Oil & Natural Gas Technology

DOE Award No.: DE-FE0024296

Quarterly Research Performance

Progress Report (Period Ending 12/30/2017)

Methods to Enhance Wellbore Cement Integrity with Microbially-Induced Calcite Precipitation (MICP)

Project Period (10/1/2014 to 09/30/2018)

Submitted by:
Adrienne Phillips

____
Signature

Montana State University
DUNS #: 625447982
Energy Research Institute
P.O. Box 172465
Bozeman, MT 59717-2465
Email: adrienne.phillips@biofilm.montana.edu
Phone number: (406) 994-2119

Prepared for:
United States Department of Energy
National Energy Technology Laboratory

January 31, 2017

U.S. DEPARTMENT OF ENERGY | NATIONAL ENERGY TECHNOLOGY LABORATORY

Office of Fossil Energy

ACCOMPLISHMENTS

Goal

The goal of this project is to develop improved methods for sealing compromised wellbore cement in leaking gas wells, thereby reducing the risk of unwanted upward gas migration. To achieve this goal an integrated workplan of laboratory testing, simulation modeling, and field testing is underway. Laboratory testing and simulation modeling (with assistance from the University of Stuttgart) are being conducted at the Center for Biofilm Engineering (CBE) at Montana State University (MSU). Field testing was carried out at the 1498 m (4915 foot) deep Alabama Power Company well (Gorgas #1 well) and at the Rexing #4 well in Indiana owned by Gallagher Drilling. This project is designed to develop technologies for sealing compromised wellbore cement using the process known as microbially induced calcite precipitation (MICP). The project has two main objectives:

Objective 1: Prepare for and conduct an initial MICP field test aimed at characterizing a region of compromised well cement in the Gorgas well which is suitable for MICP sealing. The location chosen for MICP sealing is the interval of 310.0 -310.9 m (1017-1020 feet) below ground surface (bgs). The first MICP sealing test was completed in April 2016.

Objective 2: After thorough analysis of the results from the first field test, our team will conduct a second MICP test using improved MICP injection methods. The second field test will target compromised wellbore cement in an injection well used for water flooding to improve oil recovery in Indiana known as the Rexing #4 well.

After each field demonstration, the following (or equivalent) methods are to be employed to assess effectiveness of the MICP seal: pressure falloff testing, sustained natural gas flow rate testing at the well head, and side wall coring. Successful demonstration of improving wellbore integrity and sealing gas leaks from poor cement bond regions will result in a reduction in the pressure falloff, reduction in the sustained gas flow rate at the well head, noticeable differences in the ultrasonic imaging tool (USIT) or temperature logging data in the targeted biomineralization regions, and demonstration of MICP byproducts ($CaCO_3$) in the treated regions on side wall cores or downhole tubing. In the case of the new well chosen for the second field demonstration, the return to productivity would be an additional measure of success.

The project milestones are shown below in Table 1. This table was updated to reflect the change in milestone dates per the one year no-cost time extension that went into effect October 1, 2015.

Table 1. Project Milestones

Related Task	Milestone Number	Milestone Title	Planned Completion Date	Revised Completion Date	Verification Method
1.0	1	Update Management Plan	11/30/2014	NA	PMP
1.0	2	Kickoff Meeting	11/06/2014	NA	Presentation
2.1	3	Complete construction and testing of wellbore-cement analog testing system. Expected result is a system which facilitates biomineralization sealing in annular spaces representative of field conditions.	3/31/2015	NA	Quarterly Report
3.2	4	Complete first wellbore cement remediation field test. Expected results include obtaining side wall cores and pressure testing to evaluate the extent of biomineralization sealing.	9/30/2015	9/30/2016	Quarterly Report
4.1	5	Complete analysis of field data from first field test. Expected result is a data set which will enhance the design of the second field test.	3/31/2016	3/31/2017	Quarterly Report
4.1	6	Complete design of injection protocol for second field test.	9/30/2016	9/30/2017	Quarterly Report
5.2	7	Complete second field test. Expected results include obtaining side wall cores and pressure testing to evaluate the extent of biomineralization sealing.	3/31/2017	3/31/2018	Quarterly Report
6.0	8	Complete analysis of laboratory, simulation modeling and field data. The expected result will be a comprehensive evaluation of MICP sealing technology for well cement repair.	9/30/2017	9/30/2018	Quarterly Report

