OTC-30267-MS

A Systematic Approach to Deploy a Novel Nondamaging Fracturing Fluid to Field

Prasad Karadkar and Mohammed Alabdrabalnabi, Saudi Aramco; Feng Liang, Aramco Services Company: Aramco Research Center–Houston; Adrian Buenrostro, Saudi Aramco

This paper was prepared for presentation at the Offshore Technology Conference Asia originally scheduled to be held in Kuala Lumpur, Malaysia, 17 - 19 August 2020. Due to COVID-19 the physical event was postponed until 2 – 6 November 2020 and was changed to a virtual event. The official proceedings were published online on 27 October 2020.

Abstract

Guar gum and its derivatives based fracturing fluids are most commonly used in hydraulic fracturing. For high temperature wells, guar-based fracturing fluids need to be formulated with higher polymer loading and at a high pH that leaves insoluble residue and tendency to form scales with divalent ions. In this paper, a systematic approach to field deploy a novel low-polymer loading, nondamaging acrylamide basedfracturing fluid system is presented.

Thermally stable acrylamide-based polymer with reduced polymer loading of 30-40% less than guar-based fracturing fluid was considered to minimize formation damage concerns. For successful field deployment, a novel nondamaging fracturing fluid was evaluated in following sequence: chemical management and quality control, optimization of fracturing fluid formulations with field water, field mixing procedure, onsite QA/QC, friction analysis, leakoff analysis, data frac analysis and execution of main fracturing treatment. In both scenarios, batch mixing and on-the-fly mixing of linear gel were evaluated. The friction of crosslinked fluid was analyzed by using bottomhole gauge and fluid efficiency was evaluated during data frac analysis.

This paper presents rheological studies at bottomhole static temperature (BHST) and cool down temperatures of selected well candidates that demonstrate superior thermal stability of this novel fracturing fluid. With polymer loading of 25 lb/1000 gal, the fluid viscosity stayed above 300 cP at 100 1/s shear rate for 2 hours at 290°F. The fracturing fluid formulations were optimized using both live and encapsulated breakers with high pressure and high temperature (HPHT) rheometer. Due to the fast hydration of the base polymer, the linear gel was mixed both in batches and on-the-flying during the main fracturing treatment. Slightly higher friction at higher pumping rate was observed by the down hole gauge during data frac for this novel fracturing fluid as compared to guar-based fracturing fluid. The main fracturing treatment was successfully executed with 45-50 barrels per minute (bbl/min) pumping rate with increased proppant concentration up to 5 pounds per gallon (ppa) using 30/50 high strength proppant (HSP) proppant.

The fracturing fluid system based on the novel acrylamide copolymer offers advantages over guar-based fracturing fluid such as low polymer loading, excellent high temperature stability and less formation

damage. This paper presents a systematic approach and lesson learnt during novel fracturing fluid deployment.

Introduction

Hydraulic fracturing is commonly used in stimulating low-permeability or damaged reservoirs. In hydraulic fracturing operations, a fracturing fluid is pumped to crack open the formation. Linear fluid is typically pumped first in pad or pre-pad treatment to initiate fractures and create the fracture geometry. Proppant-laden fluid is later injected to increase the length and width of fractures further into formations. At the end of a fracturing job, the pumping pressure drops. As the result, the fractures close onto the proppant, which are used to keep the fractures open during oil and gas production. The created fracture networks will facilitate the efficient flowing and production of hydrocarbons from reservoirs.

Most commonly used hydraulic fracturing fluids are water-based fluids, such as slickwater, linear fluids, crosslinked fluids, foamed fluids, and viscoelastic surfactant (VES) fluids (Fink 2003; Al-Muntasheri 2014; Li et al. 2016; Wang et al. 2015; Samuel et al. 1997; Kefi et al. 2004). For brittle shale formation, a slickwater fluid system is typically used to create a complex fracture network (Chong et al. 2010). Slickwater fluids comprises mostly of water, with low dosages of additives including friction reducer, biocide, surfactant, scale inhibitor, etc. Acrylamide-based polymer or co-polymers are the typical friction reducers. In recent years, the slickwater fracturing has become a standard treating technique in Barnett, Haynesville, or Marcellus shales (Ketter et al. 2006; King 2010). Slickwater treatments are usually pumped at high pumping rate (typically more than 60 bbl/min), carrying low concentrations of proppant, often at small proppant mesh sizes such as 100 mesh (Wang et al. 2015), and generating narrow fractures (Palisch et al. 2008; Liang et al. 2016a). At such high pumping rate, high molecular weight friction reducer is used to reduce the friction pressure and related pumping power by as much as about 70-80%. Linear fluids are uncrosslinked solutions of polymers such as guar, guar derivatives, cellulose, cellulose derivatives, or synthetic polymers such as acrylamide-based polymers and copolymers (Weaver et al. 2002). Linear fluid viscosity typically has higher viscosity than slickwater; thereby showing much better proppant transporting capability.

For ductile rock/shale, crosslinked fluids are typically used to create the conventional bi-wing fractures. The most commonly used crosslinked fracturing fluids are guar or guar-based derivatives including carboxymethyl hydroxypropyl guar (CMHPG), carboxymethyl guar (CMG), or hydroxypropyl guar (HPG). As well depth increases, the temperature and formation pressure become more severe and extend into the high-temperature high pressure (HPHT) range. Although the crosslinked guar or derivatized guar fluids can work at temperatures up to about 350°F when formulated with high polymer loading and high fluid pH, these types of fluids can damage proppant packs and formations due to the insoluble residue in guar-based polymers. Using high fluid pH to achieve high-temperature fluid stability can promote the formation of undesirable divalent ion scales in the high pH environment. Various synthetic acrylamide-based fluids have been developed and reported as cost-effective alternatives. Early studies include high molecular weight acrylamide-acrylate copolymer crosslinking with metal crosslinkers such as chromium (Rhudy and Knight 1976) and titanium or zirconium compounds (Williams et al. 1991), and acrylamide-methacrylate copolymers systems crosslinking with Cr^{3+} (Golinkin 1979). To improve the thermal stability of the synthetic acrylamide-based polymer at high temperature, 2-acylamdio-2-methylpropanesulfonic acid (AMPS) monomer was introduced into the polymer system. Funkhouser and Norman (2003, 2006) and Funkhouser et al. 2010 have reported a terpolymer of AMPS, acrylamide (AM) and acrylic acid or its salts. This system have been proved to work at temperatures between 350 and 400°F. These terpolymers have been used in very high concentrations as high as 86 pounds per thousand gallons (pptg). Gupta and Carman (2011) reported a high temperature fluid on using a terpolymer of acrylamide, AMPS and vinyl phosphonate crosslinking with zirconium based crosslinker. This system can be used at temperatures up to

