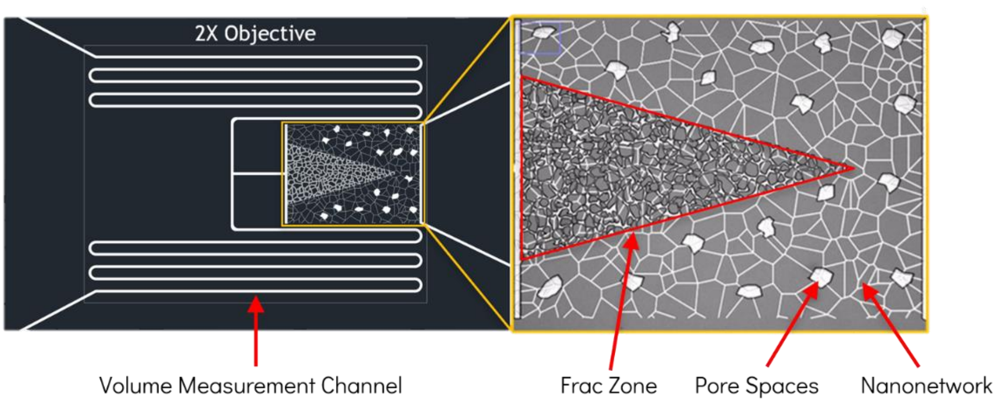

Figure 1. Schematic of the microfluidic analogue used for screening the products. Left is the CAD design of the model. Right is the actual fabricated analogue under the bright-field microscopy. The volume measurement channel is designed to accumulate the produced oil and measure its volume optically as a function of runtime.

Analogue Preparation

The analogue was first prepared to match the chosen starting wettability of the reservoir rock for both intermediate-wet and oil- wet. This is done through various aging and coating processes. With the defined wettability angle matching either water-wet <75°°, intermediate-wet 75-105°° or oil-wet >105°°.

Testing Process

The analogue was filled with formation brine and oil from the operator's specific reservoir, and the test temperature was set to match the reservoir temperature. Testing began by increasing the pressure on both sides of the analogue and slowly injecting stimulation fluid at a constant pressure drop, from the high-permeability area into the low-permeability matrix for a period of two hours (left to right in all images).

Once the stimulation fluid was injected, it was left to soak for a shut-in period of two hours. After the soak period, oil was then flowed back across the system from the low-permeability matrix to the high-permeability fracture zone at a constant pressure drop.

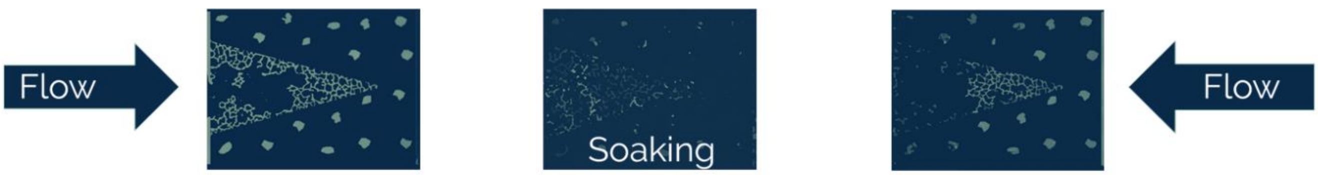

Figure 2. Three stages of testing include a) stimulation fluid injection; b) soaking period; c) oil flowback.

Evaluation Metrics

All performance measurements, listed below, were made optically, using fluorescence microscopy, along with the sensor data to back it up where possible. As oil naturally fluoresces across the visible spectrum, Interface's proprietary machine vision software analyzed the fluorescing pixels to calculate each of the four metrics used for evaluation of products in the Interface Flowback Test.

The primary performance measurement is the volume of oil flowback over a period of two hours of constant pressure differential. This is calculated using the machine vision software to optically measure the volume, in nanoliters, that accumulated in the volume measurement channel.

There are three secondary measurements used to explain why and how a product performed. The first is displacement efficiency, analogous to a core flow test, where Interface evaluated how much oil was displaced by the injection of the stimulation fluid. Interface then quantified the percentage of oil displaced by each stimulation fluid A through F.

Regain saturation is the second measurement used to evaluate the stimulation fluids. After the product was injected, oil flowed back and Interface quantified the percentage of oil in the system, evaluating how well the pore spaces and fracture were refilled with oil.

Finally, wettability was calculated at the mean ± standard deviation of 30 oil/water contact angle interfaces measured in the high-permeability zone of the analogue in two conditions: (i) initially, before testing is started and, (ii) after oil flowback. Contact angles evaluated the three-phase intersection angle of the flowback aid solution, oil, and the analogue surface.

