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Field Trial Evaluation on a Hydrocarbon-Free Friction Reducer

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Abstract

The waterfrac hydraulic fracturing method of hydraulic fracturing stimulation typically involves pumping water at a high rate into the reservoir to generate high pressure to crack open the formation. During this process, a friction-reducing agent is generally used to maximize the pumping rate capability using the available horsepower. Traditionally, a liquid form-friction reducer (FR), in which a high-molecular-weight polyacrylamide is carried in an oil-external emulsion, is used. However, in an effort to further reduce the need for hydrocarbons in additives, a dry FR additive was developed. During a previous study, a carbon-free dry FR was successfully developed during laboratory and pilot scale tests.

This paper presents data from two field trials of this dry FR performed in the Haynesville shale and Cotton Valley formations. Successful deployment of this hydrocarbon-free FR was achieved throughout several stages. More specifically, no hydration issues were observed, confirming observations from both laboratory and pilot scale studies. Tests were performed using a liquid form FR and the dry FR back-to-back during the same treatment stage, which provided a direct comparison of their friction reduction performance. The dry FR concentration optimization was determined for the well in the Cotton Valley formation. It showed a superior performance compared to a liquid form of this FR at the same active polymer loading, with an average decrease of 3.5% in treating pressure compared to the liquid form. Additionally, approximately 73 gal. of hydrocarbon was eliminated using the dry form of this FR during the field trials. This would potentially eliminate approximately 3,000 gal of hydrocarbon for these two wells if the dry FR was used throughout all of the stimulation stages. Moreover, heightened safety concerns with respect to using the dry FR on location have been identified and will be discussed.

Introduction

Since its first successful operation in the Cotton Valley formation during the 1990's, waterfrac stimulation treatments have become a popular stimulation method for unconventional developments (such as tight gas, shales, and coalbed methane). Its advantages compared to using conventional crosslinked gel fracturing include potential cost savings, the potential for reducing fracture damage, and it might provide a more complex fracture because of the higher pumping rate[1]. Because of the high energy dissipation associated with the high pumping rate (typically on the order of 100 bbl/min) used in waterfrac stimulations, a FR is usually used to help minimize pipe frictional energy loss during the stimulation process. Using a FR could either help increase the pumping rate under the same horsepower, or decrease the wellhead pressure while maintaining the pumping rate.

Currently, high-molecular-weight polymers are commonly used as FRs, which are in the form of liquid emulsion in most applications. The active polymer is carried inside water droplets, which are dispersed within the continuous oil phase. To maintain a stable liquid emulsion and reach instant inverting of the active polymer as soon as it contacts the fracturing fluid, the FR is usually designed to contain less than a 50% active polymer, while the remainder consists of mineral oil used as a carrier. This feature is the primary drawback of the liquid emulsion FR because it results in thousands of gallons of mineral oils pumped downhole Other drawbacks of using the liquid emulsion FR include the potential of freezing the FR solution, as well as settling and/or gelling during severe winter conditions. On the contrary, the dry FR functions by surrounding the friction reducing chemical with salt, which allows it to be transported and handled without the hydrocarbon carrier fluid. Thus, it does not have these potential risks.

This paper presents an extensive experimental study of this dry FR during both laboratory and pilot scale tests. An excellent friction performance was observed compared to the liquid emulsion FR. Field trials of this dry FR in the Haynesville shale and Cotton Valley formations are also presented and discussed.

Experimental

Material

The dry FR material used during the present study is polyacrylamide powder, with a mixing at approximately 30% by weight with salt. The active polymer is in the form of fine powder, which allows rapid hydration in water. The salt, acting as the carrier, further enhances the active polymer hydration. This dry FR targets fresh water and low total dissolved solid (TDS) (up to 100,000 pm).

Laboratory Test

The friction performance of this dry FR was evaluated using a friction loop in the laboratory. In principle, the friction reduction is calculated in reference to the baseline of the freshwater pressure drop in the same pipe with the same flow rate. It can be expressed as follows:

$$\%\mathrm{FR} = 1 - \frac{\Delta P_{measured}}{\Delta P_{water}} \tag{1}$$

where $\Delta P_{measured}$ and ΔP_{water} are the experimental pressure drop for fresh water with and without the FR, respectively. Indeed, the pressure drop for fresh water can be theoretically calculated when the pipe dimension and roughness are provided[5]. A calibration using fresh water was performed before the experiment, which was used to verify the apparent pipe diameter and determine the pipe roughness.