450°F. Gaillard et al. (2013) have reported on using acrylamide-based associative polymers crosslinking with zirconium as the fracturing fluid. The anionic polymers investigated were acrylamide-based ter- and tetrapolymers prepared from monomers such as sodium acrylate, sodium acrylamido-tertiary-butyl sulfonate (ATBS) and a monomer with hydrophobic groups. Liang et al. (2016b, 2017a) reported a series of the synthetic acrylamide copolymers-based high-temperature fracturing fluids, crosslinked either with the nano-sized particulate crosslinker, or crosslinked with the nanomaterials-enhanced zirconium crosslinkers. In some cases, however, the acrylamide-based polymers were used at elevated dosages to achieve the high-temperature stability, for example, close to 90 pounds per thousand gallons (pptg) (Funkhouser et al. 2010). Large doses of acrylamide-based polymers and copolymers may still cause formation and proppant pack damages due to reasons like the incomplete breaking of the polymers at high concentrations.

Recently, a high-temperature, low polymer loading, novel acrylamide copolymer-based crosslinked fracturing fluid system was developed for application temperatures ranges from 280-450°F (Liang et al. 2017b). The fluid system has demonstrated the robust stability at elevated temperatures while hardly causing any damages in core flow and proppant pack conductivity under laboratory testing conditions. In this paper, further development work is published in efforts to deploy this fluid technology in the field for real job execution. For successful field deployment, a novel nondamaging fracturing fluid (NDFF) was evaluated in following sequence: chemical management, pre-job lab testing, field mixing scenarios, onsite QAQC, data frac analysis, friction analysis and finally main frac to fully validate NDFF capacity for proppant fracturing execuation. A total of four field trials were successfully performed using NDFF, in this paper one field case study is presented to show journey from laboratory investigations to field deployment.

Pre-Job Laboratory Testing

The NDFF was optimized before job to meet fluid stability criteria for selected well candidate. Water sample from designated water well and chemicals sample from respective batches were collected for pre-job lab testing. Water analysis was performed to check compatibility of water with frac fluid and potential risk of scale formation when mixed with formation water. The NDFF fluids were evaluated with different tests such as hydration test, vortex closure test, crosslink/lip time tests and rheology tests at HPHT conditions.

Frac fluid formulation

The NDFF formulation is shown in Table 1. It contains variety of different additives that are commonly used in typical frac fluid. Liquid gel concentrate (LGC) was produced using 2.5 lb/gal thermally stable acrylamide-based polymer and mineral oil. It is a water in oil emulsion having 264 cp at 511 1/s and 80°F. 25 lb/1000 gal (ppt) NDFF was prepared by using 10 gal/1000 gal (gpt) polymer LGC loading. Weak organic acid was used as buffer to maintain pH 5 of the frac fluid system. Metal crosslinker was used to crosslink NDFF system that can work to 400°F. In total, three breakers were used in the breaker package depending on fluid stability requirement. Encapsulated breaker was designed for more than 300°F fluid stability, live breaker was designed for 250 to 300°F and low temperature (LT) live breaker was designed for application temperature below 250°F. Table 1 shows typical range of additives loading. Depending on frac fluid stability requirement, buffer, crosslinker and breakers loading were optimized and discussed in rheology section. It is important to mention that the performance of the polymer in this study might be affected by the interactions with some additives. Some effects were made on propose, as breaker case, some enhance its performance as the buffer. The listed additives in this paper are not the only ones accepted to work with the polymer proposed, but where part of the ones used for this case. Implementation of other additives is possible and correspondent polymer performance needs to conduct the evaluation of possible effects on additives implementation as they can enhance or degrade the final polymer-based gel performance.

Table 1—25 ppt nondamaging fracturing fluid (NDFF) formulation

Additive	Unit	Loading
Biocide	ppt	0.5
Polymer	gpt	10
Surfactant	gpt	2.0
Clay Control	gpt	2.5
Gel Stabilizer	gpt	3.0
Buffer	gpt	3-4
Crosslinker	gpt	0.6-0.9
Live Breaker	gpt	1-5
Encap. Breaker	ppt	5.0
LT Live Breaker	gpt	0.5-1

Rheology

Rheological testing were conducted to measure the stability of the NDFF under bottomhole conditions. Rheological properties influences fluid leakoff, which affects fracture width and fracture extension (Al-Hulail et al. 2016). Linear gel of NDFF was prepared by hydrating 10 gpt LGC polymer in fresh water added with biocide. The apparent viscosity of linear gel was measured at different temperature using a Fann 35 viscometer at 511 1/s shear rate suing R1B1 rotor bob combination. Figure 1 shows the viscosity of 25 ppt linear polymer in NDFF at different temperature. This chart was utilized to quality check linear fluid in both lab and field testing.

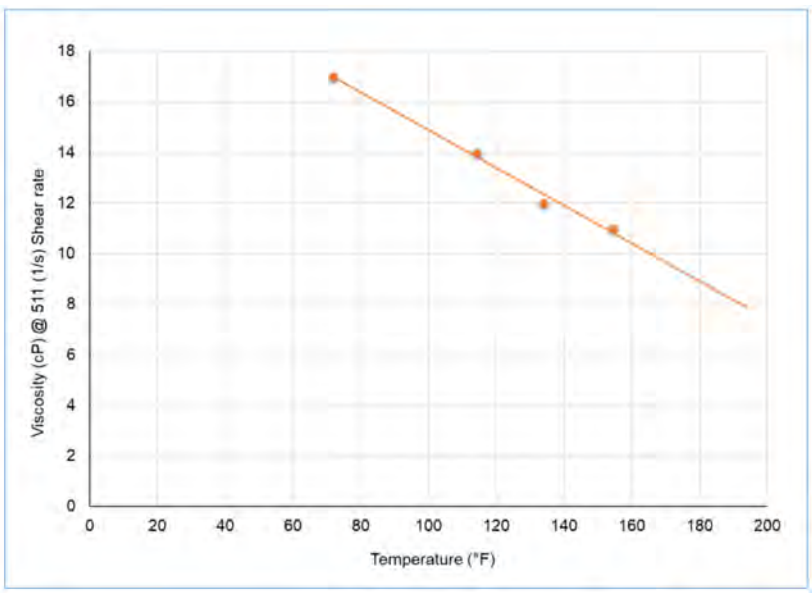

Figure 1—Linear 25 ppt NDFF viscosity at different temperature

To prepare the crosslinked NDFF, the desired amount of surfactant, clay control agent, gel stabilizer, breaker, buffer and crosslinker was added and mixed well. The pH of NDFF was adjusted to 5 using buffer before crosslinker addition. The required crosslinked/lip time was achieved by varying buffer loading. The required lip time, 3 min 30 sec was achieved using 3.2 gpt buffer loading and by maintaining pH 5 of the frac fluid system. The rheological tests were performed using shear-history simulation stated in BS ISO standard 13503-1:2003 (ISO 2003). Figure 2 shows NDFF after crosslinking.

