BEST OF BOTH WORLDS FROM PROPPANT DISTRIBUTION TO FRACTURE DIVERSION— AN INTEGRATED SOLUTION TO OPTIMIZING STIMULATED RESERVOIR VOLUME

Vidya S. Bammidi, Sarkis Kakadjian, Scott Thiessen and Jose Garza
Keane Group

ABSTRACT

Horizontal drilling and the need for effective completion techniques has given birth to a wide variety of solutions in North American oil and gas plays. For many operators, it has become a top priority to optimize proppant distribution using buoyancy enhancer additives and to achieve fracture diversion with clean solutions that do not require intervention. At the heart of these initiatives is the Permian Basin, which is being revitalized through the use of intelligent completion technologies to make those priorities a reality.

In this paper, a two-solution approach is proposed as a customizable and integrated fluid system that helps improve proppant distribution, deepen proppant penetration within the complex fracture network, increase proppant pack volume, and increase maximum proppant concentration. By improving proppant placement and increasing the stimulated reservoir volume, operators can enhance conductivity of the fracture network, resulting in improvements to initial and long-term production.

TARGETING UNDERSTIMULATED ZONES THROUGH THE USE OF DEGRADABLE DIVERTING AGENTS

The main objective in diversion operations has been to distribute treatment fluids uniformly in target zones. Many degradable materials have been developed and pumped in the past including benzoic acid that enables the material to dissolve either in aqueous or hydrocarbon media. Recently, there has been broad use of aliphatic–polyester-based diverting materials that self-degrade in aqueous fluid whether in neutral, acidic, and basic conditions. Products in variety of shapes including fibers, pellets, flakes, and granulates have been tested and used to suit these different applications (Allison, 2011; Reddy, 2013).

The present work includes selection and testing of experimental degradable diverting agents (DDA) to be used in temperatures ranging from 115–>300°F. As with any application, many evaluated products fell short of their expected performance and were excluded from the remaining qualification testing. The DDAs selected were classified by specific temperature ranges of 115–160°F, 160–200°F, 200–250°F, and 250–290+°F to find products that performed well within these temperature conditions. It has been estimated that, on average, 29.6% of all perforation clusters are not contributing to production. When six or more perforations clusters are employed per stage, up to 46% of perforations were found not to be contributing to production (Miller, 2011). Because of these untreated or under stimulated perforations or clusters, diverting agents have increased in usage for new completions to target and limit the sections that are being bypassed.

Experimental

Diverting agents must have the ability to move through obstacles and bridge off; sealing the desired perforation clusters. An argument can be made that one of the most important attributes of the diverting agents is the ability to move through a wide variety of wellbore configurations, including coiled tubing, tubing, sliding sleeve systems, and annular space. The products must also have the ability to be customized on the fly and adapt to the wellbore conditions. After initial testing of the available DDA products and evaluating the consistency of their degradation performance, three products were selected to serve at varying temperatures. **Table 1** lists selected products with their respective temperature ranges. These products self-degraded over a period of time in several hours to a couple of weeks depending on bottomhole temperature. **Figures 1–4** show the self-degradation curves for DDA-1, DDA-2, and DDA-3 at temperatures between 115 and 250°F using 5,000 mg/L NaCl brine being DDA-1and DDA-2 with catalyzer current materials pumped or tested for the Permian Basin. **Figure 5** illustrates images on the self-degradation leaving no insoluble residue which can allow the operator to bring the well onto production with no further intervention required for the DDA products.

Although the three DDA products degraded with a consistent performance, further product development was required to ensure that the products bridged off and maintained a 500-psi differential pressure. To test the products' ability to perform, a variety of mesh sizes were tested individually and in combination with one another. The particle sizes ranged from 10 to 100 mesh size distributions for the individual products. Various tests were conducted using single-sized particle distribution and found to perform poorly as a bridging agent during the slot model test. Further tests using a combination of two particle size distributions was found to be a significant improvement over the single-particle size distribution. Finally, adding a formulated and specific ratio of 10-, 20/40-, and 100-mesh particle distributions turned out to be the most effective. It was found that the larger particles bridge off at the fracture while the smaller particles begin to fill-in the void spaces. The finer 100-mesh particles pack off the remaining gaps. This testing and development led to a unique distribution of particle sizes with the ratio of particulates providing the required mobility. The particle distribution also provided the ability to bridge off in the unknown geometries of fractures, wellbore, and perforations found in refracture candidates. The unknown geometries, which present a unique set of problems for each well, have been generated in refracture candidates as a result of previous hydraulic fracture treatments and ensuing production.

The final ratio distribution was then submitted to the chemical supplier for production and tested in the R&D laboratory for confirmation. The new products with their unique particle distributions and carrier fluids were evaluated in the lab using a fluid loss cell with a slotted disc to simulate the fracture opening. The products were slurried and tested using 500 psi of differential pressure to determine their ability to seal at the fracture and hold under pressurized conditions. The products that formed a seal in less than 10 seconds and held the differential pressure were selected for further field trials.