Accomplishments under the goals

Project Planning. During this reporting period, teleconference calls were conducted and included Jim Kirksey of Loudon Technical Services for Schlumberger (SLB), Robin Gerlach, Lee Spangler, Al Cunningham, Cat Kirkland, and Adie Phillips (MSU), as well as Randy Hiebert of Montana Emergent Technologies (MET). The subjects of these calls have been: construction and development of the mobile operations center, work to characterize the Rexing #4 well and planning of the second field test. A request for an extension to the milestone report that was due September 30, 2017, was made on October 2, 2017. This request was made because field work was planned for the Rexing #4 well characterization work for the week of September 11, 2017. Unfortunately, Hurricane Irma threatened the weather conditions even as far north as Southern Indiana where the well is located. Given that the well is located in a low-lying area and potential flooding was projected, the field work was delayed. The characterization field work was rescheduled and completed the week of October 9, 2017. Work during this reporting period focused on the preparation for the field demonstration which started the week of November 27, 2017.

April 2016 MICP field test results. As previously reported, the MICP cement channel sealing treatment demonstration was performed in April 2016 over the course of five days where biomineralization fluids and microbial growth media components were delivered downhole using a delivery bailer method. The experiment was successful and three major results were obtained through the demonstration: (1) injectivity was significantly reduced after MICP treatment; (2) a comparison of USIT logs taken before and after MICP treatment of the target interval indicated a significant increase in the solids content after sealing; and (3) pressure fall-off tests after MICP treatment met a definition of mechanical integrity for shut in wells. The positive results have been discussed among MSU, MET, and SLB and the team is in agreement that additional development and demonstration of the technology will advance the technology readiness level of the sealing method.

Thief Zone Laboratory Experiment

Prior to the field demonstration in Indiana, an additional laboratory study was designed to model the field conditions and establish experimental protocols. The lab-scale reactor consisted of (a) two sand columns to model the target injection formation (a low permeability sandstone) and the thief zone (a higher permeability sandstone); (b) a fracture fixture to model the well cement defect; and (c) a pumping reservoir where media solutions were diluted and pumped into the system to model the wellbore injection methods applied in the field (Figure 1).

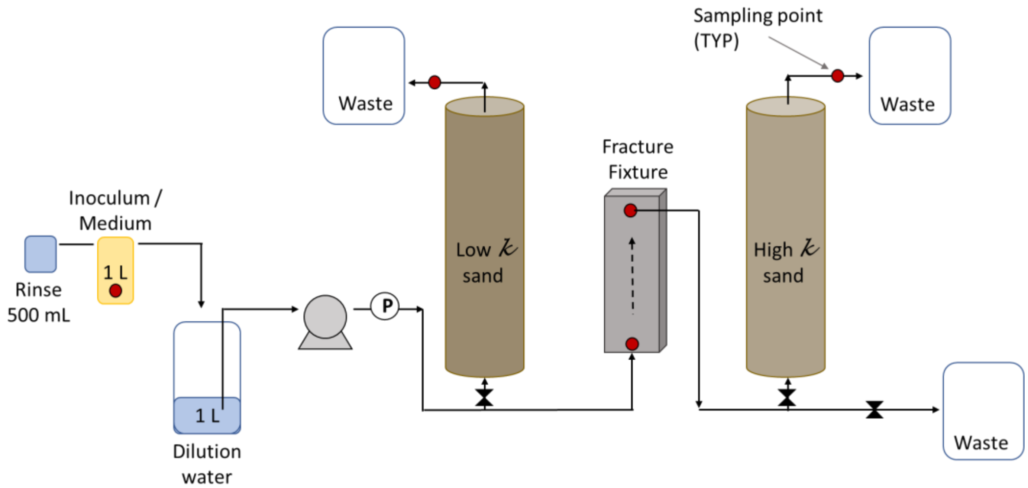

Figure 1. Schematic of the laboratory-scale reactor used to model the Rexing field demonstration.

