

Novel Low-Residue High Brine Fracturing Fluid

Loan K. Vo, Bradley Sparks, Christopher Parton, Janette Cortez, and Tanner Green, Halliburton

Copyright 2014, AADE

This paper was prepared for presentation at the 2014 AADE Fluids Technical Conference and Exhibition held at the Hilton Houston North Hotel, Houston, Texas, April 15-16, 2014. This conference was sponsored by the American Association of Drilling Engineers. The information presented in this paper does not reflect any position, claim or endorsement made or implied by the American Association of Drilling Engineers, their officers or members. Questions concerning the content of this paper should be directed to the individual(s) listed as author(s) of this work.

Abstract

A typical hydraulic fracturing treatment can consume, on average, 3 to 5 million gal of water (usually fresh water). This is particularly problematic for offshore jobs, where fresh water must be transported to the well site; whereas, seawater is readily available. Very few conventional polymers perform well in brine; however, even fewer perform well in hard brines, such as seawater, which typically includes high concentrations of divalent metal ions, such as magnesium and calcium. The presence of divalent metal ions in seawater inhibit the full hydration of the polymer, which results in a lower base gel viscosity and ultimately affects the final properties of the crosslinked fluid system. Several seawater-tolerant fracturing fluids are currently available, but none of these fluids meet the current requirements to reduce formation damage caused by a relatively high percentage ($\geq 5\%$) of insoluble residues in the polymer system.

This paper describes the development of a new fracturing fluid system, which is designed to be completely compatible with seawater and, virtually, residue-free upon breaking. This high-brine tolerant fracturing fluid allows easy control of gel hydration, as well as its effective crosslinking and breaking performance using conventional additives. Fracturing fluid designs are included to demonstrate the fluid system's versatility involving its rheological and fluid-loss properties. Results obtained from experimental testing of fracture conductivity, regained permeability, and polymer residue from various proppant packs indicate that this new fluid system provides excellent cleanup properties for the propped fractures to enhance and maintain well productivity.

This new fluid system provides improved logistical flexibility and cost management for hydraulic fracturing treatments offshore by broadening water specification requirements; additionally, it provides the expectation of improved post-fracturing production.

Introduction

The hydraulic fracturing process has been used commercially as a means of stimulating oil and gas production for more than 60 years. During the fracturing process, a viscous non-Newtonian fluid is applied to the formation with three major functions: (1) delivering pressures to create fracture network and geometry within the stimulated zone, (2) transporting proppant into the created fracture to maintain fracture conductivity, and (3) control of fluid leakoff into the

formation by forming a filter cake on the walls of the fracture. To accomplish this, a fracturing fluid is required to have appropriate viscosity and elasticity, while yielding low friction during pumping. A high performance fluid is one that not only can deliver the proppant into the fracture efficiently, but must also have the ability to clean up rapidly and effectively after the treatment is complete, leaving no damage to the formation and proppant pack. Many different types of fluids have been developed to provide these performance criteria.¹⁻⁴ With respect to aqueous-based fracturing fluids, typically polysaccharides or polysaccharide derivatives are polymers of choice as fracturing fluids for wells with bottomhole temperatures (BHTs) less than 300°F, while synthetic polymers are chosen for wells with higher BHTs.

Among the many different choices of fracturing fluid systems, guar-based fluids have historically been the fluid of choice because of their reliable and flexible chemistry, as well as their great incentive from the economical aspect. One of the most desirable characteristics of the guar-based fluid system is its ability to crosslink using borate crosslinkers, which uses the *cis*-diol functionality for crosslinking.^{1,5} Borate crosslinking chemistry is a reversible process, hence, lending the borate crosslinked fluid system the rehealability often preferred for fracturing. This rehealable characteristic of borate crosslinked guar-based fluids manifests well in its reliable rheological property, as well as the low sensitivity toward high shear conditions. However, the biggest drawback of the guar-based fluid system is the insoluble residue (protein and cellulose) present in the fluid after breaking. Guar-based fluids are known to contain up to 10% of this insoluble residue.⁶⁻⁸ These insoluble residues are recognized as being partially responsible for the loss of conductivity within the proppant pack. Efforts to reduce the concentration of insoluble residue in the guar gum have been investigated by means of improvements to manufacturing processes and chemical modifications. Despite the recent efforts, even the most commonly used guar derivative, carboxymethyl hydroxopropyl guar (CMHPG), still contains up to 5% insoluble residue.⁹⁻¹³

Conversely, the use of viscoelastic surfactant (VES) fracturing fluids has introduced an alternative viscosifying system for fracturing applications.¹⁴⁻¹⁸ The VES systems offer great elasticity for proppant transport and high-retained conductivity because it is a non-polymer system. However, these fluid systems suffer in terms of leakoff control and often

require supplemental fluid-loss control agents (e.g., CaCl_2 , silica flour, etc.) to control fluid loss. Additionally, the economic factor is another drawback of the VES system that cannot be ignored, where typical VES systems are more expensive than water based polymeric fluid systems.