Fig. 1 presents a schematic illustration of the laboratory friction loop used for the friction performance evaluation during this work. The nominal inside diameter of the testing pipe was 1/2 in., and the distance between the two pressure sensors was 8 ft. Additionally, at least 4 ft of a section was allocated from the pressure sensors to each end of the testing pipe to minimize the end effect to the fluid streamline[6]. During field hydraulic fracturing application, FRs are only effective when the fluids pumped downhole are in turbulent regime. Because of the high pumping rates used in waterfrac stimulations, the increase in fluid temperature from the surface to downhole is generally very low. It is therefore reasonable to assume that the water fracturing fluid temperature remains the same as the surface. Thus, unless otherwise specified, all friction reduction tests during this study were conducted at ambient temperatures.

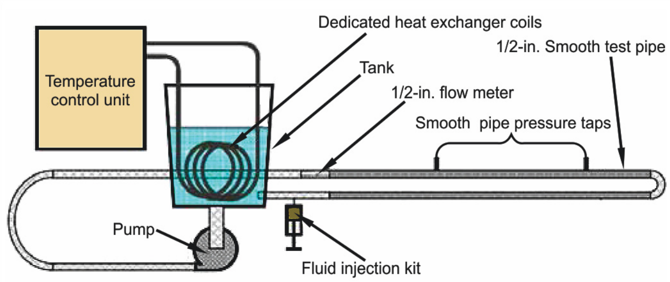

Fig. 1—Schematic illustration of the laboratory friction loop. The distance between two pressure sensors is 8 ft.

Fig. 2 illustrates a typical friction reduction performance of the dry FR obtained from the loop in Fig. 1. The behavior of a commercial liquid emulsion FR at the same active polymer loading is included for comparison. The flow rate was 10 gal/min, corresponding to a shear rate of approximately 3137 s^{-1}, which is similar to that of the fracturing fluid in the wellbore during a typical waterfrac stimulation treatment. By definition, the friction reduction was approximately zero for fresh water at the beginning. The friction reduction instantly increased to approximately 70% as soon as the FR was injected. This indicates that the dry FR can be hydrated as quickly as the liquid emulsion FR and thus achieves maximum friction reduction immediately. Very good friction reduction performance was observed for both FR materials. No mechanical degradation was observed for these FRs throughout 25 min of the testing period.

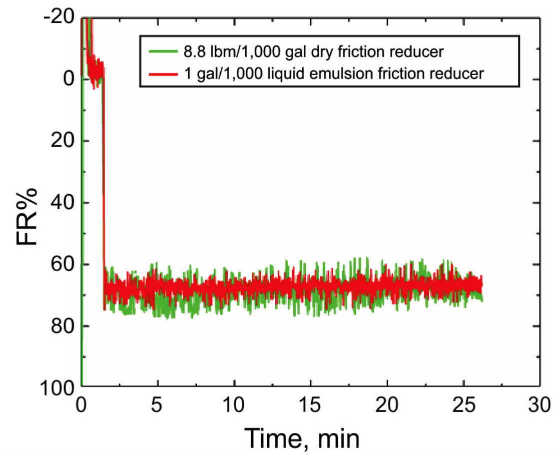

Figure 2—A comparison of the friction reduction performance between the dry FR and a commercial liquid emulsion FR at the same active polymer loading in fresh water.

Extensive laboratory tests for this dry FR were performed, including temperature effect, concentration optimization, and the chemical compatibility with commonly used waterfrac treatment additives. Results showed that the dry FR was comparable to the liquid emulsion FR under various conditions.