Case Study

The DDA technology was taken to the Meramec shale in Mid Con to be tested in real-world applications. Pressure responses were observed, monitored, and recorded to determine the products' performance. **Figure 6** shows a successful application of DDA-1 with diversion stages indicating 4,010- and 4,298-psi differentials. The DDA-2 diverter system was pumped in an 8,796-ft TVD, 15,732-ft MD well that included a lateral length of 6,675 ft. The completion design called for a 28-stage hydraulic fracturing operation. Because it is difficult to break down the formation at the toe of such a long lateral, the first five stages were 200-ft stage intervals of the toe section that used four perforation guns to shoot clusters at 50-ft spacing; treating pressure was approximately 6,975 psi. The perforated lateral was the equivalent of two stages, which served to reduce stage count from 50 to 27 and eliminated plug and perf run between stages. This avoided more than 2.5 days of wireline operations. As a result, the operator brought the well on line earlier and increased production.

The DDA-1 diverter product was applied for the remaining stages, with the operator doubling the treated lateral length to 400 ft perforated with eight guns, eliminating 22 wireline runs. Stages 1 through 10 were treated using a 20-lbm crosslinked borate gel system; the remainder of the stages used 15- to 18-lbm crosslinked gels. All stages used 17,000 U.S. gal of slickwater pads. Stage 1 used a proppant slurry of 0.1–2.5 pounds of proppant added (ppa) per gallon of fluid; Stages 2–5 used 0.1–3.5 ppa; and Stages 6–28 used 0.5–5 ppa. The bottomhole temperature of the formation was 175°F.

BUOYANCY ENHANCER ADDITIVE PACKAGE

A new method to improve the transport of proppant in a slick water treatment has been developed. This method is referred to as buoyancy enhancer additive (BEA) based in a novel surfactant; it can impart a hydrophobic layer onto the surface of the proppant. The resulting adsorbed surfactant layer can attract air or nitrogen, which enables a microscopic gas bubble to surround the proppant particle and lower the relative density—therefore making the particle buoyant in water. During a slickwater treatment, gas can be introduced by co-injecting 5–20% nitrogen. Creating a buoyant proppant imparts a suspension mechanism that is not typically found in a conventional slick water. This suspension both carries sand without relying on rate-induced turbulence and increases the velocity across the top of a higher volume proppant pack, therefore improving creep- and saltation-related transport. As a result, proppant penetrates deeper into fractures, and vertical distribution of the proppant is improved. The use of BEA also enables greater maximum concentration of the proppant in the slurry and placed in the fracture. A visual depiction of the BEA-enhanced slick water versus a conventional system is shown in **Figures 7 and 8** (Kostenuk, 2010).

Experimental—Sand Suspension (Lab Atmospheric)
Simple laboratory bench top studies were performed to determine the efficacy of BEA treatment with various proppant types, sizes, and concentrations—and to optimize the best application methods of the additive. The method is to add a measured amount of proppant to 200 mL of water in a Waring laboratory blender and blend at a high rate for 120 seconds. The blending action entrains air from the atmosphere, simulating the injection of nitrogen. The air encapsulates the sand particles due to the nature of the adsorbed surfactant. **Figures 9** compares the suspension of 40/70 sand untreated and treated with the BEA, and **Figure 10** shows a microscopic image of BEA-treated sand.

Sand Suspension (Yard Test, High Pressure)
To determine if the buoyancy of the BEA-treated sand could be maintained at high pressures, a field test was performed using a high-pressure pumper connected to a vertical stand of pipe that consisted of three sample valves at the top, middle, and bottom (**Figure 11**). A choke was used to build pressure in the pipe stand to simulate pumping pressures during a fracture treatment. Tests were performed using conventional slickwater fluids with and without the BEA treatment. In both tests, the slurry was pumped through the testing apparatus for 5 minutes, after which the slurry was allowed to sit for 10 minutes in the column. Gas (air) bubble encapsulation was introduced by shearing the slurry at a high rate through an open tub. The proppant used during the testing was regular 40/70 sand; the pipe was pressured to 5,000 psi. The results of the high-pressure field testing are summarized in **Table 2**. As shown, the column containing the untreated sand slurry was over 91.7% settled at the bottom of the column, with only 8.3% sand suspended at the sample valve. On the other hand, the BEA-treated slurry resulted in 68.3% of the sand settled at the bottom while 31.7% of the sand remained suspended at the upper sample point. This indicates that even at expected fracturing pressures, the microcapsule gas bubble was able to maintain proppant buoyancy (Boyer et. al, 2014).

Flow Model
To compare the proppant transport of a conventional slick water fracturing fluid versus the BEA-treated slickwater, a flow model was used. As shown in **Figure 12**, the flow model consisted of transparent Plexiglass sheets that had a 0.25-in thick slot. The sheets were 8-ft long and 3-ft high. A 2 lb./U.S. gal slurry of 40/70 white sand in water was prepared with a 50-gallon blender. The slurry was then pumped into the slot at a rate of 60 U.S. gal/min. Gas was injected immediately after the pump to simulate approximately 5–10% N_2 addition by volume. The slurry was pumped for a period of 1 minute and was then displaced with clean fluid for 1 minute. The test was then shut in to observe the proppant pack. For the test with the BEA treatment, the additive was injected at a concentration of 2 gpt to the slurry (**Figure 14**).

Several observations were made during the flow model testing. While flowing, a significant amount of proppant was floating when the BEA treatment was used. However, a bank eventually still formed. This bank was significantly higher and more voluminous when compared to the conventional slick water (see **Figures 13 and 14**). The pack height when using the BEA was measured to increase by more than 40%. Additionally, the resulting dune appeared more porous than the harder packed dune observed with the conventional slick water.

It was also noted that 28% of the sand pumped was recovered at the discharge point of the model when using the BEA treatment, whereas only 20% of the proppant was recovered using the conventional slick water.