The most current hydraulic fracturing operations require the transport of a large amount of fresh water to location for fracturing treatments. At the end of the job, the disposing activity, or the transport of flowback or produced water offshore, quickly increases the cost of the hydraulic fracturing jobs. In offshore operations, the ability to use readily available seawater to formulate a quality fracturing fluid on-the-fly has become highly desirable. For land operations, the demand for using produced water to build fracturing fluids has received great attention also. Attempts have been made to treat produced waters and reuse them in fracturing treatments with limited success, particularly in slickwater treatments and low-temperature crosslinked treatments.^{19,20} Different fluid systems have also been developed using seawater for offshore applications.²¹⁻²⁷ However, the water treatments usually either involve some preconditioning of the seawater, such as filtration or precipitation methods to remove different ions in the water or pH adjustments of the fluid to help the hydration of the polymers in seawater. Other operations involve the use of a combination of fresh water and seawater to make up the fluid. The current seawater-based polymer fluid systems involve borate crosslinked guar or its derivatives. Guar and its derivatives have been known to offer reliable fracturing fluids, but suffer from the poor cleanup because of insoluble residue left behind in the proppant pack or formation after breaking.

This paper presents a new fracturing fluid system developed using 100% seawater that offers the desired proppant transport/suspension and fluid-loss characteristics of a polymer-based fluid system, as well as the cleanliness of a VES fluid. New crosslinker and breaker technologies allow for precise viscosity control, which can be controlled as a function of reservoir conditions and operational requirements, to help ensure proppant placement. Additionally, the fluid cleans up efficiently as a result of the less than 1% insoluble residue of the polymer, which should result in enhanced well production.

Discussion

In an offshore environment, ample, cost-effective seawater is readily available. The concept of using seawater as a base fluid for fracturing operations has been attempted before. However, seawater contains dissolved inorganic salts, such as calcium and magnesium, which can cause precipitation or adversely affect the hydration and viscosity of many polymer-based fluids. Ultimately, fluid technology often does not transfer directly from fresh water to seawater. Current polymer-based fluids still use fresh water to prepare an aqueous gel concentrate while onshore, which is subsequently diluted with seawater while offshore to reach the final polymer concentration.

This new clean fluid developed demonstrates exceptional rheological performance in 100% seawater, with no preconditioning or pH adjustment of the seawater. The gel

concentrate of the fluid can easily be prepared using seawater at the dock, which can be diluted using seawater offshore. Eliminating the requirement for fresh water provides a great advantage from both a logistic and an economic perspective. The fluid hydrates quickly in seawater with no gel balls ('fisheyes') or precipitation issues. This fluid also exhibits stability in high density brine conditions, when prepared with 12.5-lbm/gal NaBr, which allows the opportunity for deep water fracturing applications.

Whether a polymer-based or VES system, having controllable rheological properties is fundamental in a well-designed fracturing fluid system. A good fluid system allows operation engineers the ability to easily adjust the formulation to meet operational and reservoir requirements. This fluid has shown stable viscosity up to 250°F in seawater. The breakers designed for the fluid system offer precise viscosity control, where different break times can be attained with the adjustment of breaker concentrations.

Excessive fluid loss into the formation during fracturing job poses serious problems, including screenouts, sandouts, and gelouts, which can lead to termination of the fracturing job. In deep-well, high-permeability completions, effective control of loss of expensive brine completion fluid is a major challenge. The invasion of the fluid into the formation also increases the chance of formation being damaged, especially when the fluid is not efficiently cleaned out of the formation because of incomplete breaking or the presence of insoluble residue. Formation damage testing results conducted in unconsolidated sandpack regained permeability on the fluid have demonstrated the fluid leaving minimal formation damage with 70% and higher regained permeability. More importantly, this seawater-based fluid system also exhibits efficient fluid loss control properties without the addition of auxiliary fluid loss additives. The fluid yields C_w and Spurt values comparable to current high performance polymer fluids (**Table 1**).

Table 1—Fluid Loss Values

	Temperature	Spurt (gal/ft ²)	C_w (ft/min ^{0.5})
The new seawater-based Fluid	180 °F	0.0215	0.00256
HPG	180 °F	0.012	0.0038
Guar	180 °F	0.0106	0.00359
CMHPG	180 °F	0.0228	0.0035

In addition to tailoring the rheological properties in seawater, this seawater-based fluid has proven to suspend and transport proppant under dynamic and static conditions. Upon delivering proppant to the formation, the ability to break cleanly and rapidly to allow easy flowback, as well as leaving minimal conductivity reduction on the proppant pack, are essentially the ultimate goals of any fracturing fluid. This fluid system has demonstrated the ability to clean up with no insoluble residue remaining in the proppant pack. As a result, maximum regained permeability in the proppant pack is

achieved, which is critical to obtaining maximum production. Laboratory results show greater than 70% in both regained permeability and retained conductivity, confirming the cleanliness of this fluid. This is considered one of the most desirable characteristics of a fracturing fluid.

