

Acid Stimulation of High-Temperature Sandstones in Eastern Venezuela

Wells in this eastern Venezuela oil field have a bottomhole temperature of approximately 230°F and varied mineralogical composition from interval to interval. Near-wellbore fines damage and carbonate-scale damage have been reported. A novel chemical system was developed to stimulate these high-temperature sandstone reservoirs.

Introduction

Most of the wells in this field in Maracaibo, Venezuela, have several perforated intervals covering up to 1,000 ft, with a net perforated interval of up to 500 ft. The mineralogy varies from interval to interval, with 4 to 16% calcium carbonate (CaCO₃), 6 to 18% clays (mainly kaolinite), 5 to 10% feldspars, and 2 to 5% siderites in some wells. Reservoir pressures range from 800 to 2,500 psi, and skin values vary across the zones. Permeability varies from 1 to 200 md among the zones. The main formation-damage mechanisms were identified as fines migration (80 to 90% production decline after treatment) and CaCO₃ scales, mainly from loss of workover fluids. Various formulations of mud acid, organic-clay acid, and solvents are used to treat these wells, with mixed results.

This article, written by Technology Editor Dennis Denney, contains highlights of paper SPE 98318, "Effective Stimulation of High-Temperature Sandstone Formations in East Venezuela With a New Sandstone-Acidizing System," by S.A. Ali, SPE, and C.W. Pardo, SPE, Chevron Energy Technology Co., and Z. Xiao, SPE, F.E. Tuedor, SPE, A. Boucher, SPE, S.A. Al-Harthy, B. Lecerf, and G. Salamat, SPE, Schlumberger, prepared for the 2006 SPE International Symposium and Exhibition on Formation Damage Control, Lafayette, Louisiana, 15–17 February.

The new sandstone-acidizing system was developed to treat multilayered high-temperature (200 to 375°F) reservoirs with long production intervals and complex mineralogy. The new sandstone-acidizing fluid uses a single-stage placement process, has less precipitation tendency and reduced tubular and production-equipment corrosion, and reduces exposure of hazardous fluids to wellsite personnel and the environment. A comprehensive laboratory study, which included acid-solubility tests, X-ray diffraction (XRD) analysis, batch reaction kinetics, fines-migration tests, and core-flow tests, was conducted on field cores to evaluate the performance of this sandstone-acidizing system and compare it with currently used systems.

Experiment

Twelve core plugs were used from the formation sand in the oil field. Six plugs were from the 7,951- to 7,953-ft interval, five from the 7,723- to 7,727-ft interval, and one from the 7,757- to 7,758-ft interval. All samples were 1 in. in diameter and approximately 2 to 3 in. long. These core samples were classified into groups of high- and low-permeability sands, although a slight difference in physical appearance was observed in the laboratory.

Acid solubility tests were run on 10 samples. Mineralogical information is very important in sandstone-acidizing treatments. XRD was used to quantify the mineralogical composition of the core samples. Typical minerals in sandstone rock include silica (quartz), feldspars (plagioclase, K-feldspar), clays (kaolinite, illite, chlorite, smectite), and mixed-layered illite and smectite, zeolites, micas, carbonates (dolomite, calcite), sulfides, and sulfates (gypsum, anhydrite, and barite).

Core Flow Tests. Each core was damaged by use of a modified Baroid cell and then treated with different acid systems using the core-flow equipment. The effectiveness of the treatment was evaluated by measuring the regained permeability. Artificial damage and fluid treatment were in the injection direction, and permeability measurement was in the production direction.

The treatments used were as follows.

- New sandstone-acidizing system: 30 pore volumes.
- Mud acid: 10 pore volumes of 10% HCl preflush + 10 pore volumes of 13.5:1.5 mud acid + 10 pore volumes of 5% NH₄Cl.
- Organic-clay acid: 10 pore volumes of 10% HCl preflush + 10 pore volumes organic-clay acid + 10 pore volumes of 5% NH₄Cl.

Geochemical Simulations. The geochemical simulator was calibrated with results obtained from batch reaction and core flow tests. Radial-geometry simulations were run for skin-reduction sensitivity analysis with the following parameters.

- High and low permeabilities.
- Three fluid systems: mud acid, organic-clay acid, and new sandstone-acidizing system.
- Temperature of 230°F.
- Pump rates of 0.01 and 0.02 (bbl/min)/ft of interval.
- Main-treatment pump volumes of 50 and 100 gal/ft of interval.
- The well configurations included treating a 50-ft-thick interval through perforated 5½-in. casing.