Regained Conductivity
A regained conductivity test was performed using the ISO 13503-2 recommended test procedures and equipment. Testing included a conventional slickwater blend containing 1 gpt friction reducer in 2% by weight potassium chloride (KC1) brine compared with a BEA-modified slickwater blend containing 1 gpt

friction reducer and 2 gpt BEA additive in 2% KC1 brine. The test cells were loaded with 2 lb./ft^2 of 40/70 white sand between Ohio sandstone wafers. Initial conductivity readings were taken at 1,000-psi closure pressure over a stabilization period of 24 hours (using the test fluid). After stabilization, the width was determined and then the closure stress was incrementally increased. Conductivity and width were recorded at 1,000; 2,000; and 6,000 psi. A simulated reservoir temperature of 150°F was used for all testing.

Regained conductivity measured with the BEA-modified slickwater blend showed significantly improved performance when compared with the unmodified blend (**Figure 15**). Even at the highest closure pressure of 6,000 psi, the modified blend had a conductivity of 412 mD-ft as compared with 261 mD-ft for the unmodified blend. This is an increase of 58%. A possible explanation for this could be the increase in proppant bed width observed with the modified proppant versus unaltered proppant.

Case Studies

In more than 6,000 stages pumped in Canada, efficiencies were observed with a modified pumping schedule and the use of BEA-treated proppants. In the Cardium formation of the Western Canadian Sedimentary Basin, average stimulation time was reduced dramatically as a result of improved fracture placement. Fracture sand-off frequency was reduced despite a more aggressive pumping schedule. Using a more aggressive proppant pumping schedule, water volumes were reduced on a per-ton proppant basis by 17%. In the event of a screenout, less energy was required to carry BEA-treated proppant out of the wellbore during flowback to test vessels. This reduced the need for coiled tubing services to clean out the wellbore. These efficiencies equated to an average reduction of 23% in total completion costs. The average cumulative production for BEA-treated proppants has shown a 35% increase in BOE for operations in the Cardium formation (Boyer, 2014).

In the US, the BEA treatment has been implemented in 9 wells (130 stages) in major basins including 1 well in the Permian as per **Figure 16**.

CONCLUSIONS AND RECOMMENDATIONS

Proppant distribution and fracture diversion technologies have been extensively implemented in major basins across North America—proving and repeating results in field applications.

The presented operations in Canada and the Mid-Con are representative custom completion designs for the incorporation of buoyancy enhancer additive for proppant distribution and diverter technology for effective targeting—both to achieve the goal of optimum pounds of proppant per linear foot. The use of this formula enables operators to deliver treatments directly into understimulated zones and transport the proppant even deeper into the fracture network. This combination of benefits can be applied in a wide variety of formation types, including those with low temperature. Applied in West Texas, it is believed that a similar integrated solution would prove to extend the life of wells in the Permian Basin. Customized completion designs will continue to be implemented and measured, providing the production data needed to support a long-term study in the Permian.

REFERENCES

1. Allison, D., and Shawn, C. Restimulation of Wells using Biodegradable Particulates as Temporary Diverting Agents. Paper presented at the 2011 Canadian Unconventional Resources Conference held in Calgary, Alberta, Canada, 15–17 November 2011.
2. Reddy, B.R., Cortez, C., Activator Development for Controlling Degradation Rates of Polymeric Degradable Diverting Agents. Paper presented at the 2013 International Symposium on Oilfield Chemistry held in the Woodlands, Texas, USA, 8–10 April 2013.
3. Miller, C., Walters, G., and Rylander, E., Evaluation of Production Log Data from Horizontal Wells Drilled in Organic Shales. Paper presented at the 2011 North American Unconventional Gas Conference and Exhibition held in the Woodlands, Texas, USA, 14–16 June 2011.
4. Kostenuk, N., Browne, D., (2010). *Improved Proppant Transport System for Slick Water Shale Fracturing,* Calgary Alberta, CSUG, SPE 137818
5. Boyer, Jeff, O'Neil, Bill, Maley, Darren, (2014). Chemically Enhanced Proppant Transport, Amsterdam, Netherlands, SPE ATCE 2014, SPE 170640.
6. Maley, D., Boyer, J., O'Neil, B., Zhang, K., (2014) Surface Modification of Proppant to Improve Transport and Placement, Kuala Lumpur, Malaysia, IPTC-17806-MS

Table 1. DDA products selected for testing, with their respective temperature ranges.

Degradable Diverting Agent, DDA	
Product	Temperature Range
DDA-1	160-200° F (71-93°C)
DDA-2	200-250°F (93-121°C)
DDA-2 w/ Catalyzer	115-160°F (46-71°C)
DDA-3	250-290°F (121-143°C)

Table 2. Sand suspension yard test in high pressure (5,000 psi).