After 10 pulses of *Sporosarcina pasteurii* inoculum and 19 pulses of calcium medium, injection pressure exceeded system limits and the experiment was terminated. The flow-to-pressure ratio of the system, defined as the flow rate (mL/min) divided by pressure (psi), decreased from 95.5 to 0.98 mL/(min*psi), a reduction of two orders of magnitude over the four days of the experiment (Figure 2). It appeared that the majority of the mineral formation occurred in the higher permeability sand, the model for the thief zone sandstone formation at the Rexing #4 well.

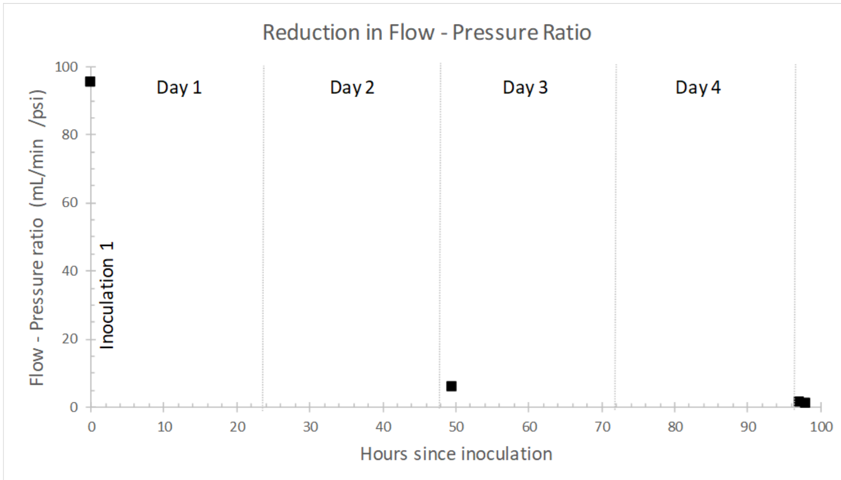

Figure 2. The ratio of flow to pressure in the lab-scale reactor, an indication of the system permeability, decreased by two orders of magnitude over four days of inoculum and calcium medium injection.

The laboratory efforts mimicked the design of the Rexing #4 well field injection strategy where it was planned to use pulsed injection with a bailer delivery method. Additional analysis of the cemented sand columns and the mineral formed in the fracture fixture are currently underway and will be reported in the next quarter.

Rexing #4 Field Experiment

The Rexing #4 well, located near Cynthiana, IN, has historically been used to sweep residual oil to production wells until injection pressure was lost presumably due to a fracture in the cement associated with the wellbore. Well logging data suggested that rather than entering the target formation, injectate was traveling up the casing-bore hole annulus through defects in the well cement to a sandstone thief zone approximately 30-50 feet above the target formation. The results of temperature logging suggested that the fluid had travelled from the perforations between 2284 and 2294 feet bgs back up alongside the casing into the sand body from 2250-2230 feet bgs. The goal of the field demonstration project at the Rexing #4 well was to use MICP to reduce permeability in the thief zone sand and cement defect to restore injection pressure. The advantage of using this well for the second demonstration was the presence of oil in the formation, which makes this sealing experiment more applicable to a real-world oil field technology. Additionally, the Rexing #4 experiment was the first time MSU's new DOE-funded mobile laboratory was used for a field demonstration of MICP.

The key findings were:

1. From temperature logging prior to the MICP treatment there was indication of fluid travelling from the perforations along the back side of the casing and up into the sand (thief zone) at 2230-2250. A channel was presumed to be fractured cement from approximately 2280-2250 feet bgs.
2. Injection pressure and –flowrates were monitored during the MICP injections; and over the course of the experiment, the flow to pressure ratio was reduced 70%.
3. When the tubing was removed from the well there was considerable calcium carbonate build-up on the tubulars.
4. The injection test conducted overnight prior to the second temperature log indicated the pressure flow relationship was still close to that at the end of the experiment with the final rate of 2.25 GPM at 740.5 psi.
5. The second temperature log after MICP treatment showed fluid exiting the perforated interval and the bulk of flow staying contained in an area within a few feet of the perforations.
6. After re-installing the tubing, injection was restarted with the flow rate of 2.25 GPM at 750 psi consistent with where it had been prior to logging.
7. Sometime after injection was restarted on 12/21/2017 at about noon, the pressure declined down to 600 psi by the following morning and injection rate slowly rose during the following week until freezing up. Further injection and possibly another temperature log is required to evaluate the final outcome of the field experiment.