The effect of shear on a fluid's proppant carrying characteristic is always a point of discussion. Because of the lack of the reheelability characteristic that exists in a metal-crosslinked fluid, the challenge of this fluid system lies in the balance of the crosslinked system. The crosslinked fluid system must be robust enough to sustain high temperature and high shear effect to hold together the crosslinked network to suspend proppant. Conversely, the crosslinked fluid system also must be readily and efficiently uncrosslinked and broken to yield an efficient cleanup with minimal formation and proppant pack conductivity damage. This clean fluid system uses the combination of instant and delayed crosslinking mechanisms to overcome the shear sensitivity issue while optimizing the cleanliness property of the fluid.

Experimental Procedures and Results

All tests were conducted using either American Society for Testing and Materials (ASTM) synthetic seawater or real Gulf of Mexico (GOM) seawater with the addition of 3% KCl by weight as a clay control agent. Results were consistent in the ASTM synthetic seawater versus the real GOM seawater.

Synthetic seawater was prepared following the ASTM 1141-98 composition. **Tables 2 and 3** summarize, respectively, the compositions of both ASTM seawater and GOM seawater.

Table 2—ASTM Seawater Composition

Constituent	Quantity
Deionized water	1 L
NaCl	584.9 g
MgCl ₂ ·6H ₂ O	264.6 g
Na ₂ SO ₄	97.5 g
CaCl ₂	27.65 g
KCl	16.45 g
NaHCO ₃	4.77 g
KBr	2.38 g
H ₃ BO ₃	0.71 g
SrCl ₂ ·6H ₂ O	0.95 g
NaF	0.07 g
Specific gravity	1.025

Table 3—GOM Seawater Composition

Constituent	Quantity (mg/L)
Water	1 L
Al	0.27 mg
B	3.86 mg
Ba	0.03 mg
Ca	298 mg
Fe	0.22 mg
K	286 mg
Mg	971 mg
Na	9,494 mg
Sr	5.53 mg
Chloride	20,569 mg
Carbonate	20.7 mg
Bicarbonate	115 mg
Sulfate	1,600 mg
Specific gravity	1.021
Total dissolved solid (TDS)	33,068

Rheological Properties

Hydration Test

During a hydration study, polymer powder was added to 100-mL of seawater (fortified with 3 wt% KCl) stirring in a Waring® blender (medium rate that was enough to generate a slight vortex) to make up the desired concentration. The mixture was allowed to mix for 30 sec and quickly transferred into a 250-mL plastic cup. The cup transferred to a Fann 35 viscometer affixed with a R1/B1 rotor/bob geometry at 511 sec⁻¹ (300 rpm) for 60 min at room temperature. **Fig. 1** illustrates the polymer achieves full hydration in seawater within 5 min.

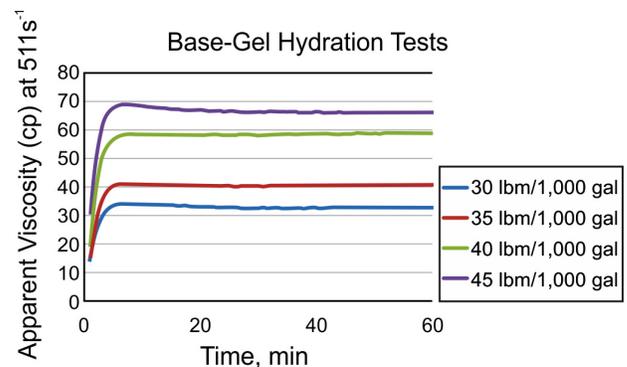


Fig. 1—Hydration of the polymer in GOM seawater.

Rheology Test

A Chandler 5550 viscometer was used to obtain rheology data at various temperatures. All tests were conducted at a 40-sec⁻¹ shear rate, using a R1/B5X rotor/bob geometry with a temperature ramping schedule from ambient temperature (~75 °F) to testing temperature within 5 min. During an example procedure, polymer powder was added to 250-mL seawater (fortified with 3 wt% KCl) stirring in a blender (medium rate that was enough to generate a slight vortex) to yield a 40-lbm/1000 gal concentration. The powder was dispersed into seawater and allowed to hydrate for 30 min. After the polymer fully hydrated, a 50-mL aliquot of the hydrated gel was transferred into a small 100-mL Waring blender, and the appropriate crosslinkers and breakers were added. The mixture was then transferred into a the Chandler 5550 cup for the rheological study.

Table 4 summarizes the typical formulations of the fluid at selected temperatures. Figs. 2 through 5 provide the representative viscosity profiles of the crosslinked fluids and their corresponding break profiles at various temperatures.