	Sand Above Settling Point	Sand Settled at Bottom
Sand Suspension	8.3%	91.7%
Sand Suspension with BEA	31.7%	68.3%

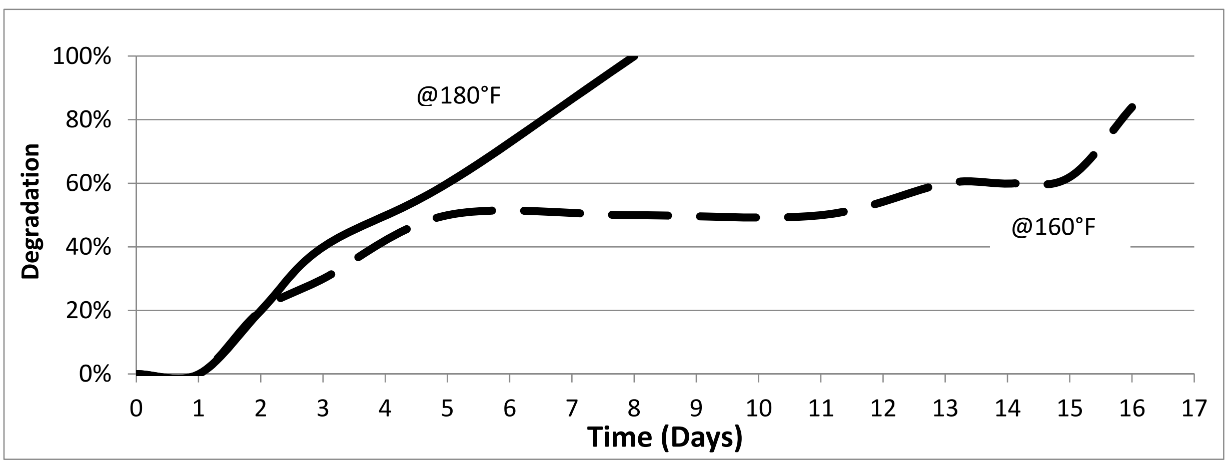

Figure 1 - Self-degradation curve of DDA-1 at 160 and 180°F.

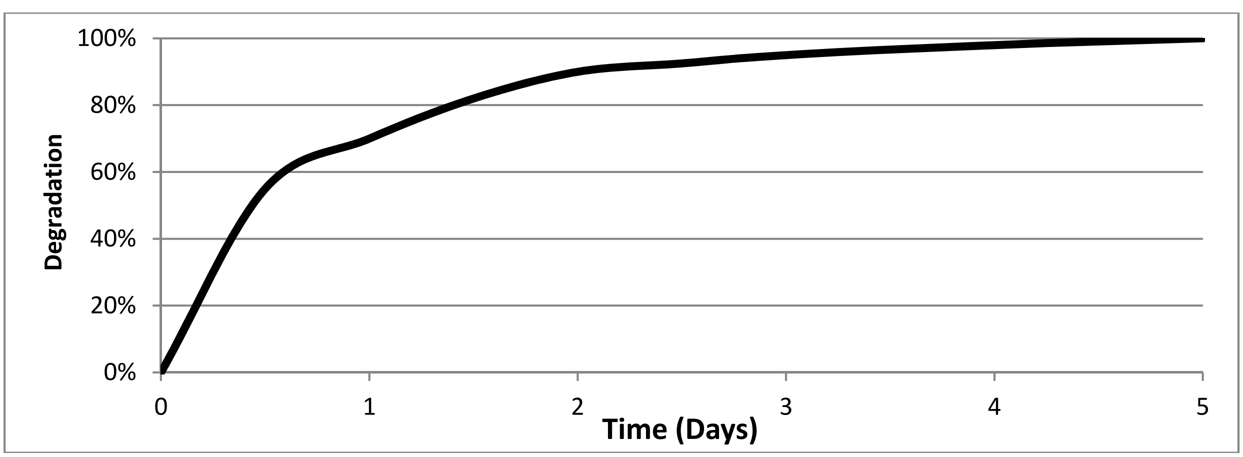

Figure 2 - Self-degradation curve of DDA-2 at 200°F.

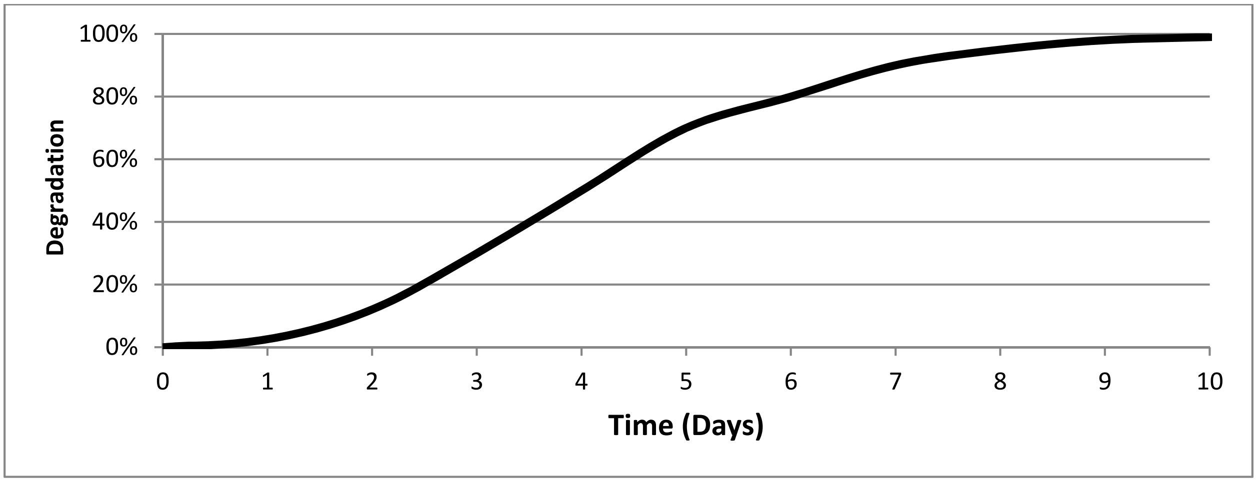

Figure 3 - Self-degradation curve of DDA-3 at 250°F.