Conventional oil field methods were used to deliver MICP-promoting fluids downhole to the treatment zone approximately 2288 feet below ground surface (bgs), including a slickline dump bailer and injection of water through the tubing string to push the biomineralization fluids into the fractured cement and/or thief zone. The injection strategy consisted of one 15 L bailer of microbial culture followed by two bailers of calcium medium which was then repeated. After a total of 25 inoculum injections and 49 calcium solution injections, the flow to pressure ratio of the system had decreased from 10.4 x 10^{-3} gpm/psi to 3 x 10^{-3} gpm/psi, a reduction of approximately 70% (Figure 3). On day four, after several failed bailer deliveries, it was observed that there was a reduction in injection pressure. The cause of the pressure loss was unknown, though possible explanations include breaking down the newly formed MICP mineral seal, a new fracture formed in the wellbore cement, or channeling in the sandstone. The flow-to-pressure ratio again decreased on days five and six after the day four pressure drop.

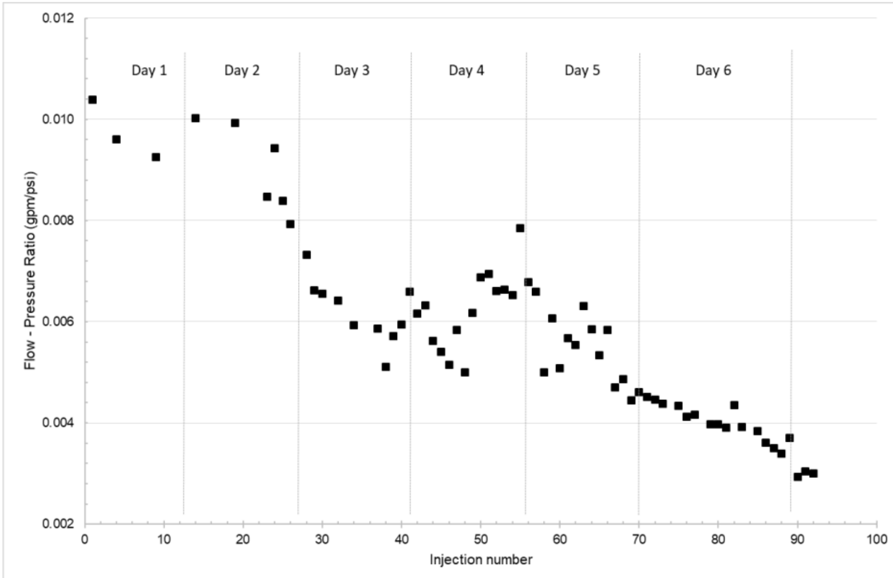

Figure 3. The flow-to-pressure ratio, an indication of apparent permeability in the Rexing #4 well, decreased by approximately 70% over six days of injection of MICP-promoting fluids.

Pumping tests conducted approximately two weeks after the end of the field experiment yielded flow to pressure ratio values consistent with those recorded at the end of the experiment. The Rexing #4 well was returned to use as an injection well on December 22, 2017. However due to the frigid temperatures the well froze and has not been injecting since. Oil production data collected over the coming months are expected to reveal the extent to which sweep water injected into Rexing #4 is accessing the target formation. Several weeks of injection and additional temperature logging will be required to determine the fate of the injected water.

An additional temperature log was acquired over the zone of interest after the MICP treatment experiment. In this temperature logging, cool fluids are injected into the well and then the temperature logging tool was lowered down into the well every 30 minutes. The change in temperature was monitored as the strata slowly warmed the well casing and fluids toward equilibrium. The spacing of the lines indicate the rate at which the temperature recovers following injection of a colder fluid. More closely spaced lines indicate higher injection volumes and slower temperature recovery. More widely spaced lines, suggest that less water was injected into the region and temperature recovery is dominated by the thermal gradient of the well. The temperature log conducted in October 2017, before the MICP treatment, shows closely-spaced, near vertical lines from each pass of the instrument between the region of 2250-2280 ft bgs which was considered the channel connecting the perforated zone with the thief zone (Figure 4, left). The post-MICP temperature log from December 2017, however, shows more widely spaced temperature values between the passes of the instrument (Figure 4, right). From preliminary analysis, it appears that less fluid was traveling into the channel between 2280 and 2250 feet below ground surface. This suggests that MICP treatment indeed sealed or partially sealed the leakage pathway.