Table 4—Fluid Formula at Different Temperatures

Additives	Concentration (per 1000 gal)			
	120°F	180°F	200°F	225°F
Base fluid	SW	SW	SW	50:50 SW: 12.75 lbm/gal NaBr
Polymer (lbm)	35	40	45	45
Surfactant (gal)	1	1	1	1
pH control agent (gal)	—	0.25	0.25	0.25
Instant crosslinker (gal)	0.75	0.325	0.325	0.325
Delayed crosslinker (gal)	—	0.325	0.325	0.325
Homogeneous breaker (gal)	0.1	0.5	0.5	—
Delayed breaker (lbm)	10	5	5	10
High-temperature gel stabilizer (gal)	—	—	—	5

SW = Seawater

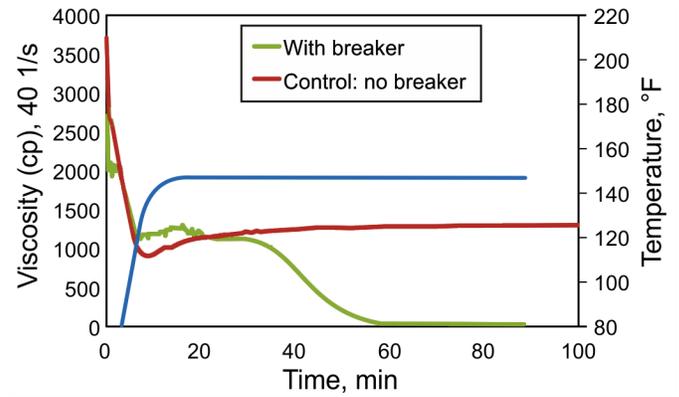


Fig. 2—Viscosity profiles in seawater at 150°F.

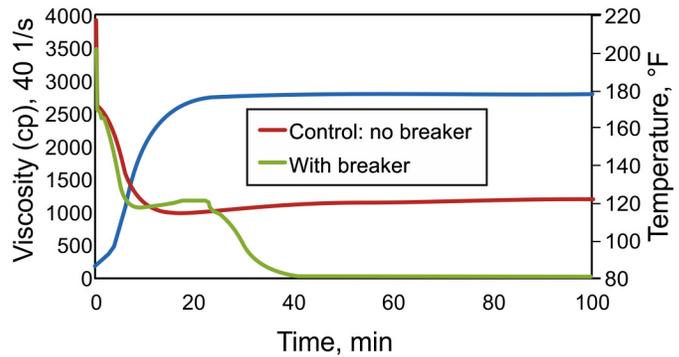


Fig. 3—Viscosity profiles in seawater at 180°F.

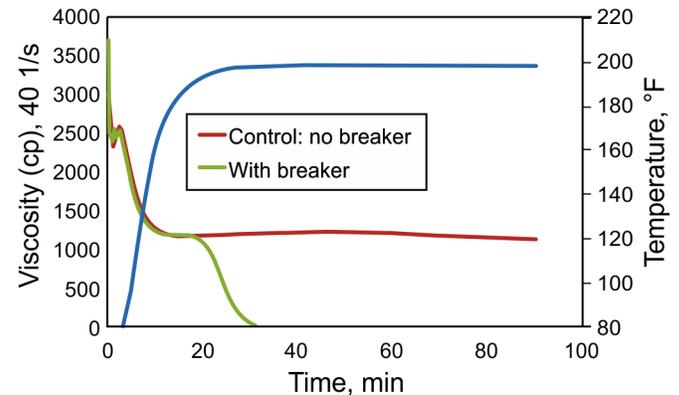


Fig. 4—Viscosity profiles in seawater at 200°F.

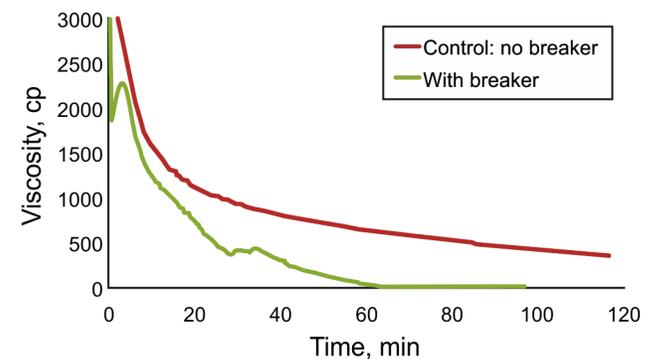


Fig. 5—Viscosity profiles in heavy weighted brine at 225°F.

The fluid rheological performance (i.e., viscosity and break times) can be tuned to meet reservoir and operational requirements by altering either crosslinker or breaker concentrations. **Fig. 6** illustrates that breaker control can provide reliable viscosity break times.

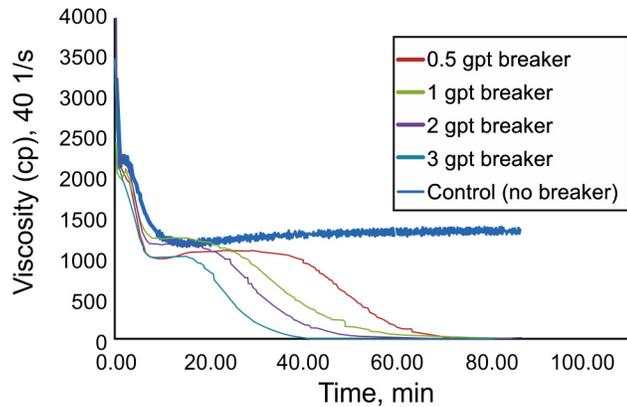


Fig. 6—Viscosity profiles of fluid with various breaker concentrations at 150°F.