Figure 2—Picture of fluid developed "lip" after crosslinking NDFF

Figure 3 shows NDFF fluid stability at different temperatures for one of the field trials. The fluid stability was judged by viscosity measurements with respect to time at 100 1/s with shear cycles. The fluid stability time was defined as time required reaching 300 cp viscosity at 100 1/s. The bottomhole static temperature (BHST) of selected well candidate was 290°F, which was considered for pad stage fluid optimization. The cool down temperatures, 270°F, 240°F and 210°F were considered for proppant laden stages fluid optimization. For each cool down temperature, since the encapsulated breaker is relatively stable, only live breaker loading was optimized to achieve the desired fluid stability time. The control test without breakers, shows thermal degradation rate of crosslinked fluid. The pump time for selected well candidate was 60 min so the fluid stability for pad stage was 60 min and for proppant laden stages from 60 min to 30 min as the job progress. During pad stage, NDFF could experience 290°F so lower live breaker loading of 1 gpt was optimized to get desired 60 min fluid stability. At 270°F, live breaker loading was increased to 2 and 3 gpt that gave 90 and 45 min fluid stability. At 240°F, live breaker loading was further increased to 4 and 5 gpt which gave 60 and 30 min stability. At 210°F, low temperature (LT) live breaker was introduced in addition to live breaker for aggressive breaking at lower temperature range. LT live breaker was increased from 0.5 to 1 gpt to get faster break time 40 and 28 min at 210°F and 5 gpt live breaker was also kept for additional breaking performance. In all stages, 5 ppt encapsulated breaker was also added for better fracture conductivity cleanup after closure. Optimized fluid formulation was utilized by frac engineer to design blender schedule for selected well candidate. Similar steps were followed in pre-job lab testing to conduct four different field trials for successfully field deployment of this new technology.