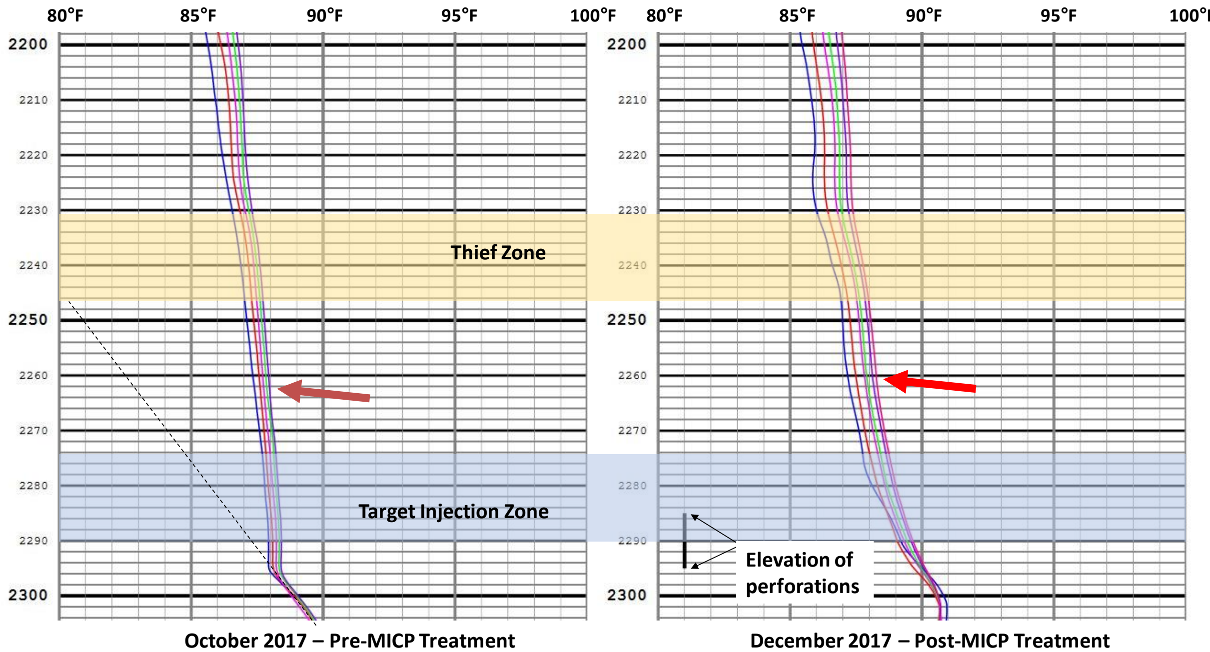

Figure 4. Temperature logs collected pre-MICP (left) show tighter spacing of the temperature log lines (orange arrow) indicating fluid flow in a channel between the perforated zone and the thief zone. Post-MICP (right) shows reduced fluid flow in the region of the channel after treatment, indicated by the wider spacing of the measurement passes (red arrow).

After completion of the injection tests and the temperature log, the tubing string was pulled from the well. Jim Kirksey (SLB) noted a significant build-up of calcium carbonate materials on the pup joint which was located in the region where the bailer dumped the biomineralization promoting fluids (Figure 5). This material was scraped from the pup joint and sent to MSU where analysis is ongoing. The observation of this build-up suggest that calcite precipitation can be promoted under these field conditions including in the presence of oil.

Figure 5. Calcium carbonate was detected on the downhole tubing (observed as the bumpy coating on the tubing (left and middle). The material was collected and sent to Montana State University for analysis (right).