Results

Acid-Solubility Tests. Assuming that Ca, Fe, and Mg were from the carbonate minerals, the semiquantitative carbonate and acid-soluble-clay content were calculated. The intervals had a

For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt. The paper has not been peer reviewed.

total acid solubility of 2 to 12% and averaged 8 to 10%. The average carbonate content was 3 to 4%, and acid-soluble-clay content was 6 to 7%. The highest clay content (9%) and lowest carbonate content (2%) were in the sample from 7,758.1 ft. The variation in carbonate and clay content in the 7,951- to 7,953-ft interval was greater than in the other intervals.

XRD Analysis. Low-permeability intervals had a higher content of carbonate (approximately 4%) and clays (approximately 7%) than high-permeability intervals (2% carbonate and 5% clays). Carbonate minerals were mainly siderite and ankerite. Sensitive clays such as chlorite, smectite, or mixed-layered illite/smectite were present in the high-permeability samples. This information was consistent with the results obtained from acid-solubility tests.

Reaction Tests. The new sandstone-acidizing system was able to dissolve carbonates and clays and keep them in solution to minimize the formation of precipitates. Consistent with acid-solubility results, batch-reaction data indicated that iron carbonate content was high in both high- and low-permeability formations. However, less Ca and Mg was found in the high-permeability sample (7,951 to 7,957 ft) than in the low-permeability core (7,723 to 7,725 ft).

Critical-Velocity Determination. It was observed that some fines movement occurred at flow rates between 8 and 16 cm³/m on the low-permeability core. However, no fines movement was noticed, even at a flow rate of 16 cm³/m, for the high-permeability sample. Fines movement in these samples was not significant.

Core Tests. Figs. 1 and 2 show the treatment responses of the new sandstone-acidizing system on damaged core samples. The core (1 in. in diameter and approximately 3 in. long) was damaged by solid slurry, resulting in approximately 0.5-mm-thick filter cake being formed on the core face. For the high-permeability core (Fig. 1), the permeability declined from 3.7 to 2.9 md as a result of the simulated scale and fines damage. The permeability improved to 3.6 md after the new sandstone-acidizing-system treatment. Regardless of the flow direction (both

production and injection directions), the final permeability remained at 3.6 md, indicating the absence of post-treatment fines-migration problems. For the low-permeability core (Fig. 2), the permeability declined from 1.2 to 0.9 md as a result of the simulated scale and fines damage. The permeability improved to 1.6 md after the new sandstone-acidizing-system treatment. Again, regardless of the flow direction, the final permeability remained at a value of 1.6 md, indicating the absence of post-treatment fines-migration problems.

For a mud-acid treatment on a low-permeability core, the permeability declined from 1.6 to 1.4 md after the slurry damage. The flow direction (injection or production) had no effect on the permeability value. A significant permeability reduction (from 1.4 to 0.4 md) was noticed with the HCl preflush, an indication of serious damage caused by HCl preflush, which is not compatible with sensitive clays such as bentonite introduced in the slurry damage. The mud-acid treatment increased the permeability slightly to 0.8 md, still low compared with the initial permeability of 1.6 md and damaged permeability of 1.4 md. The dramatic increase in the permeability during the post-flush with 5% NH₄Cl could be attributed to the fluid flushing the secondary damage out of the relatively short core plug. However, when the flow direction was reversed from injection to production, the permeability dropped to 0.8 md—a strong indication of a fines-migration problem after mud-acid treatment.

Core-Test Summary

The mud-acid treatment did not recover the initial permeability of the core and caused additional damage to the rock. For the high-permeability core treated with organic-clay acid, the permeability declined from 4.2 to 3.9 md after the slurry damage—behavior that was consistent in injection and production modes alike. As was observed with the mud-acid treatment, the HCl preflush of the organic-clay-acid treatment also caused additional damage to the core (i.e., permeability decreased from 3.9 to 2.8 md). The main acid stage and 5% NH₄Cl post-flush returned the permeability to 4.1 md without any indication of fines migration after reversing the flow direction. It is worthwhile to