Pilot Scale Test

To further evaluate the performance of this dry FR, a pilot scale test was conducted with a pumping capability of 2 to 120 bbl/min. A testing pipe with a 4-in. inside diameter (ID) was used, while five pressure sensors were installed with separation intervals of 11.92, 16.25, 16.25, and 11.92 ft, respectively, as illustrated in **Fig. 3**. During this study, only the second and the fourth pressure sensor were used for friction reduction calculations, which provided a testing length of 32.50 ft. Using other pressure sensors provided the same results. **Fig. 4** shows a schematic illustration. Two types of tests were conducted—a circulating test to examine the FR's mechanical degradation throughout time and a single pass test to mimic the field waterfrac pumping process.

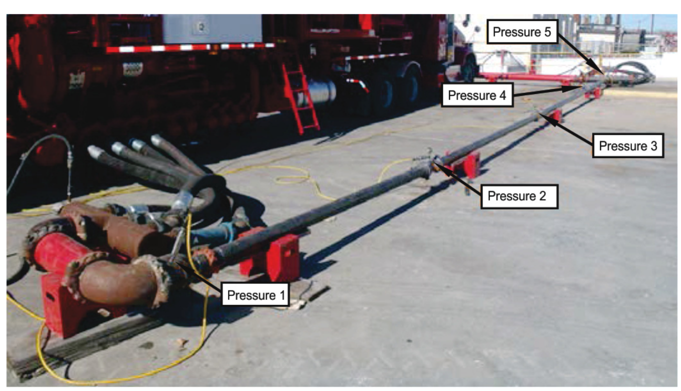

Fig. 3—Testing pipe (4-in. ID) with five pressure sensors.

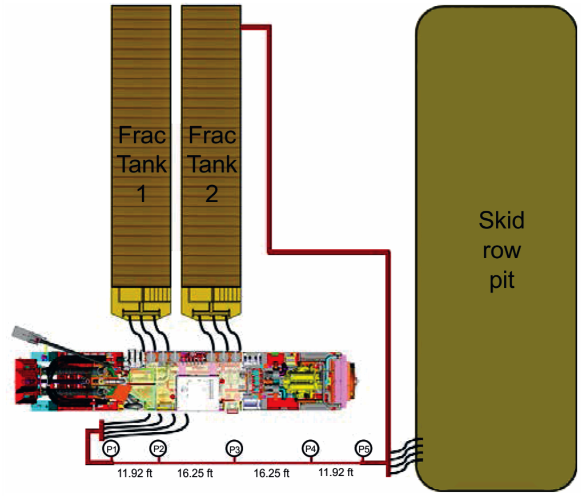

Fig. 4—Schematic illustration of the pilot scale test.

For the circulating test, only Frac Tank 2 was used, with the FR added into the blender tub. **Figs. 5 and 6** illustrate the performance comparison of the dry FR and a commercial liquid emulsion FR at the same active polymer concentrations. A good hydration and friction reduction performance was observed for the both dry FR and liquid emulsion FR. Mechanical degradation was only observed at lower FR concentrations, which also confirmed the laboratory data.

For the single pass test, the FR was continuously added into both tanks of water. The mixture was pumped at various flow rates through the testing pipe into the waste pit. Because the single pass experiment generates large volumes of waste, it was performed at pumping rates below 30 bbl/min. **Fig. 7** illustrates the friction reduction of the dry FR together with the data from the commercial liquid emulsion FR. The concentration was 4.4 lbm/1,000 gal for the dry FR and 0.5 gal/1,000 for the liquid emulsion FR, which represents the same active polymer concentration. Although the pumping rate used was not as high as a typical waterfrac stimulation treatment, a comparable friction reduction performance was observed for the dry FR and liquid emulsion FR.

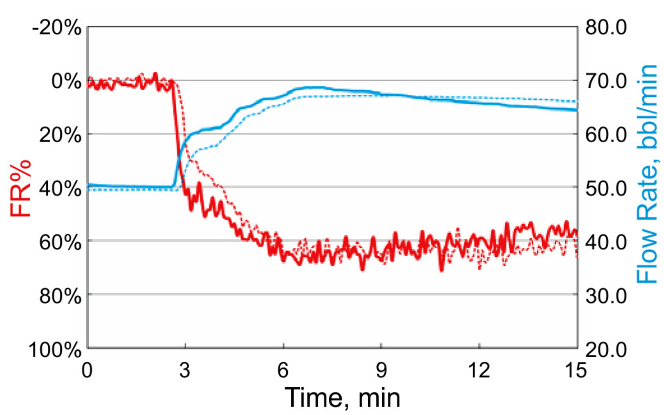

Fig. 5—Pilot scale circulating tests for the 2.65 lbm/1,000 gal dry FR (solid lines) and 0.3 gal/1,000 gal liquid emulsion FR (dashed lines), which have the same active polymer concentration.