Static Proppant Test

Base gel fluid was prepared in seawater at the required concentration, and 20/40-mesh bauxite proppant was added at a 6-lbm/gal concentration into the linear gel while stirring using a Waring blender. To this mixture, a designed volume of crosslinker was added to crosslink the fluid system. A 100-mL aliquot of crosslinked gel containing proppant was placed in a 125-mL graduated jar. The sample was subsequently placed into a heated water bath at 200°F and observed for proppant settling. For comparative purposes, a borate crosslinked guar fluid system was also prepared using the same procedure and placed into the water bath at the same time. **Fig. 7** illustrates a picture of the proppant suspension (or settling) of the two fluids in progress after 3 min, 3 hr, and 6 hr at 200°F.



Fig. 7—Static proppant suspension at 200°F after 3 min (left), 3 hr (middle), and 6 hr (right). The jar on the left is a guar-based fluid. The jar on the right is the newly developed clean seawater-based fluid presented in this paper.

Fluid-Loss Tests

Sample Preparation

Core samples were cut out of Ohio sandstone and shaped to fit two modified American Petroleum Institute (API) linear flow cells. Two cells were used to control naturally occurring variations. Each core face had a surface of 10 in.² for fluid loss

and a contact area for the proppant. Two core wafers were placed into the test cell with a 0.3-in. preset gap, which provided a shear rate of approximately 50 sec⁻¹ at a pumping rate of 0.34 gal/min. This gap allowed for dynamic fluid loss before proppant placement.

Dynamic Fluid-Loss Test

The test fluids were prepared and quality-checked to help ensure appropriate pH and crosslink characteristics. The fluid was pumped at 0.34 gal/min (1,800 sec⁻¹) through 0.25-in. outside diameter (OD) stainless-steel tubing. This rate provided the preconditioning and shear history equivalent to fluid moving through 2.875-in. tubing at 16 bbl/min. Next, the lower shear rate (50 sec⁻¹) of fluid flow in a fracture was simulated. From this simulation, fluid was pumped into a 0.75-in. OD stainless-steel tubing section that was immersed in a heating bath that had a temperature representative of fracture conditions. The fluid then passed through the heated test cells, where the dynamic fluid loss occurred. A 1,000-psi pressure differential allowed for fluid loss across the core wafers. The total test time was 90 min.

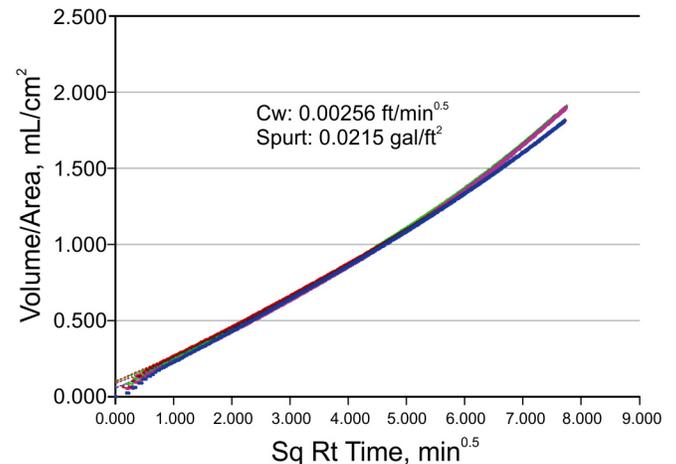


Fig. 8—Dynamic fluid-loss study of the clean fluid, conducted at 180°F. The inset shows a picture of the filter cake built from this clean fluid.

Fracture Conductivity Test

Following the fluid-loss test, the two API cells were opened to measure the filter cake formed on the Ohio sandstone. Then, 20/40-mesh proppant was placed into the test cell between the two wafers. The fluid-loss end was then replaced with conductivity ends, which were used to flow brine solution through the proppant pack. Test cells were then loaded into a hydraulic press, where closure stress could be applied, and the reservoir temperature could be controlled. Differential pressure was measured as a 2% KCl brine solution was flowed through the cells to determine conductivity. Two additional control cells were prepared with only a proppant pack in between the two wafers. Conductivity measurements were taken several times throughout a period of at least 48 hr. Once the fluid differential pressure stabilized, the stress increased on all four cells, and the process was repeated until the full stress

spectrum was obtained. Closure stresses were increased from 2,000 psi to 4,000 psi, then to 6000 psi, and conductivity measurements were obtained at each closure stress. **Fig. 9** summarizes the results of the studies at 2,000 psi closure stress. Experiments were conducted on fluids from 120 to 250°F; all showed retained conductivities of equal or higher than 70%, clearly confirming the residue-free characteristic of the polymer causing minimal impact on the proppant pack conductivity.