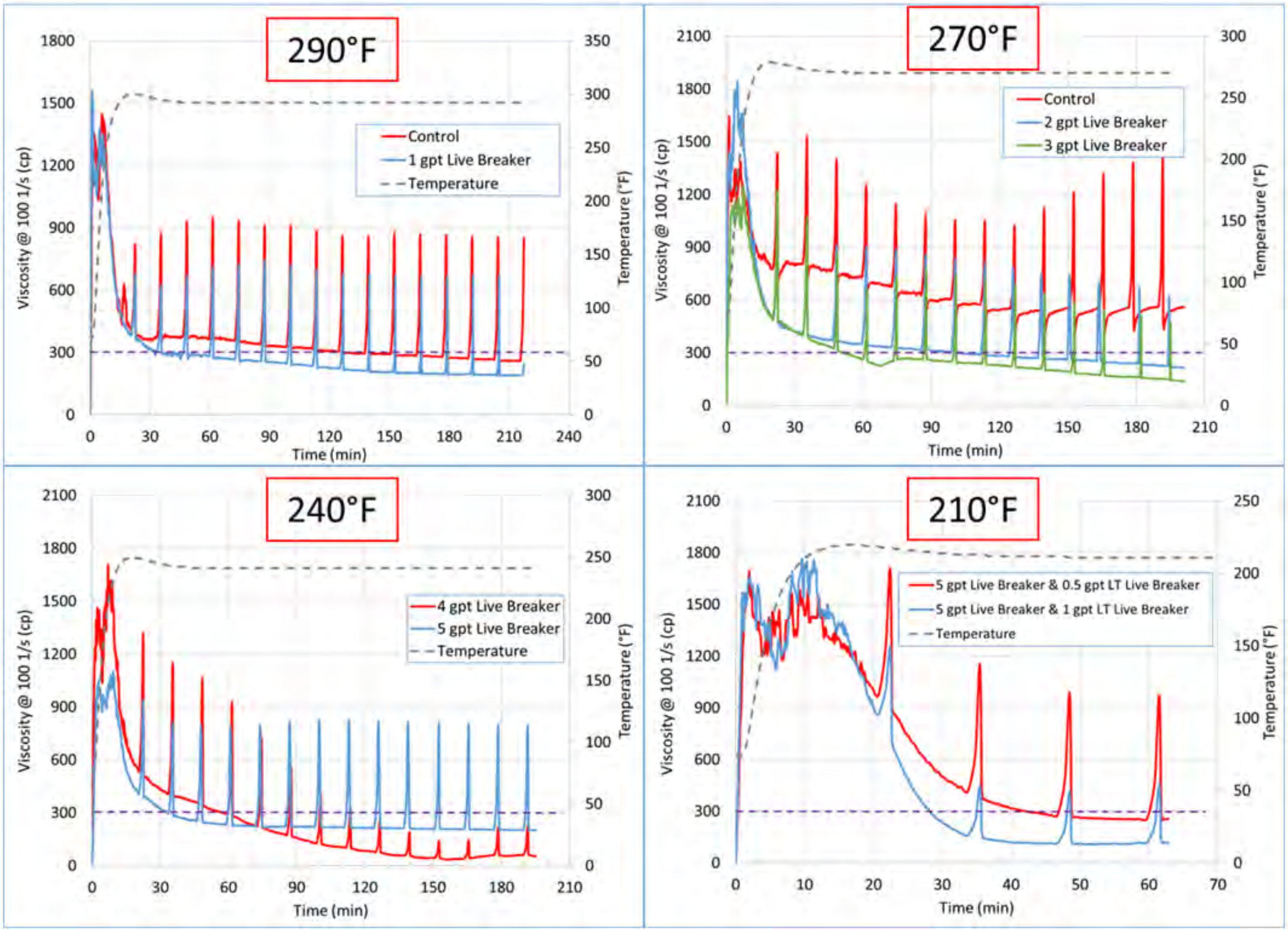

Figure 3—Crosslinked 25 ppt NDFF rheology at different temperatures

Field Execution

The NDFF was successfully field deployed in four different well candidates. Out of four, NDFF was semi-batch mixed for one field trial and for the rest of the three trials, the fluid was mixed on the fly. Before the actual field job, a yard test was performed where a tote tank full of LGC was pumped through with a liquid additive (LA) pump from blender at 21 gals/min rate for 30 min. This yard test was performed only to check LGC pumpability with LA pumps for on-the-fly mixing. Figure 4 shows typical site layout for frac operation. While during the semi-batch mixing, only linear gel was prepared in frac tanks or water tanks in batch wise, all other additives including proppant were added on the fly. Linear gel was prepared by adding desired amount of LGC polymer in tank filled with field water and the mixture was circulated by using centrifugal pump. While during the on-the-fly mixing, LGC polymer was added in LGC mixture and kept rolling. Water from water tanks, polymer from LGC mixture were sucked using blender and well mixed in hydration tank. Hydration tank has compartments where fluid gets enough residence time for full hydration. During the field job, linear gel from hydration tank, additives from chemicals trailer and proppant were mixing in blender tub and supplied to suction side of high-pressure pumps. The discharges from a series of pumps were connected to high-pressure manifold supplying the well head.

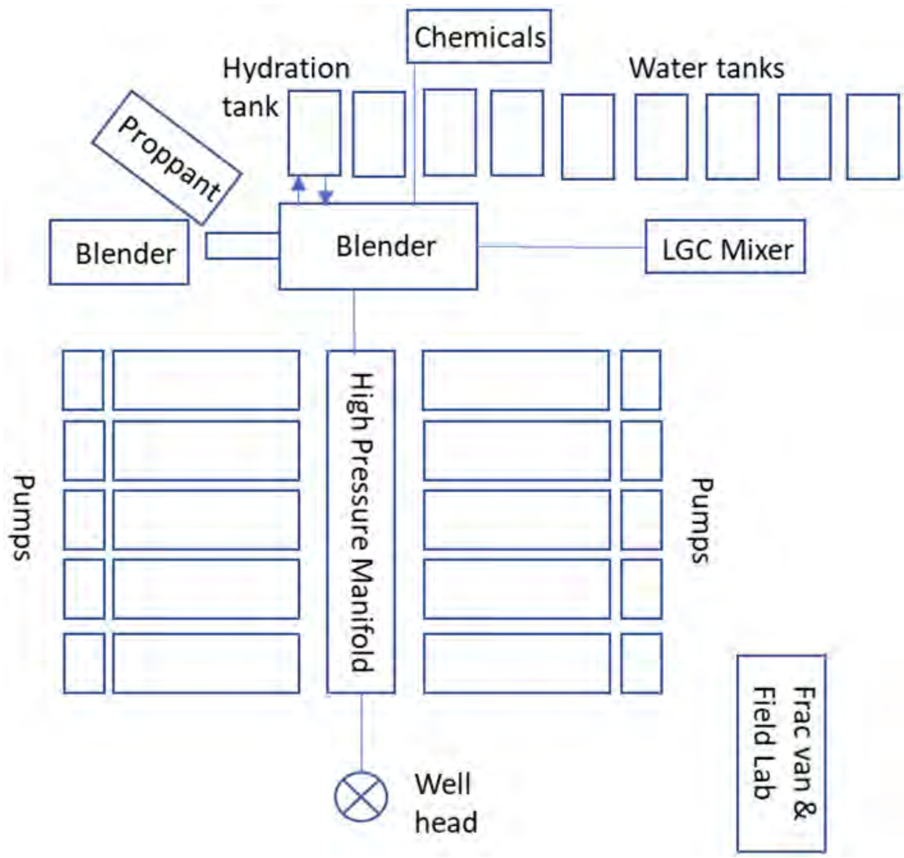

Figure 4—Typical frac operation site layout

Quality control onsite

The field case study described in this paper was pumped semi-batch wise. A 4,000 bbl linear gel was prepared by mixing eight frac tanks. Linear gel samples were collected from tank for quality control and viscosity adjustment was done by adding LGC polymer or water in tank with circulation using centrifugal pump. Table 2 shows quality control results using linear gel from each tank. The linear gel viscosity was achieved in the range from 17 to 19 cp at 511 1/s and buffer loading was measured as 4 gpt to get desired lip time and pH. Batch mixing of linear gel was very time consuming and waste fluid left in each tank bottom.

Table 2—25 ppt nondamaging fracturing fluid (NDFF) formulation

Tank #	1	2	3	4	5	6	7	8	9	10
Fluid	Water					Linear gel				Water
pH	7.7	7.1	7.08	7.12	7.13	7.15	7.18	7.21	7.08	7.57
Viscosity (cp) at 511 (1/s)	-	18	18	17	17	19	19	19	19	-
Buffer loading (gpt)	-	4	4	4	4	4.2	4	4.2	4	-
Lip Time (min:sec)	-	4:30	4:00	4:10	3:50	3:55	4:10	3:45	3:50	-
Crosslinked pH	-	5.31	5.12	5.29	5.14	5.23	5.31	5.21	5.1	-

Table 3 shows crosslinked NDFF fluid quality check during main frac job. Different samples during each stage were collected from high pressure manifold. pH and lip time of each collected sample was measured. All steps in each sub-stage were pumped as per plan except step no. 4. There was operational issue with buffer LA pump that was addressed by switching to a backup LA pump. The pH during step no. 4 was recorded as 5.7, which delayed crosslinked/lip time to 5 min and 11 sec. Figure 5 shows proppant laden NDFF collected at step no. 8 that shows uniform proppant suspension.

Table 3—Quality control of crosslinked NDFF fluid during main frac.

Step No.	Stage Name	pH	Lip time (min:sec)
1	PAD 1	5.16	2:50
2	0.5 PPA R-30/50 HSP	5.26	2:45
3	1 PPA R-30/50 HSP	5.23	2:50
4	PAD 2	5.7	5:11
5	0.5 PPA R-30/50 HSP	5.1	2:55
6	1 PPA R-30/50 HSP	5.12	3:00
7	2 PPA R-30/50 HSP	5.11	3:45
8	3 PPA R-30/50 HSP	5.16	3:50
9	4 PPA R-30/50 HSP	5.24	3:20
10	5 PPA R-30/50 HSP	5.22	3:10

Figure 5—Proppant laden crosslinked 25 ppt NDFF fluid collected during main frac job