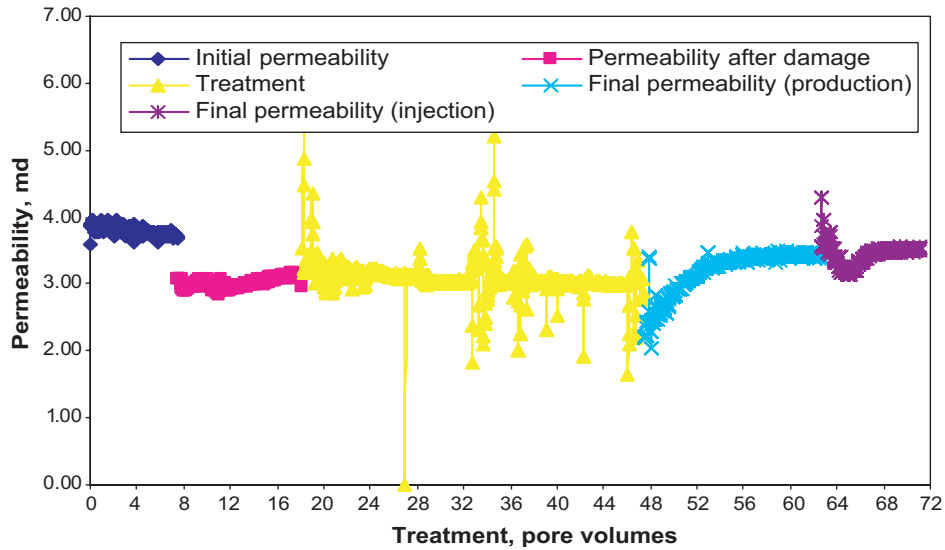


Fig. 1—The new sandstone-acidizing system treatment on a high-permeability core.

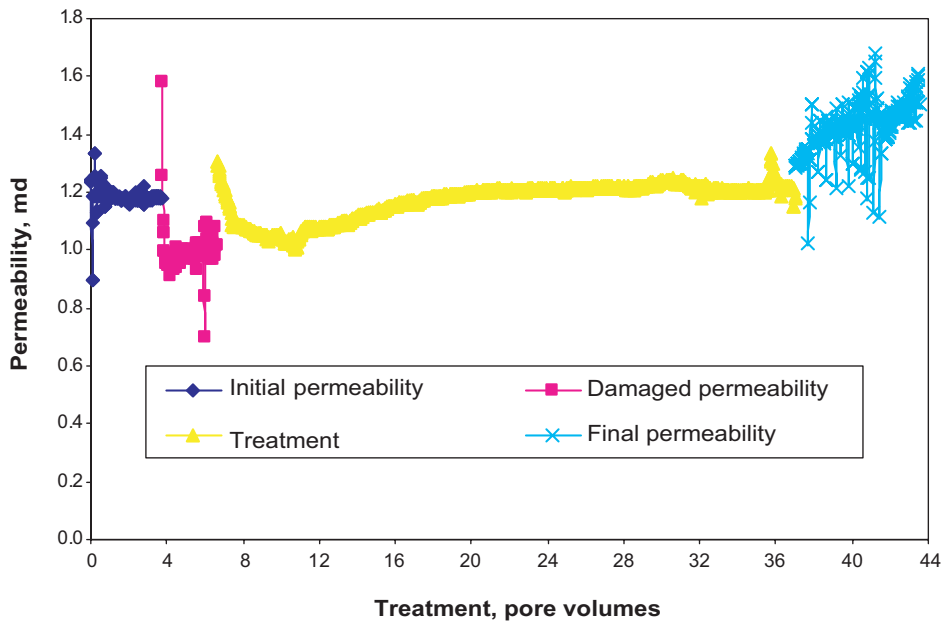


Fig. 2—The new sandstone-acidizing-system treatment on a low-permeability core.

note that in field treatments, the HCl preflush may damage the reservoir rock permanently because the main acid stage and NH_4Cl post-flush may not be placed across the HCl-damaged zone properly—a problem with conventional multistage treatments.

Simulation Results

Generally, the low-permeability formation had a higher potential for stimulation, as with the core tests, which led to larger stimulation (lower final skin) of the low-permeability formation than of the high-permeability zones. The new sandstone-acidizing system

decreased the skin value in all the simulated cases. Its ability to react with both carbonates and clays resulted in a large skin reduction, although it dissolved less clay than mud acid or organic-clay acid.

The core test with mud acid showed large precipitation of silica, as did the simulation. This result is consistent with the large permeability decrease observed during the test. On the reservoir scale, precipitation of amorphous silica was predicted to cause significant damage.

Organic-clay acid decreased skin in the low-permeability formation and, at a high-injection rate, in the high-perme-

ability formation. However, in the case where the injection rate was reduced to 0.01 (bbl/min)/ft of interval in the high-permeability formation, the longer residence time of the acid in the critical matrix generated precipitation of amorphous silica in the near-wellbore region, leading to possible damage. For the organic-clay-acid and mud-acid treatments, it appeared that the HCl preflush dissolved the carbonate effectively in the near-wellbore region. However, it reacted with the acid-sensitive clays to precipitate amorphous silica, which increased the skin in the second part of the HCl stage.

JPT