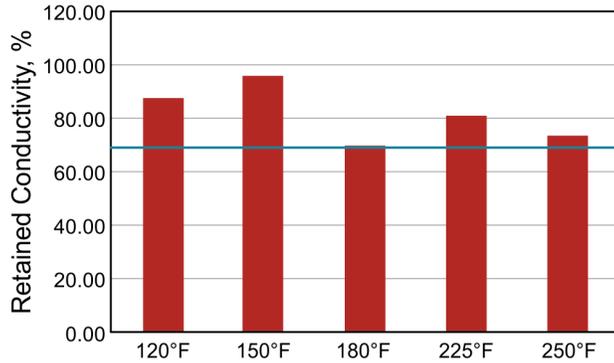


Fig. 9—Retained conductivity data of the clean fluid at various temperatures.

Core Regained Permeability Test

During this test, appropriate breakers were added to the fluid system prepared in seawater. The fluid was then crosslinked with designed crosslinkers at the designated test temperature. The entire fluid system was then used to treat Berea (low permeability) or Castlegate (high permeability) cores (1-in. inside diameter (ID) and 2.5-in. length) at permeabilities ranging from 50 to 750 mD. Pressure transducers were installed at the inlet and outlet of the flow-cell assembly as a means of measuring the pressure drop across the sandstone core during fluid injection. The confining pressure was set to 500 psi. The backpressure regulator was set to 200 psi. The Berea or Castlegate core was first saturated by flowing 7% KCl brine at a 3-cm³/min flow rate for low permeability cores and a 10-cm³/min flow rate on higher permeability cores until the differential pressure equalized. The cell assembly containing the core was then heated up to the test temperature. This temperature was maintained during the entire flow period of the experiment. At a steady flow rate of 3 or 10 cm³/min, the initial permeability of the core was determined. The core was then treated with five pore volumes of the treatment fluid until the core interface reached a 1,000 psi differential pressure. At which point, the fluid was diverted from the core interface. The 1,000 psi diversion point represents the treating pressure in fluid loss. An assumption is that once the filter cake forms, the formation will no longer be damaged. The volume of fluid treated through the core was confirmed by the amount of fluid exiting the cores. The treated core was shut in for 48 hr at temperature. Then, in reverse flow, or production direction, 7% KCl was injected at a 3- or 10-cm³/min flow rate to determine the final permeability, or regained permeability, of the core upon fluid treatment. The

experiments conducted all showed regained permeabilities equal to or higher than 70% (**Fig. 10**), indicating minimal formation damage caused by the fluid.

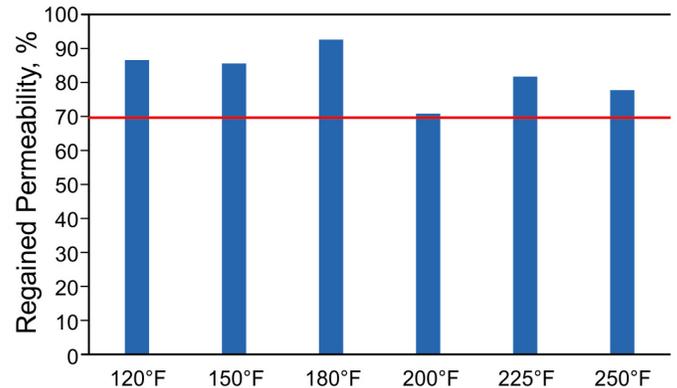


Fig. 10—Core regained permeability data of the clean fluid at various temperatures.

Proppant Pack Damage Test

Confirming the results of the conductivity test, this laboratory test was designed to visually compare the cleanup properties of this seawater fluid versus guar-based fluid. During this test, both gels, at their typical use formulations, were crosslinked and broken for 24 hr at 180 °F. Then, five pore volumes of the broken fluids were passed through a proppant pack of 20/40-mesh proppant to simulate flowback. A video of the flow of broken fluid through the proppant pack was recorded. **Fig. 11** shows a snapshot of the flowing process, clearly indicating that the seawater fluid system leaves no visible insoluble residue upon breaking, keeping the pore space in the proppant pack clear and maintaining conductivity. Conversely, the insoluble residue in a broken guar fluid quickly fills the pore space in the proppant pack, dramatically impairing its flow and conductivity.

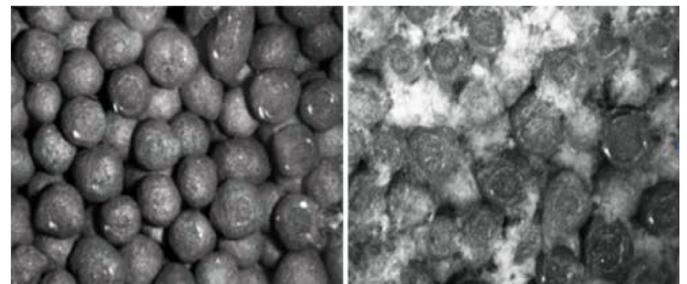


Fig. 11—Proppant pack treated with broken clean fluid (left) and broken guar fluid (right).

High-Shear Loop Test

Similar to any polymer-based fracturing fluid, the effect of shear on the fluid's properties (i.e., viscosity and proppant suspension/transport) is of great importance. In an effort to address such concerns, the formulations of this fluid were subjected to several shearing events.