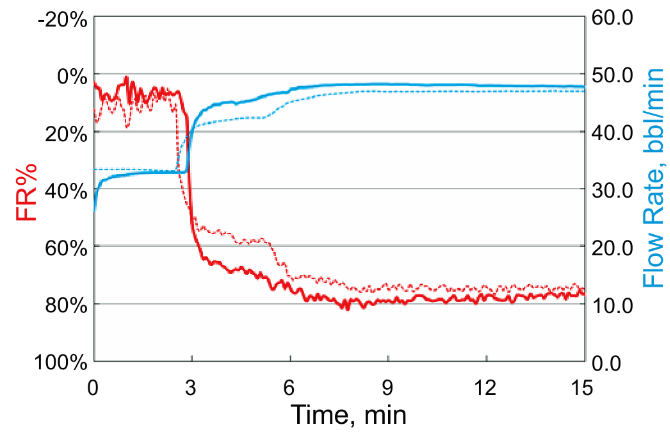

Fig. 6—Pilot scale circulating tests for the 4.4 lbm/1,000 gal dry FR (solid lines) and 0.5 gal/1,000 gal liquid emulsion FR (dashed lines), which have the same active polymer concentration.

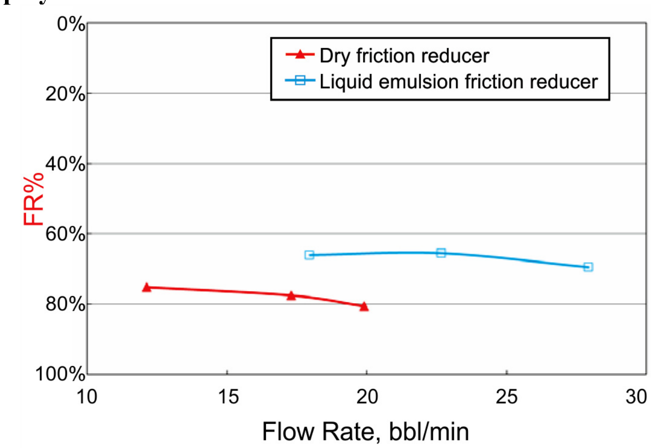

Fig. 7—Friction reduction as a function of pumping rate for the dry FR and liquid emulsion FR from the pilot scale tests.

Field Trials

Based on the promising results from the laboratory and pilot scale tests for the dry FR, two field trials using this product were performed. One was in the Haynesville shale formation and the other in the Cotton Valley formation. During both field trials, 55-lbm sacks of the dry FR were added into the blender with a built-in Acrison feeder. The Acrison feeder had been previously calibrated using a bucket test to obtain more accurate control of the dry additive concentration. During the laboratory and pilot scale tests, the commercial liquid emulsion FR was used for a performance comparison. **Table 1** summarizes the well information for these two field trials.

Table 1—Job Information of Two Field Trials

Formation	Bottomhole Temperature (BHT) (°F)	True Vertical Depth (TVD) (ft)	Design Rate (bbl/min)	Max Pressure (psi)
Haynesville shale	380	14,866	55	11,500
Cotton Valley	268	9,770	40	5,000

The first test occurred during Stage 13 of a Haynesville shale stimulation, with 100-mesh sand at a concentration of 1.6 lbm/1,000 gal. The liquid emulsion FR ran at 1 gal/1,000 gal, and the treating pressure stabilized at 11,384 psi at a constant slurry rate of 55.5 bbl/min. The dry FR was then introduced at a concentration of 8.8 lbm/1,000 gal, which was equivalent to the active polymer concentration in the 1 gal/1,000 gal liquid emulsion FR. Simultaneously, the liquid emulsion FR was backed down to 0.5 gal/1,000 gal instead of being cut completely. When the liquid emulsion FR was completely cut, the treating pressures began decreasing to a minimum of 10,902 psi. Following this, slight increases in the treating pressure were observed until it eventually stabilized at a level of 11,040 psi. This was 308 psi lower than the treating pressure when 1 gal/1,000 gal liquid emulsion FR was used (**Fig. 8**).