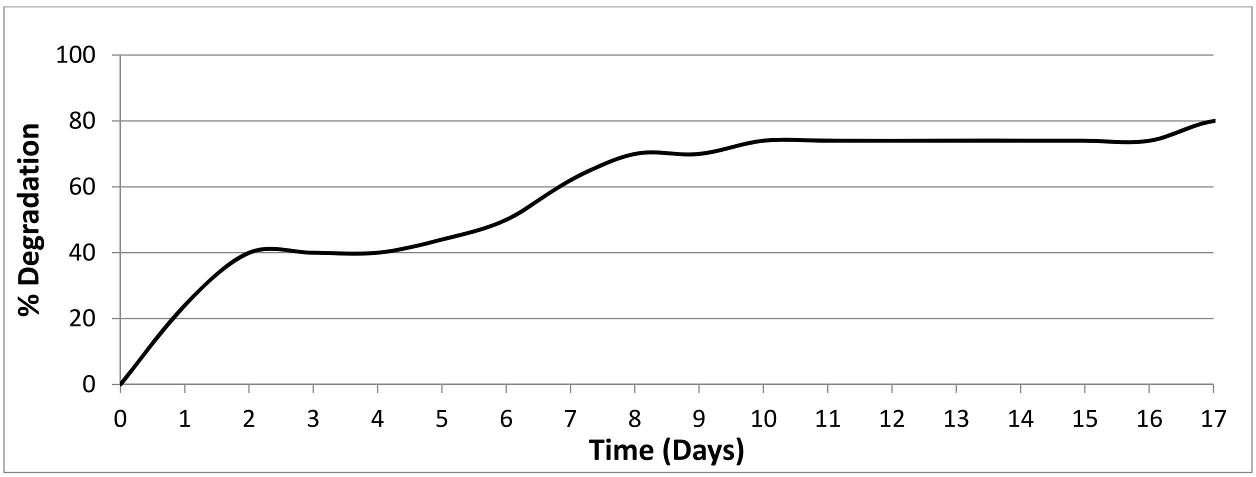

Figure 4 - Self-degradation curve of DDA-2 w/ catalyzer at 115°F.

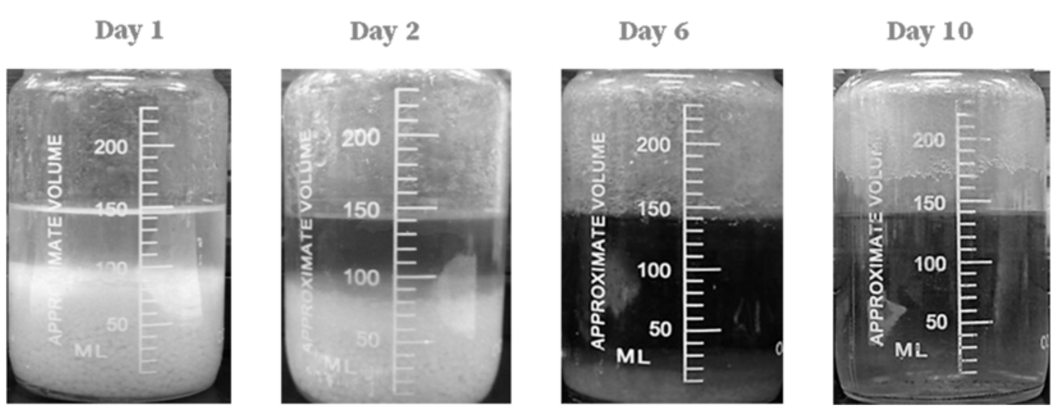

Figure 5 - Progressive self-degradation of DDA-3 at 250°F.