Mobile Mineralization Operations Center Development

The mobile laboratory was delivered to Montana Emergent Technologies (MET) in August 2018. MET completed the construction and addition of shelves, desk space, and water system prior to its use in the Rexing #4 field experiment. The trailer was mobilized to Indiana in November 2017 and was successfully used for the field experiment performed at the Rexing #4 well. The new DOE-funded mobile laboratory (Figure 6) provided a flexible workspace in which to carry out the various activites required over the course of the field demonstration, including laboratory analyses, growth of microbes, media preparation, planning and data entry, and secure storage of equipment and supplies. Based on previous field experiences at the Gorgas well in Alabama, it was estimated that nine injections could be completed each day. In the Rexing #4 experiment, however, 12-15 injections were completed on days two through six. This enhanced productivity was attributable in part to the mobile lab, as well as to the efficiency of the team members operating the pumps at the wellhead and the slickline crew.

The field team was also able to enhance microbial growth rates in the large volume cultures in part by selectively heating the operations room at the back of the trailer. During the experiment, as the team worked in the operations room, further modifications to the space were discussed. Potential modifications include built-in counter and storage space, a hopper-type system for handling of dry chemicals, larger liquid storage tanks with integrated mixing and aeration systems, as well as an improved ventilation system.

Figure 6. The central lab space in the mobile laboratory provided adequate work and storage space for the necessary sampling and analysis of media solutions and microbial cultures. The operations room, visible through the doorway in the left photo, was used to cultivate large inoculum batches, mix calcium medium for injection, weigh chemicals, and store equipment and supplies.

Opportunities for training and professional development

No activity to report.

Disseminating results to communities of interest

No activity to report.

Planned activities during the next reporting period

We plan to complete the analysis of the field experiment data and additional build out of the mobile operations center. We are preparing three publications related to this work.

Products

No activity to report.

PARTICIPANTS & OTHER COLLABORATING ORGANIZATIONS

Other organizations involved as partners

Schlumberger (SLB). SLB is providing matching support for this project. During this reporting period, Jim Kirksey and others from SLB planned and participated in the second field demonstration.

Southern Company (SC). SC is providing matching support for this project. Dr. Richard Esposito of SC, identified and secured the 1493 m (4915 foot) deep well (Gorgas #1 well, Walker County, Alabama) which was used for the first MICP field test.

Montana Emergent Technologies (MET). MET attended meetings where discussion surrounded the current laboratory efforts, the mobile operations center, and the field planning. MET participated at a very high level in at the Rexing #4 field test and will contribute to the analysis of the field test results and the completion of the trailer build out.

University of Alabama at Birmingham (UAB). Dr. Peter Walsh is in charge of the UAB Core Testing Laboratory. He will continue conducting core testing activities throughout the duration of this project.

University of Stuttgart. Dr. Rainer Helmig, Director of the Institute for Modelling Hydraulic and Environmental Systems (IWS), and Dr. Johannes Hommel, postdoctoral researcher, are project collaborators at the University of Stuttgart. They along with other colleagues have developed a reactive transport simulation model, referred to herein as the Stuttgart MICP model, that has been integrated with previous laboratory and field research. This model was successfully used to design the Gorgas field test in April 2016 and was also used to model the injection strategy that was used at Rexing #4.

IMPACT

As reported previously, the results of the April 2016 Gorgas MICP sealing test were positively received by Mr. Jim Kirksey and Mr. Wayne Rowe of Schlumberger. In addition, the success of the experiment has been disseminated through news articles to increase the audience aware of the technology. An additional news article is in preparation about the mobile laboratory and impacts of the wellbore integrity work.

Dollar amount of award budget spent in foreign country(ies)
Not applicable.

CHANGES/PROBLEMS

As of this reporting period there are no problems to report. As noted above, the project milestone deadlines were revised due to the budget period 1 no cost time extension.

SPECIAL REPORTING REQUIREMENTS

At this time there are no special reporting requirements.

National Energy Technology Laboratory

626 Cochrans Mill Road
P.O. Box 10940
Pittsburgh, PA 15236-0940

3610 Collins Ferry Road
P.O. Box 880
Morgantown, WV 26507-0880

13131 Dairy Ashford Road, Suite 225
Sugar Land, TX 77478

1450 Queen Avenue SW
Albany, OR 97321-2198

Arctic Energy Office
420 L Street, Suite 305
Anchorage, AK 99501

Visit the NETL website at:
www.netl.doe.gov

Customer Service Line:
1-800-553-7681