Similar results were obtained during other tests. Because of the ductile nature of this shale formation, the treating pressure was close to the maximum pressure of 11,500 psi. To further reduce the treating pressure or increase the pumping rate with the same horsepower, higher concentrations of the dry FR were tested. **Fig. 9** illustrates the treating pressure profile when switching from the liquid emulsion FR to the dry FR with 30% more loading. The treating pressure began to decrease from 11,211 psi, when the liquid emulsion FR was cut, to 10,604 psi after pumping one wellbore volume of the dry FR. This was a 607-psi drop in treating pressure compared to the treating pressure using 1 gal/1,000 gal liquid emulsion FR. The treating pressure decreased further to 10,496 psi, providing a 715-psi drop from the baseline of 1 gal/1,000 gal liquid emulsion FR. At the end of the test, the dry FR was cut, the liquid emulsion FR resumed, and the treating pressure recovered to the same level as before the introduction of dry FR.

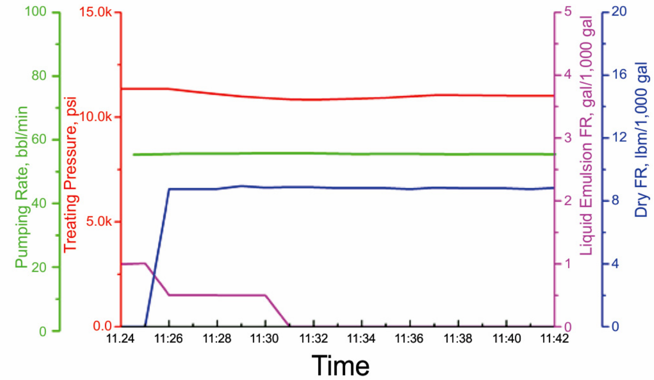

Fig. 8—Profile of the first test on the dry FR at 8.8 lbm/1,000 gal, with 100-mesh sand at 1.6 lbm/1,000 gal.

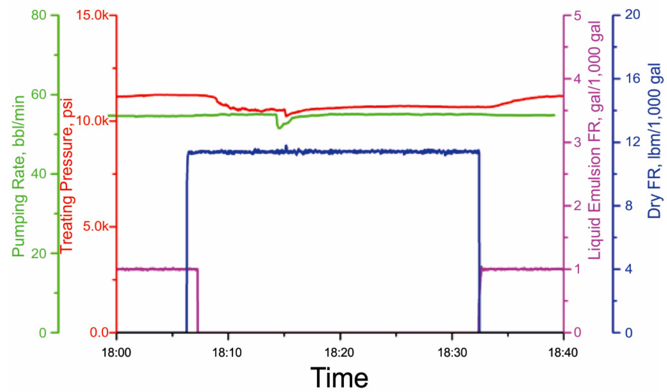

Fig. 9—Profile of the first test on the dry FR at 11.4 ppt, with 100-mesh sand at 1.6 lbm/1,000 gal.

The second field trail on the dry FR was performed in Cotton Valley. Because the design pumping rate and treating pressure were relatively lower, it was determined that the FR should be reduced to 0.5 gal/1,000 gal. Again, the liquid emulsion FR was used until the treating pressure stabilized. After switching to the dry FR at the same active polymer concentration, the treating pressure decreased from 4,402 to 4,306 psi; it decreased further to 4,261 psi after the first and second wellbore volume of the dry FR (**Fig. 10**). Next, the 0.25 gal/1,000 gal liquid emulsion FR was run to a stable treating pressure of 4,610 psi, with a proppant load of 0.75 lbm/1,000 gal 40/70-mesh Ottawa sand. As can be observed in **Fig. 11**, the treating pressure dropped to 4,336 psi after the first wellbore volume of the dry FR at 2.2 lbm/1,000 gal. It seemed that the treating pressure began to increase after an additional half wellbore volume. However, this was still lower than the level at which the 0.25 gal/1,000 gal liquid emulsion FR was running, even after the fourth wellbore volume (4,526 psi). This suggested that the dry FR would perform well, even at a low concentration of 2.2 lbm/1,000 gal, confirming the laboratory results and pilot scale tests.