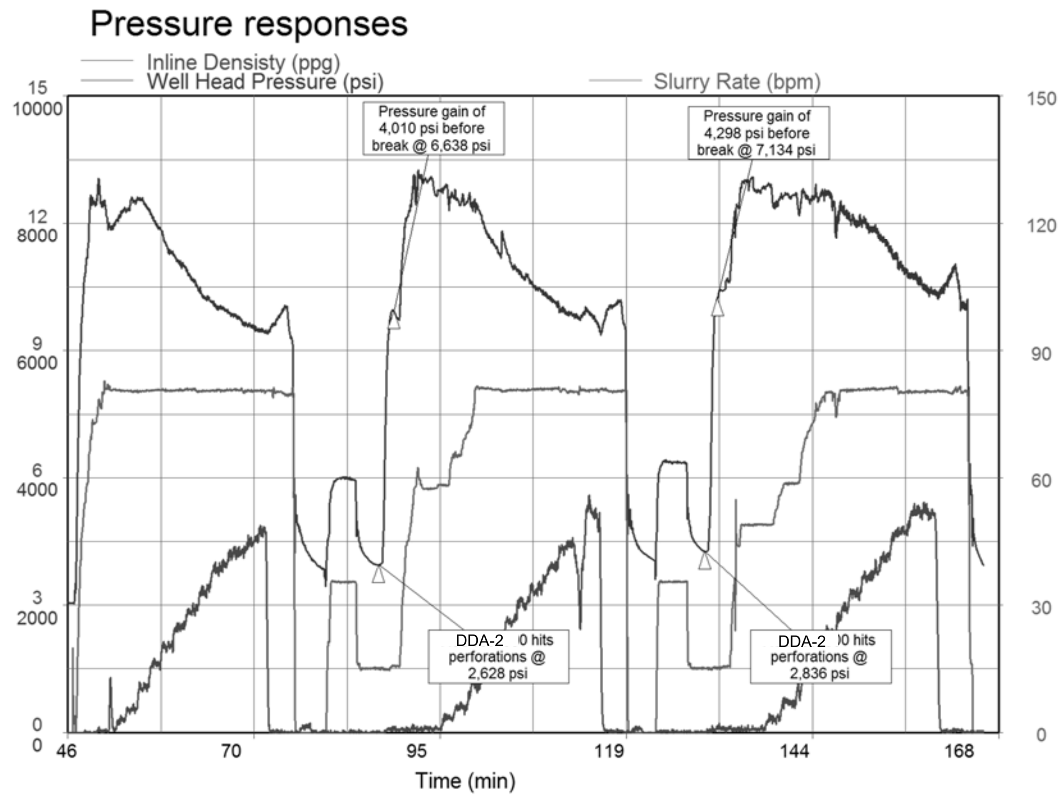

Figure 6 - Pressure response on the use of DDA-2.

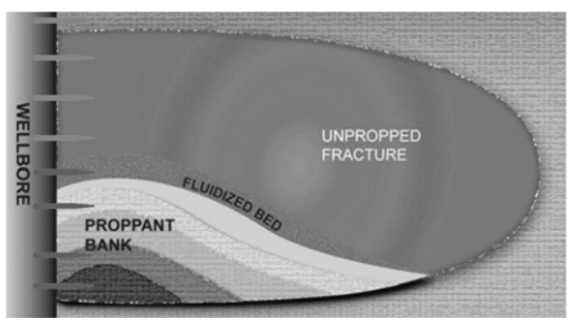

Figure 7 - Modified (Boyer et.al 2014). Light gray perforations are nonstimulated. Dark gray perforations are stimulated.

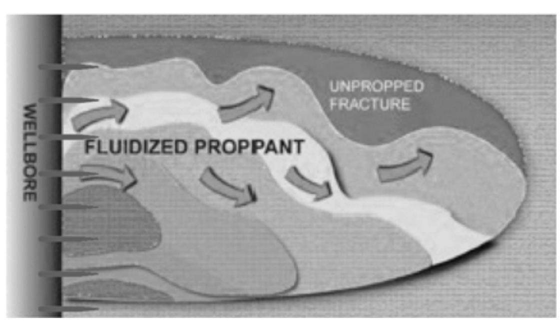

Figure 8 - Modified (Boyer et.al 2014). Integrated solution with longer half length and also better proppant distribution.

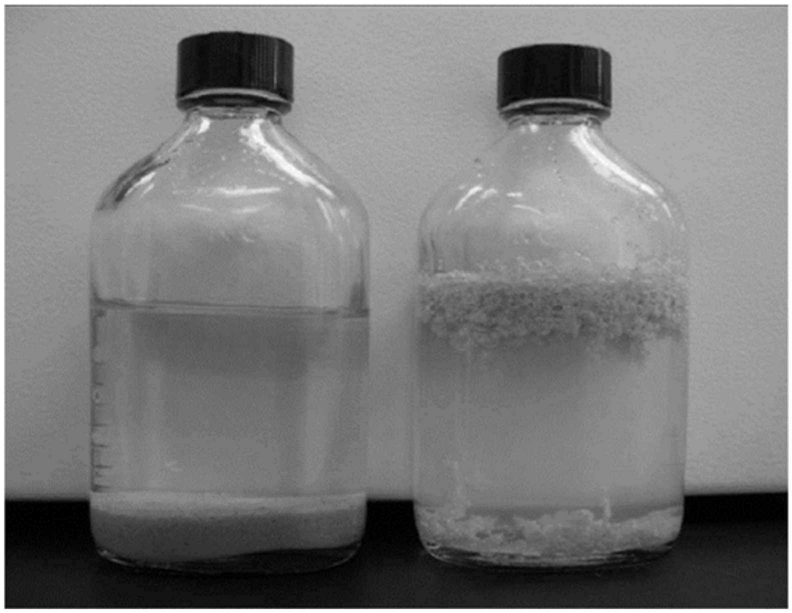
Figure 9 - Slickwater (left) and BEA-treated 40/70 sand (right) in 1.7 ppa.