Data frac analysis

A data frac analysis was performed using crosslinked 25 ppt NDFF without proppant to simulate main fracture treatment. The fracture diagnostic tests aids in designing and completing the main hydraulic fracturing treatment. This analysis helps to obtain more representative estimates of an instantaneous shut-in pressure (ISIP), fracture gradient, net fracture pressure, fluid friction on real conditions, fluid efficiency and fluid loss coefficients. This information was used to optimize pad volume and select the best fluid-loss additives for the main treatment and to design the pumping schedule (Mohamad et al. 2011). Prior data frac analysis, downhole gauge was placed above perforations to measure downhole pressure for enhanced fracture performance analysis and friction analysis, which was successfully retrieved before main frac treatment. Figure 6 shows the data frac treatment plot using 25 ppt NDFF. The data frac treatment was started with displacing wellbore fluids by 25 ppt crosslinked NDFF. This full wellbore displacement step was performed to obtain accurate down hole pressure readings for friction analysis. The data frac analysis was continued with step rate test by increasing slurry rate from 15 to 45 bpm with 5 bpm rise in slurry rate. After achieving the maximum slurry pumping rate, i.e., 45 bpm, 25 ppt crosslinked NDFF was pumped for 10 min. The pumps were shutdown to evaluate hydrostatic pressure for friction analysis, ISIP and pressure decline analysis. Total 577 bbl of 25 ppt crosslinked NDFF was pumped for data frac analysis. Based on data frac analysis, 11,745 psi ISIP and 10,940 psi closure pressure. Using pressure decline data, the fluid efficiency was estimated to 15%. This low fluid efficiency was anticipated due to low polymer usages. For the main frac treatment, the slurry rate was increased to 45 bpm from 40 bpm to quantify lower fluid efficiency. To improve the fluid efficiency, further improvement in fluid development is ongoing.

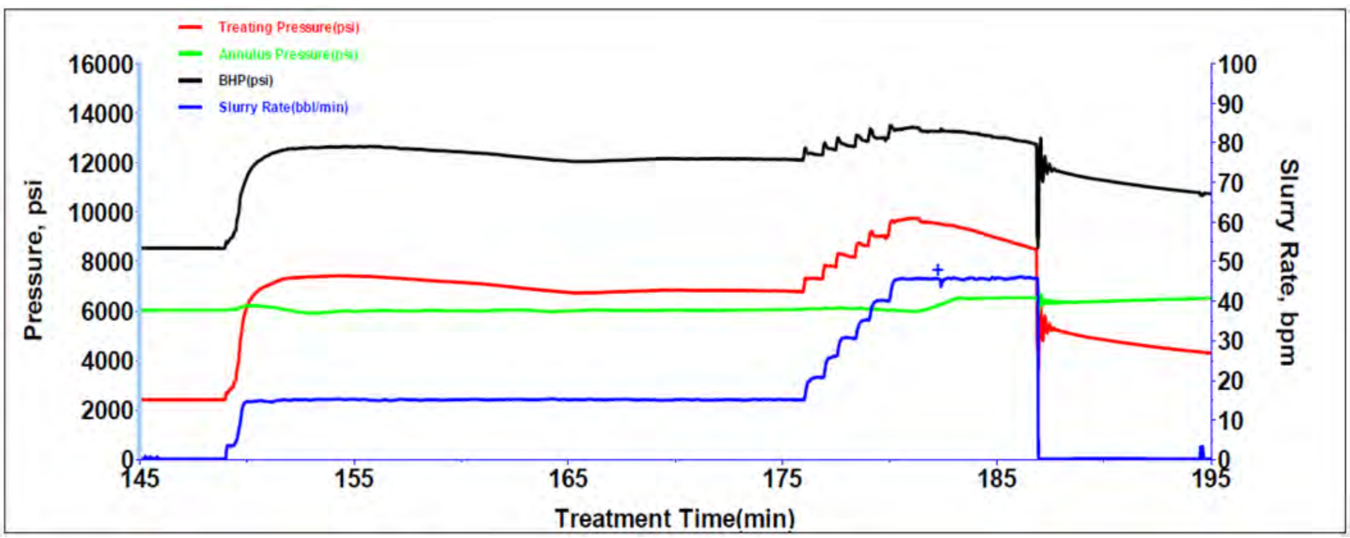

Figure 6—Data frac treatment plot using 25 ppt NDFF fluid

Friction analysis

Bottomhole treating pressure (BHTP) is critically required to design hydraulic fracturing jobs. In the absence of a bottomhole gauge, the BHTP is calculated by using surface pressure, friction pressure and hydrostatic pressure. The computed values of BHTP is subject to the assumption that the friction pressure and hydrostatic pressure calculations are reliable. While using newly developed fracturing fluid, it is critical to calibrate friction numbers for data acquisition software to estimate BHTP in understanding formation behavior during treatment. The downhole memory gauge was installed before data frac analysis and successfully retrieved after to calibrate friction numbers. This analysis was carried out using a memory gauge, Kuster K10 Quartz at a depth of 13,000 ft MD (TVD: 12,949 ft and well deviation: 24°). The friction numbers were estimated for a completion with ID of 2.93 inch. The friction pressure is calculated based on the following formula:

$$P_{friction} = P_{wellhead} + P_{hydrostatic} - BHTP \tag{1}$$

The hydrostatic pressure was calculated to 6,330 psi by subtracting wellhead ISIP from bottomhole ISIP. The bottomhole ISIP was recovered from memory gauge. This hydrostatic pressure was used in conjunction with the well head (from the surface gauge) and bottomhole pressure (from the memory gauge) to calculated friction numbers for different rates using Eq. 1. Table 4 shows friction numbers at different rate for both linear and crosslinked NDFF.

Table 4—25 ppt nondamaging fracturing fluid (NDFF) friction calibration.

Rate (bpm)	BHP_Memory Gauge (psi)	Well Head Pressure (psi)	P_Hydrostatic (psi)	P_ friction (psi)	P_ friction (psi/1000 ft)
Crosslinked 25 ppt nondamaging fracturing fluid (NDFF)					
15	12,460	6,760	6,330	630	44
20	12,625	7,260	6,330	965	67
25	12,910	7,780	6,330	1,200	83
30	13,100	8,170	6,330	1,400	97
35	13,150	8,560	6,330	1,740	120
40	13,320	9,000	6,330	2,010	139
45	13,460	9,620	6,330	2,490	172
Linear 25 ppt nondamaging fracturing fluid (NDFF)					
45	13,250	8,530	6,330	1,609	111

The friction behavior of NDFF was also compared with CMHPG frac fluid as shown in Figure 7. The NDFF showed slightly higher than conventional CMHPG frac fluid. The 25 ppt NDFF was compared with 40 ppt CMHPG frac fluid. At 40 bpm, NDFF showed 140 psi/1000 ft friction pressure where as CMHPG frac fluid showed 120 psi/1000 ft.