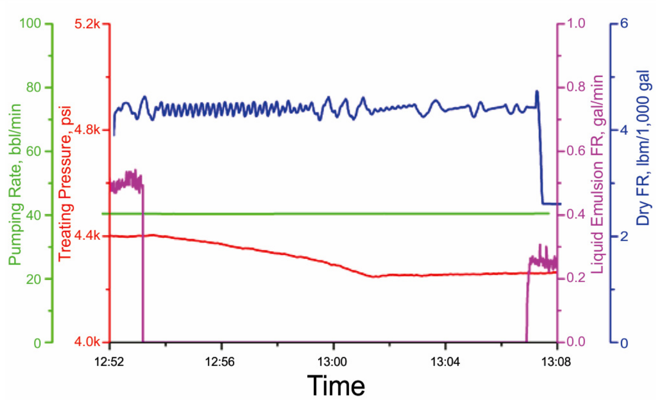

Fig. 10—Profile of the first test on the dry FR at 4.4 lbm/1,000 gal, with 40/70-mesh Ottawa sand at 0.5 lbm/1,000 gal.

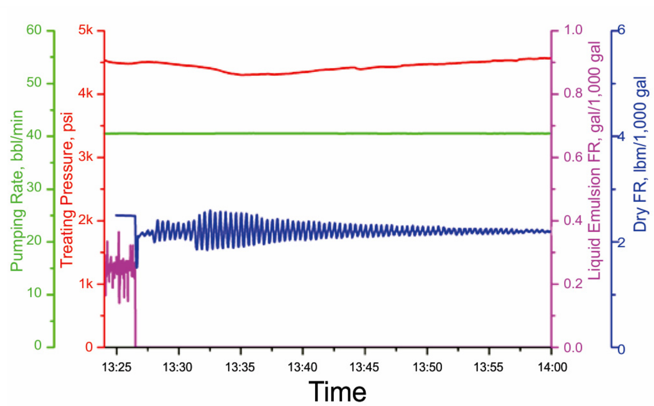

Fig. 11—Profile of the first test on the dry FR at 2.2 lbm/1,000 gal, with 40/70-mesh Ottawa sand at 0.75 lbm/1,000 gal.

Overall, 2,860 lbm of the dry FR was pumped during these two field trials. As a result, 325 gal of liquid emulsion FR were saved, which eliminated the use of a total of 488 lbm of hydrocarbons. If the dry FR was used to replace the liquid emulsion FR, more than 3,000 gal (or 20,089 lbm) of hydrocarbons could be eliminated during the water fracturing stimulation.

Operation Concerns

No accidents occurred during these field trials, and no interruption to the pumping schedule was experienced when the tests were performed. However, several challenges related to handling the dry FR on location should be considered. Because the dry FR is in the form of fine powder, it should be stored in dry conditions to prevent possible hydration when coming into contact with moisture. Thus, raining or foggy weather would make it difficult to use this dry FR on location. Additionally, efforts should be made to improve the efficiency during the dry FR feeding into the blender tub. This requires equipment design and or modification of the existing equipment.

Conclusions

A dry FR has been successfully developed and validated by laboratory tests, pilot scale tests, and field trials. No hydration issues were observed for this product as indicated by its instant friction reduction performance. It showed comparable to superior performance to the liquid emulsion FR during field trials and eliminated the use of 488 lbm of hydrocarbons downhole. It could potentially eliminate more than 3,000 gal of hydrocarbon for these two wells if the dry FR was used to replace the liquid emulsion FR throughout the entire treatment.

Acknowledgments

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Nomenclature

BHT = *Bottomhole temperature*
FR = *Friction reducer*

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