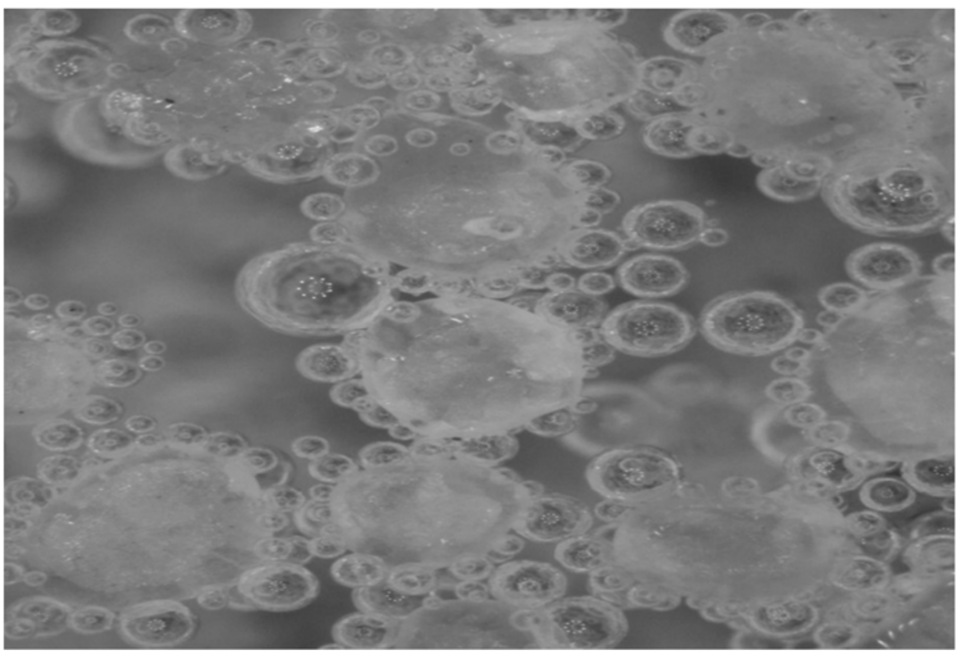
Figure 10 - Microscopic image of 40/70 BEA-treated sand.

Figure 11 - Vertical stand of pipe and sample valves for high-pressure suspension test.

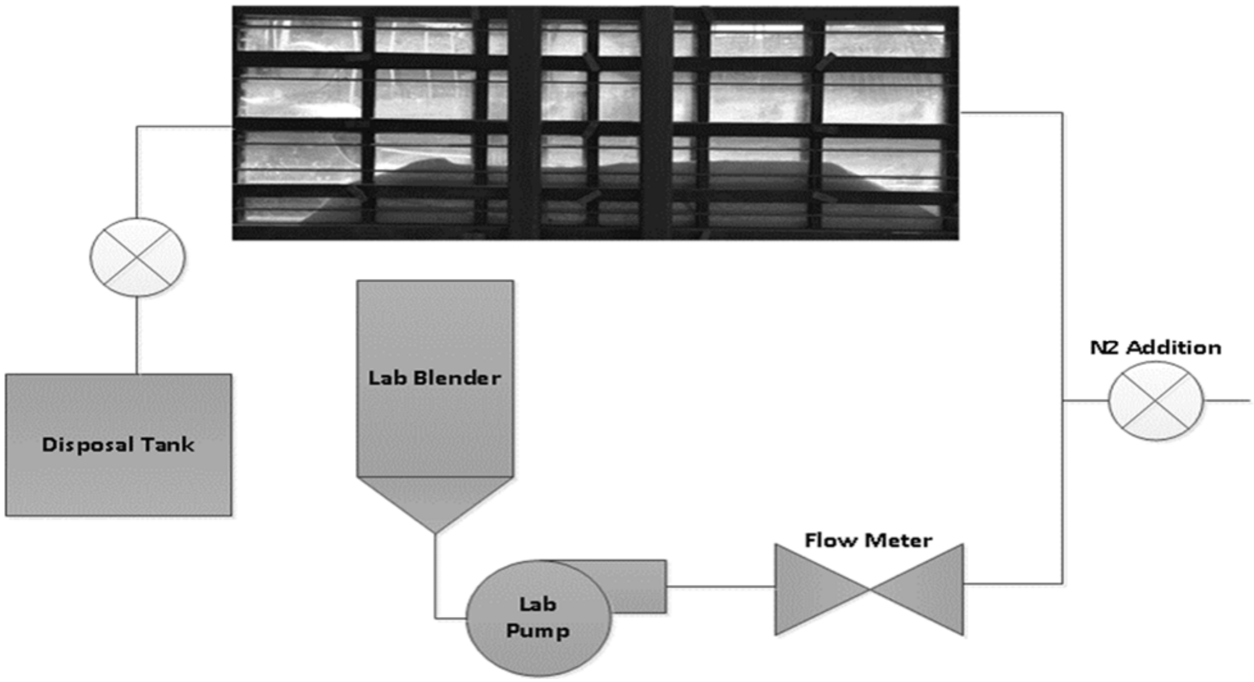

Figure 12 - Flow model setup.

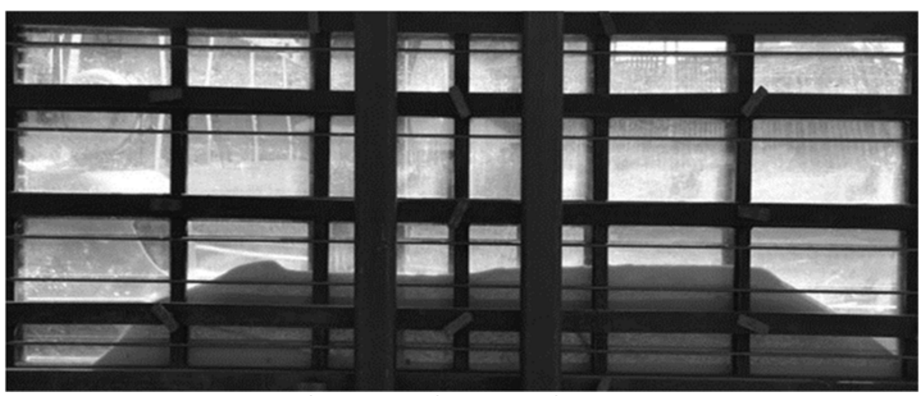
Figure 13 - Slickwater fracturing fluid with nitrogen.