The testing apparatus includes as follows:

- 1/32-in. ID, 10-ft length tubing placed at room temperature. At a flow rate of 2.5 cm³/min, this tubing yields a ~1,000 sec⁻¹ shear rate for 30 sec.
- 1/16-in. ID, 30 ft long tubing submerged in a water bath that can be brought to desired temperatures with a temperature limitation of 200°F. At a flow rate of 2.5 cm³/min, this tubing yields a 106 sec⁻¹ shear rate for 8 min.

The test apparatus consisted of three major components: dual piston constant flow pump, 250-mL accumulator, and a two-phase shear loop. The piston pump was set to pump at 2.5 cm³/min, and tap water was pumped into the bottom of the accumulator. The piston pump flowed at 2.5 cm³/min regardless of the pressure generated, up to 3,000 psi. The accumulator's piston then injected the fluid through the shear loops tubing.

Fig. 12 illustrates a diagram of the bench-top shear loop setup.

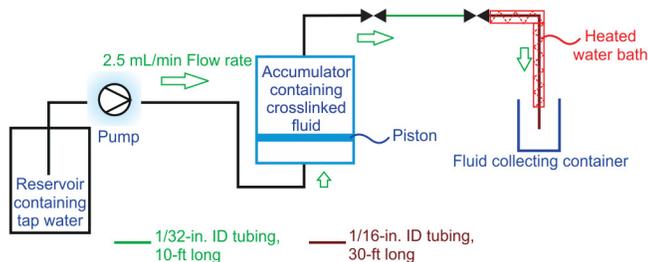


Fig. 12—Diagram of the bench-top shear loop setup.

During this experiment, the crosslinked fluid was subjected to a 1,000-sec⁻¹ shear rate at room temperature for 30 sec⁻¹ (simulating high shear rate at the crossover tool), then subjected to 100 sec⁻¹ (simulating low shear rate in the fracture) at a designated temperature for 8 min. This is similar to the shearing that a fluid experienced during the fluid-loss conductivity test. Fig. 13 illustrates a photograph of a fluid that had been exposed to 1,000 sec⁻¹ and followed by 100 sec⁻¹ shear rate at 180 °F for 8 min. After the fluid had been subjected to a high shear condition, 20/40-mesh Bauxite proppant was added at 2 lbm/gal concentration to the fluid. The sheared fluid demonstrated the capability to suspend proppant with no apparent reduction to performance.



Fig. 13—Proppant-suspended fluid after high shear and temperature history.

Conclusions

Based on the results of this study, the following conclusions were reached:

- A low residue polymer that rapidly hydrates in 100% seawater was developed without a need for the water to be preconditioned.
- The ability to hydrate in 100% seawater relieves logistical issues involving the transportation of fresh water to and from the well site.
- The fluid can be reliably and competently crosslinked in 100% seawater.
- A stable crosslinked fluid was also achieved in weighted NaBr brine.
- The developed 100 % seawater-based fluid has tunable viscosity, an essential characteristic for reliable proppant transport and suspension.
- The low residue polymer, in combination with the breaker design, resulted in both high retained conductivity and regained permeability.
- The fluid exhibits efficient fluid loss properties with C_w and Spurt values comparable with guar fluid systems.
- Model shear history tests indicate that the polymer and crosslinker design result in a fluid that is expected to be resilient to the high shear conditions exposed to during pumping.

Acknowledgments

The authors thank Halliburton management for permission to publish this paper. The authors also extend a special thanks to Dustin Durbin, Mike Gideon, and Jeff Fleming for their contributions to this work.

References

1. Harris, P.C. 1993. Chemistry and Rheology of Borate Crosslinked Fluids at Temperature up to 300°F. *J. Petrol. Tech.*, **45** (3): 264–269. SPE-24339-PA.
2. Harris, P.C., Harms, W.M., and Norman, L.R. 1989. Study of Continuously Mixed Crosslinked Fracturing Fluids With a Recirculating Flow-Loop Viscometer. *SPE Prod. Engr.* **4** (4): 430–434. SPE-17044-PA.
3. Zhuang, Z. and Zhangshichneg, Z. 2007. Research and Application of Fracturing Fluid of High Temperature and Low Concentration. *Oilfield Chemistry, J.* **24** (2): 120–123.
4. Powell, R.J., McCabe, M.A., Slabaugh, B.F., Terracina, J.M., Yaritz, J.G., and Ferrer, D. 1999. Applications of a New, Efficient, Hydraulic Fracturing Fluid System. *SPE*