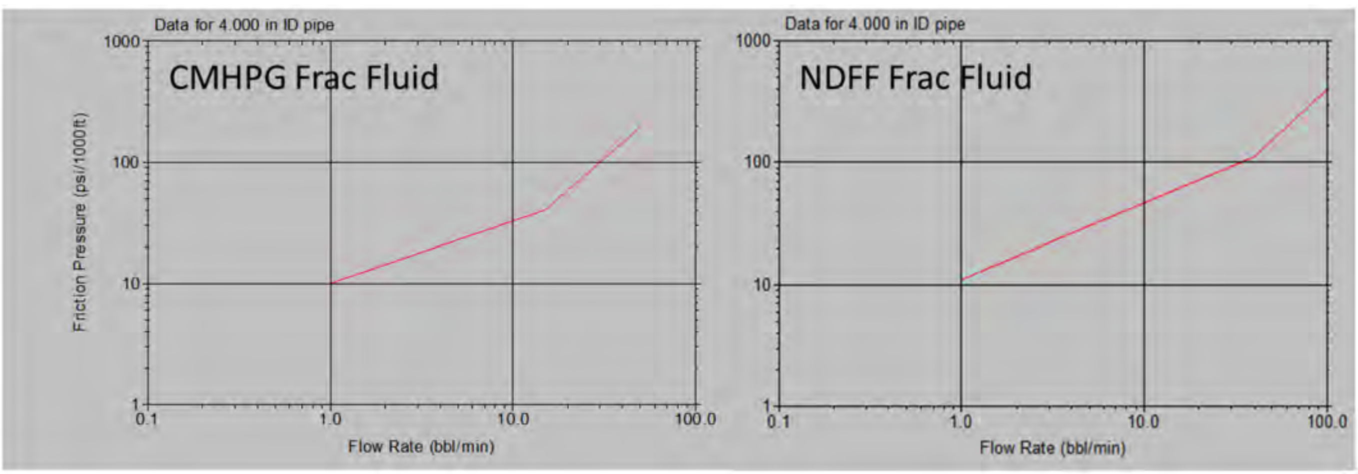

Figure 7—Friction comparison of 25 ppt NDFF with 40 ppt CMHPG frac fluid

Main Frac

The main frac with NDFF was successfully pumped without any operational issues. Table 5 shows stage design and Figure 8 shows the main frac plot. The 25 ppt NDFF was pumped with 45 bbl/min with total 3,000 bbl of slurry volume and 241,000 lb of 30/50 HSP proppant was placed. The proppant concentration was ramped from 0.5 up to 5 PPA proppant concentration. The maximum bottomhole pressure was recorded as 15,395 psi and wellhead pressure was 10,434 psi. After main frac job, ISIP was 6,775 psi and bottomhole ISIP was 12,996 psi.

Table 5—Stage design for main frac using 25 ppt nondamaging fracturing fluid (NDFF).

Step No.	Stage Name	Fluid Name	Rate (bbl/min)	Volume (gal)
1	PAD 1	25 ppt NDFF-Crosslinked	45	12000
2	0.5 PPA R-30/50 HSP	25 ppt NDFF-Crosslinked	45	4000
3	1 PPA R-30/50 HSP	25 ppt NDFF-Crosslinked	45	4000
4	PAD 2	25 ppt NDFF-Crosslinked	45	22000
5	0.5 PPA R-30/50 HSP	25 ppt NDFF-Crosslinked	45	6000
6	1 PPA R-30/50 HSP	25 ppt NDFF-Crosslinked	45	8000
7	2 PPA R-30/50 HSP	25 ppt NDFF-Crosslinked	45	14000
8	3 PPA R-30/50 HSP	25 ppt NDFF-Crosslinked	45	18000
9	4 PPA R-30/50 HSP	25 ppt NDFF-Crosslinked	45	12000
10	5 PPA R-30/50 HSP	25 ppt NDFF-Crosslinked	45	10000
11	Flush	25 ppt NDFF-Linear gel	45	8958

During flush step, a decrease in wellhead pressure was observed. It should show increase in wellhead pressure as hydrostatic pressure is decreasing due to reduction of proppant mixed slurry height. This could be caused by the higher slurry friction that was already discounted with the increase in proppant concentration. Further development in NDFF to improve friction is ongoing.