Figure 14 - BEA-treated slickwater fracturing fluid with nitrogen.

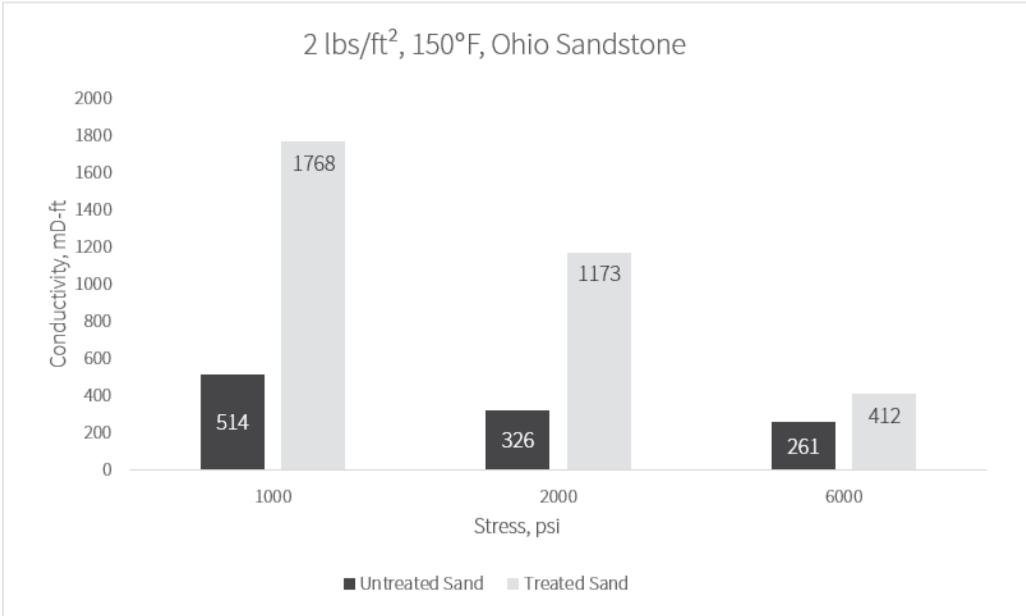

Figure 15 - Conductivity untreated and BEA-treated sand.

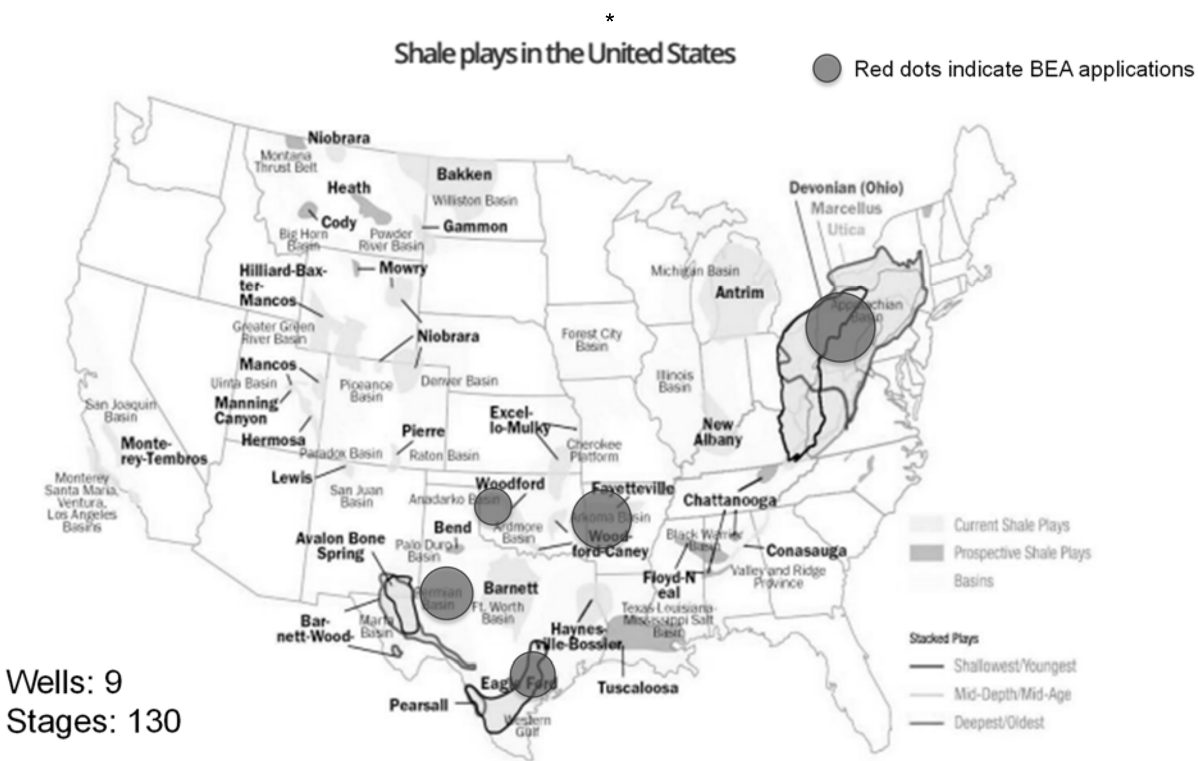

Figure 16 - BEA-treated slickwater applications in the US.