Results

In the 1 L/m^3 intermediate-wet testing, two products were identified as being top performers since they flowed back significantly more oil than the other products and were the only two stimulation fluids that outperformed the control run. An interesting finding was that when the concentration was increased to 2 L/m^3, one of the top performers from the 1L/m^3 test run, did not perform well and caused damage to the pores and channels of the analogue.

The resulting contact angle measurements show that in each of the cases the stimulation fluids were able to reduce the contact angle consistently to around 50-55°, altering the wettability to a more water-wet system, even at the high temperatures. However, four of the six products tested in the intermediate-wet analogue, for both 1 and 2 L/m^3 concentrations, resulted in significant damage by forming solids and plugging the pore-throats, with some products not allowing any oil to flowback. In the oil-wet testing at 1 L/m^3, all the products outperformed the control. However, one product did flow back significantly more oil.

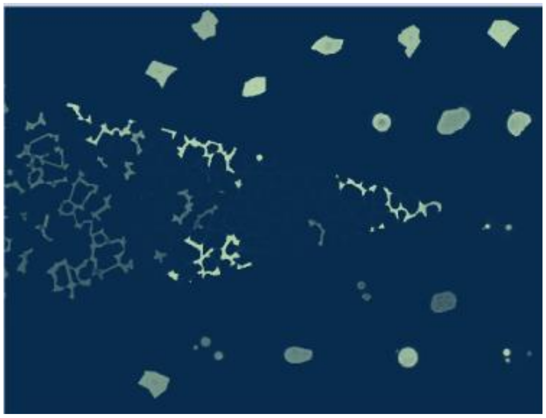

Figure 3: One product after flowback showing damage and preventing oil from flowing through the pores and fracture

When the concentration was increased to 2 L/m^3, the same product was the top performer, while the other products still outperformed the control. This was observed by measuring the volume of oil flowed back, as well as evaluating the displacement efficiency. It is interesting to note that in the 1 L/m^3 case, the product that performed well compared similarly in displacing the oil from the frac zone as the other products, however, in the matrix it was able to penetrate into the pore throats and had a 40% improvement over the other products. The following regain oil saturation showed a similar result, where that top performing product allowed the oil to saturate 57% of the matrix upon flowback, compared to 22% for the next best product.

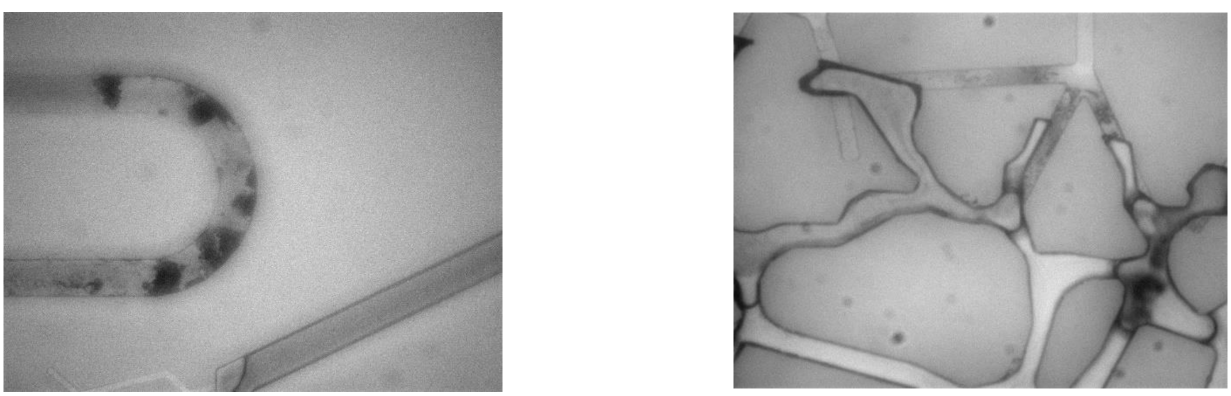

Figure 4: Clogged pores and channels at 300°F

Conclusion

Interface’s flowback testing allows for rapid screening of downhole stimulation fluids. While there is a number of testing methods in the market to evaluate the formation interaction with stimulation fluids, none are truly representative of downhole conditions. When compared to core or other industry standard testing, Interface’s advantage is the ability to visualize the fluid-fluid interaction, under relevant reservoir conditions. Through the high-resolution optical access of the flowback process, Interface has unique ability to differentiate product performance based on the amount of oil flowed back and evaluate any damage that might be occurring. What has been found is that fluids perform differently under different operating conditions. Parameters such as temperature, oil characteristics, salinity of the connate/injected water, and concentration can impact how and why a fluid performs.

By employing Interface’s testing, the operator was able to rapidly screen the flowback performance of six stimulation additives at two different concentrations and under reservoir conditions. More broadly, Interface’s flowback testing platform can provide comprehensive decision-making information, enabling the operators to optimize the fluids, reduce the costs, and ultimately de-risk the operations.