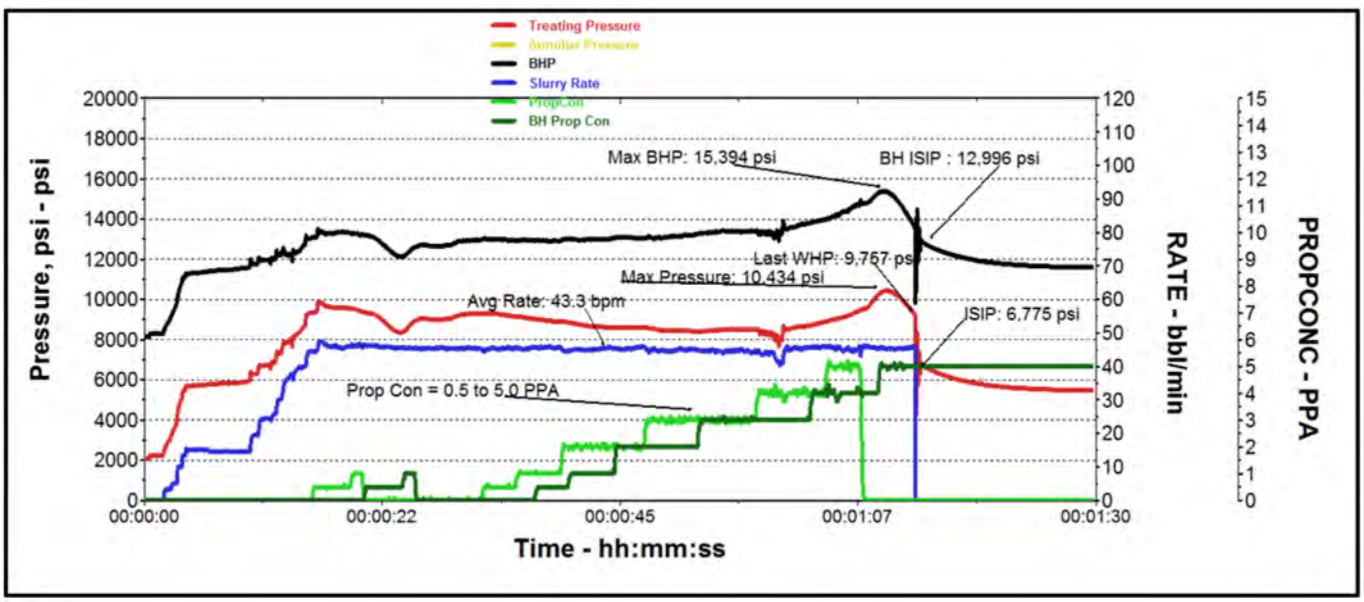

Figure 8—Main frac treatment plot of 25 ppt NDFF fluid

From Laboratory to Field Trials

Challenges from the field and the result of research and development provided path to deploy NDFF fluid system in field. For high temperature wells, guar-based fracturing fluids need to be formulated with higher polymer loading and at high pH that leaves insoluble residue, which enhances formation damage concerns. During research and development phase, polymer loading was reduced without compromising proppant carrying capacity of fracturing fluid. Thermally stable acrylamide-based polymer with reduced polymer loading of 30-40% less than guar-based fracturing fluid was developed to minimize formation damage concerns. Figure 9 shows different tasks to deploy NDFF from laboratory to field. After research and development, polymer and crosslinked package was synthesized to pilot scale with collaboration with chemical manufacturing companies. In chemical management tasks, sub-tasks like bulk size chemical manufacturing, MSDS preparation, logistic, import permit documentations, chemical handling and storage were involved. After selecting well candidate, based on water source, BHST and job design, NDFF formulation were optimized during pre-job lab testing. Based on limitations of field equipment, semi-batch mixing or on-the-fly mixing process was decided. After transporting chemicals to location, QA/QC tests of water sample and NDFF fluid system were conducted to make sure everything is going as per plan. To redesign job based on formation response, data frac analysis was conducted. Before data frac analysis, downhole memory gauge was placed above perforation to conduct friction analysis. After data frac, job was redesigned and planned for higher rate 45 bpm to mitigate less fluid efficiency due to lower polymer loading. After data frac, main frac was pumped without any operational issues. Finally, well was flowed back for flowback analysis. The NDFF was pumped in four wells having different well completions and temperatures.

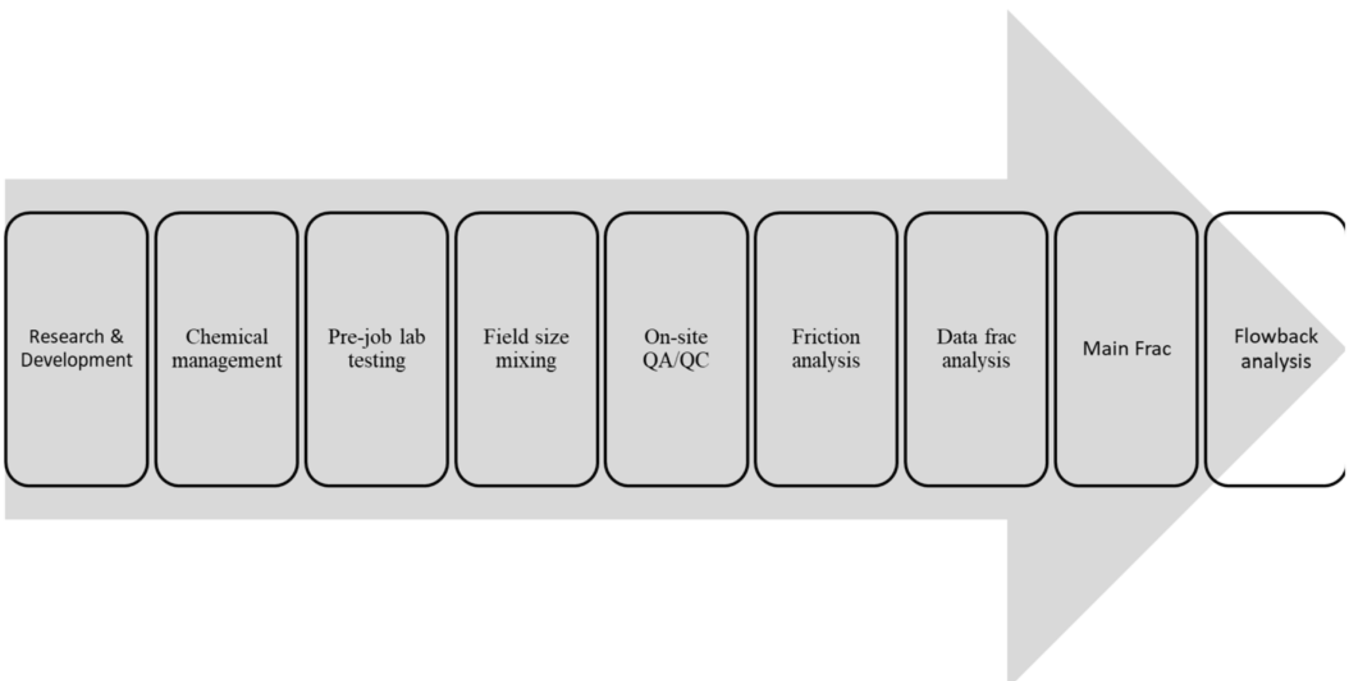

Figure 9—Different tasks involved in NDFF deployment

Conclusions

The novel acrylamide copolymer based nondamaging fracturing fluid system offers advantages over guar-based fracturing fluid such as low polymer loading, excellent high temperature stability and less formation damage. Based on efforts to transform this technology from laboratory to field following conclusion can be drawn;

- Pre-job laboratory testing allows breaker package optimization for selected well candidate with reduced polymer loading. The maximum BHST well candidate, 320°F was field tested with 25 ppt base polymer loading.
- The NDFF can be mixed in both semi-batch wise and on the fly.
- Onsite quality control gave confirmation on fluid consistence both in lab and field environment.
- During data frac analysis, friction analysis, fluid efficiency and formation response was evaluated to design main frac.

- Main frac was successfully placed with 5 ppa proppant concentration, the maximum proppant concentration was tested to 7 ppa for other field trails.
- Despite observing trend of higher friction than other polymer systems, the NDFF can confidently place proppant on regular prop frac job while increasing proppant pack retained conductivity as the amount of solid material is decreased compared with lower friction polymer systems.

Acknowledgments

The authors would like to express their sincere thanks to their colleagues Dr. Mohammed Bataweel and Justin Abel for their support during field implantation; and Brady Crane, Abdullah Garni and Ahmad Busaleh for laboratory testing.