- Prod. & Facilities*. **14** (2): 131–138. SPE-56204-PA.
5. Harris, P.C. and Heath, S.J. 1997. Rheological Properties of Low Gel-Loading Borate Frac Gels. Paper SPE 38621 presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, 5–8 October.
 6. Baker, W.W and Whistler, R.L. 1975. *Carbohydr. Res.* **45**, 237.
 7. Courtois, J. E. and Let Dizet, P. 1966. *Carbohydr. Res.* **3**, 141.
 8. Dass, P.J.H., Schols, H.A., and de Jongh, H.H.J. 2000. On the Galatosyl Distribution of Commercial Galactomannans, *Carbohydr. Res.* **329**, 609–619.
 9. Almond, S.W., Bland, W.E., and Ripley, H.E. 1984. The Effect of Break Mechanisms on Gelling Agent Residue and Flow Impairment in 20/40 Mesh Sand. PETSOC-84-35-30 presented at the Annual Technical Meeting, Calgary, Alberta, 10–13 June.
 10. Tomas, R. 1989. The Impact of Fracturing Fluids on Conductivity and Performance in Low-Temperature Wells. SPE 18862 presented at the SPE Production Operations Symposium.
 11. Penny, G. 1988. STIM-LAB, Inc. Consortium: Final Report on the Investigation of the Effects of Fracturing Fluids upon the Conductivity of Proppants.
 12. Nimerick, K.H. Borate Crosslinked Fracturing Fluid and Method. U.S. Patent 5,681,796.
 13. Norman, W.D., Jasinski, R.J, and Nelson, E.B. Hydraulic Fracturing Process and Compositions. U.S. Patent 5,551,516.
 14. Huang, T. and Crews, J. 2007. Fluid-Loss Control Improves Performance of Viscoelastic Surfactant Fluids. *SPE Prod. & Operations*. **24** (1): 60–65. SPE-106227-PA.
 15. Samuel, M., Polson, D., Graham, D., Kordziel, W., Waite, T., Waters, G., Vinod, P.S., Fu, D., Downey, R. 2000. Viscoelastic Surfactant Fracturing Fluids: Applications in Low Permeability Reservoirs. Paper SPE 60322 presented at the SPE Rocky Mountain Regional/Low-Permeability Reservoirs Symposium and Exhibition, Denver, Colorado, 12–15 March.
 16. Huang, T., Crews, J. 2008. Nanotechnology Applications in Viscoelastic Surfactant Stimulation Fluids. Paper SPE 107728 European Formation Damage Conference, Scheveningen, The Netherlands, 30 May–1 June.
 17. Chen, Y., Pope, T.L., Lee, J.C. 2005. Novel CO₂-Emulsified Viscoelastic Surfactant Fracturing Fluid System. Paper SPE 94603 presented at the SPE European Formation Damage Conference, Scheveningen, The Netherlands, 25–27 May.
 18. Heitmann, N., Pitoni, E., Devia, F., Simone, R. 2001. Polymer-free Fluid Technology Optimizes Seawater Fracturing. Paper OMC-2001-047 presented at the Offshore Mediterranean Conference and Exhibition, Ravenna, Italy, 28–30 March.
 19. Li, L., Eliseeva, K.E., Eliseev, V., Bustos, O.A., England, K.W., Howard, P.R., Boney, C.L., Parris, M.D., and Ali, S.A. 2009. Well Treatment Fluids Prepared with Oilfield Produced Water. Paper SPE 124212 presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, 4–7 October.
 20. Gupta, D.V, Satya, V., Carman, P.S., Venugopal, R. 2012. A Stable Fracturing Fluid for Produced Water Applications. Paper SPE 159837 presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, 8–10 October.
 21. Hoang, L. and Wood, R. 1992. New Frac Fluid Enhances Options for Offshore Wells. *Ocean Industry*.
 22. Thesing, A. 1993. Sea Water Based Borate Crosslinked Fluids for Use in Fracturing Application up to 300 °F. Paper presented at the 6th Clausthaler Symposium, Clausthal, Germany, February..
 23. Powell, R.J., McCabe, M.A., Slabaugh, B.F., Terracina, J.M, and McPike, T. 1998. Gulf of Mexico Frac-and-Pack Treatments Using a New Fracturing Fluid System. Paper SPE 39897 presented at the International Petroleum Conference and Exhibition of Mexico, Villahermosa, Mexico, 3–5 March.
 24. Harris, P.C. and van Batenburg, D. 1999. A Comparison of Freshwater- and Seawater-Based Borate-Crosslinked Fracturing Fluids.. Paper SPE 50777 presented at the SPE International Symposium on Oilfield Chemistry, Houston, Texas, USA, 16–19 February.
 25. Bagal, J., Gurmen, M.N., Holicek, R.A., Gadiyar, B.R., and Fredd, C.N. 2006. Engineered Application of a Weighted Fracturing Fluid in Deep Water. Paper SPE 98348 presented at the SPE International Symposium and Exhibition on Formation Damage Control, Lafayette, Louisiana, USA, 15–17 February.
 26. Rivas, L.F., Navaira, G., Bourgeois, B.C., Waltman, R.B., Lord, P.D., and Goosen, T.L.. 2008. Development and Use of High-Density Fracturing Fluid in Deepwater Gulf of Mexico Frac and Packs.. Paper SPE 116007 presented at the SPE Annual Technical Conference and Exhibition, Denver, Colorado, USA, 21–24 September..
 27. Qiu, X., Martch, E.W., Morgenthaler, L.N., Adams, J., and Vu, H.S. 2009. Design Criteria and Application of High-Density Brine-Based Fracturing Fluid for Deepwater Frac Packs.. Paper SPE 124704 presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, 4–7 October.