References

Al-Hulail, I. A., Karadkar, P., Al-Janabi, Y. H., Al-Khabaz, H. and Khalifa, M. 2016. The Future of Fracture Acidizing: A Low pH, Robust, and Residue-Free Crosslinked Fracturing Fluid. Presented at the SPE Abu Dhabi International Petroleum Exhibition & Conference, Abu Dhabi, UAE, 7-10 November. *SPE-182891-MS*. 10.2118/182891-MS.

Al-Muntasheri, G. A. 2014. A Critical Review of Hydraulic Fracturing Fluids over the Last Decade. Presented at the SPE Western North American and Rocky Mountain Joint Regional Meeting held in Denver, Colorado, USA, 16-18 April. *SPE-169552-MS*. 10.2118/169552-MS.

Chong, K. K., Grieser, W. V., Passman, A., Tamayo, H. C., Modeland, N., and Burke, B. E. 2010. A Completions Guide Book to Shale-Play Development: A Review of Successful Approaches toward Shale-Play Stimulation in the Last Two Decades. Presented at the Canadian Unconventional Resources and International Petroleum Conference, Calgary, Alberta, Canada, 19-21 October. *SPE-133874-MS*. 10.2118/133874-MS.

Fink, J. K. 2003. Oil Field Chemicals. Burlington, MA: Gulf Professional Publishing, Elsevier Science.

Funkhouser, G. P. and Norman, L. 2003. Synthetic Polymer Fracturing Fluid for High-Temperature Applications. Presented at the International Symposium on Oilfield Chemistry, Houston, Texas, USA, 5-7 February. *SPE-80236-MS*. 10.2118/80236-MS.

Funkhouser, G. P. and Norman, L. 2006. Methods of Fracturing Subterranean Zones Penetrated by Well Bores and Fracturing Fluids Therefor. *US Patent No. 6*,986,391 B2.

Funkhouser, G. P., Holtsclaw, J. and Blevins, J. 2010. Hydraulic Fracturing Under Extreme HPHT Conditions: Successful Application of a New Synthetic Fluid in South Texas Gas Wells. Presented at the SPE Deep Gas Conference and Exhibition, Manama, Bahrain, 24-26 January. *SPE-132173-MS*. 10.2118/132173-MS.

Golinkin, H. S. 1979. Process for Fracturing Well Formations Using Aqueous Gels. *US Patent No. 4*,137,182.

Gupta, D. V. S. and Carman, P. 2011. Fracturing Fluid for Extreme Temperature Conditions is just as Easy as the Rest. Presented at the Hydraulic Fracturing Technology Conference and Exhibition, The Woodlands, Texas, USA, 24-26 January. *SPE-140176-MS*. 10.2118/140176-MS.

International Organization for Standardization (ISO) BS ISO Standard 13503-1: 2003. Petroleum and Natural Gas Industries - Completions Fluids and Materials - Part 1: *Measurement of Viscous Properties of Completion Fluids.*

Kefi, S., Lee, J., Pope, T., Sullivan, P., Nelson, E., Hernandez, A., Olsen, T., Parlar, M., Powers, B., Roy, A., Wilson, A., and Twynam, A. 2004. Expanding Applications for Viscoelastic Surfactants. *Oilfield Review* **16** (4): 10–23.

Ketter, A. A., Daniels, J. L., Heinze, J. R., and Waters, G. 2006. A Field Study Optimizing Completion Strategies for Fracture Initiation in Barnett Shale Horizontal Wells. Presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, 24-27 September. *SPE-103232-MS*. 10.2118/103232-MS.

King, G. E. 2010. Thirty Years of Gas Shale Fracturing: What Have We Learned? Presented at SPE Annual Technical Conference and Exhibition held in Florence, Italy, 19-22 September. *SPE-133456-MS*. 10.2118/133456-MS.

Li, L., Al-Muntasheri, G. A., and Liang, F. 2016. A Review of Crosslinked Fracturing Fluids Prepared with Produced Water. *Petroleum* **2** (4): 313–323. 10.1016/j.petlm.2016.10.001.

Liang, F., Al-Muntasheri, G. A., and Li, L. 2016b. Maximizing Performance of Residue-Free Fracturing Fluids Using Nanomaterials at High Temperatures. Presented at the SPE Western Regional Meeting, Anchorage, Alaska, USA, 23-26 May. *SPE-180402-MS*. 10.2118/180402-MS.

Liang, F., Al-Muntasheri, G., Ow, H., Cox, J. 2017a. Reduced Polymer Loading, High Temperature Fracturing Fluids by Use of Nanocrosslinkers. *SPE Journal* **22** (02): 622–631. SPE-177469-PA. 10.2118/177469-PA.

Liang, F., Sayed, M., Al-Muntasheri, G. A., Chang, F. F., and Li, L. 2016a. A Comprehensive Review on Proppant Technologies. *Petroleum* **2** (1): 26–39. 10.1016/j.petlm.2015.11.001.

Liang, F.; Li, L.; Al-Muntasheri, G. 2017b. A Non-Damaging Fracturing Fluid System for High-Temperature Unconventional Formations. Presented at the 20th Middle East Oil & Gas Show and Conference, 6-9 March 2017, Bahrain. *SPE-183673-MS*. 10.2118/183673-MS.

Palisch, T. T., Vincent, M. C., and Handren, P. J. 2008. Slickwater Fracturing: Food for Thought. Presented at the SPE Annual Ted-mica! Conference and Exhibition, Denver, Colorado, USA, 21-24 September. *SPE-115766-MS*. 10.2118/115766-MS.

Rhudy, J. S. and Knight, B. L. 1976. Fracturing Fluid. *US Patent No. 3*,938,594.

Samuel, M., Card, R. J., Nelson, E. B., Brown, J. E., Vinod, P. S., Temple, H. L., Qu, Q., Fu, D. 1997. Polymer-Free Fluid for Hydraulic Fracturing. Presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, 5-8 October. *SPE 38622-MS*. 10.2118/38622-MS.

Wang, X., Sun, H., Thou, J., Guerin, M. and Li, L. 2015. A Non-Damaging Polymer Fluid System for Conventional and Unconventional Formations. Presented at the European Formation Damage Conference and Exhibition, Budapest, Hungary, 3-5 June. *SPE-174280-MS*. 10.2118/174280-MS.

Williams, D. A., Horton, R. L., Newlove, J. C. and Chumley, R. E. 1991. Method of Treating Subterranean Formations Using a Non-Damaging Fracturing Fluid. *US Patent No. 5*,007,481.