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Contents

Controlling Undesirable Water by Applying a Composite of Nanosheet and Viscoelastic Surfactant-Based Foamed Gel

Dr. Abeer A. Alarawi, Dr. Ayman M. Al-Mohsin and Ahmad S. Busaleh

Abstract /

Excessive water production is one of the significant phenomena of reservoirs worldwide that influence oil production and costs. At the same time, a comprehensive collection of treatments is available to solve this issue, such as mechanical water shutoff, polymer-based gel, and crosslinkers-based gel. Although they all possess drawbacks, including but not necessarily limited to surface mixing and handling problems.

Foamed gel systems can enhance oil production by plugging the high water permeability zones due to their physical plugging, adsorption, dynamic trapping, and in-depth injectivity. In this study, a novel foamed gel system containing a composite of nanosheet (NS) material and a viscoelastic surfactant (VES-SURF) was developed for inhibiting undesirable water in different watercourses of high permeable zones (zones far away from the well, transient zones, and near wellbore zones). The NS VES-SURF-based foamed gel is prepared at the surface facility and then injected to control gelation time and gelling certainty.

The foamed gel stability, foamability, and rheology were examined at 77 °F to 200 °F. Foam loop rheometer experiments were conducted at 1,500 psi, and 70% nitrogen gas (N_2) quality to assess the foamed gel rheological properties and stability at dynamic conditions. A high-resolution optical microscope was utilized to detect the foam morphology and stability altering with time stability. The gelation time of the foamed gel was calculated at 77 °F to 200 °F. A viscometer was also used to measure the viscosity and thermal stability of the VES-SURF and the NS VES-SURF-based foamed gel systems at 100 °F to 200 °F.

The experimental results demonstrate that the VES-based foamed gel system converted to gel within two days, while the NS VES-SURF foamed gel requires only 90 minutes. In this foamed gel system, the gelling time can be easily controlled by altering the concentrations of NS and VES-SURF. Moreover, the VES-SURF-based foamed gel system was stable for 10 days at room temperature. In contrast, the NS VES-SURF foamed gel system was stable without any phase separation for 35 days. The VES and the NS VES-SURF-based foamed gel systems' viscosity was 1,000 cP and 1,500 cP at 100 °F, respectively. Increasing the temperature to 200 °F enhanced the viscosity of the foamed gel systems to reach 3,500 cP for the NS VES-SURF and 2,000 cP for the VES-based foamed gel systems.

The NS VES-SURF-based foamed gel is characterized by high mechanical strength, low volume, less damage, and lower cost than the traditional gel systems. In addition, the NS VES-SURF foamed gel system is stable in harsh environments, including high temperatures, salinity, and pH. Once gelation occurs, gels do not flow and distribute along the rocks due to the high viscosity of the invented system.

Introduction

Water channeling in a highly permeable layer is a significant challenge detected in oil production's middle or late stage[1]. That resulted in minimized oil production and augmented water cut[2]. Therefore, introducing water shutoff technology is desirable for oil production operations to adjust the seepage law of water and govern the water/oil production ratio or water production rate[3]. It also helps to reduce the cost of lifting, to separate, treat, and dispose of produced water[4]. The approaches available to solve this issue can be classified as mechanical or chemical methods[5]. In the mechanical water shutoff method, a separator blocks the outlet layer and prevents water from flowing into the well. This method is rarely utilized due to the sealing problem of packers and other special requirements[6].

In contrast, the chemical water shutoff method is based on injecting water shutoff additives into the well.

This approach can be grouped based on the properties of the additives to nonselective and selective water shutoff additives[7]. The typical nonselective water shutoff agents, including cement, resin, and gel, are not preferred to preserve oil flowing networks and protect oil production[8]. In contrast, selective water shutoff additives, such as partially hydrolyzed polyacrylamide and foam, can selectively block water channels without causing severe damage to the oil channels. Nevertheless, the compatibility between water shutoff additives and formation fluids plays a role in their final performance[9].

The presented additives in the literature suffer from several difficulties, including, but not necessarily limited to, surface mixing and handling problems[10]. For example, the polymer-based gel fluids' performance and stability are affected by the formation pH, salinity, and temperature in the downhole[11]. In contrast, the polymer gel fluids that crosslinked with metal salt crosslinkers, such as Al_3b, Cr_3b, Ti_4b, and Zr_4b, have low gelling stability due to difficulty controlling the gelation time because of the ionic bond crosslinking mechanism[12]. In addition, synthetic polymers, e.g., polyacrylamide and its derivatives such as hydrolyzed polyacrylamide, suffered from a lack of stability and degradation issues in the downhole conditions at high temperature, salinity, and shearing force conditions[13]. The performance of polymeric hydrogel fluid is mainly used in near wellbores because of its rapid swell to dozens of times its original volume once it contacts water[14]. Additionally, cement has excellent mechanical strength and thermal stability (450 °C); however, it cannot readily penetrate tight areas[15].

In recent years, the fabrication of foamed gel fluid has become a hot research area due to its novel characteristics. A foamed fluid is a mixture of liquid and gas phases, where the liquid phase performs as a moving phase and the gas as a diffused phase[16]. Therefore, their rheological properties rely on many factors, including gas type, surfactant, stabilizing additive, foam quality, temperature, pressure, bubble texture, shear rate, and viscosity[17]. For water shutoff application, the foamed fluid with gel as the outer phase is more stable than conventional foam and possesses water as the main component[18].

The foaming agent is a chemical that facilitates the formation of foam. Therefore, it must adhere to conditions, including low interfacial tension, high foaming ability, compatibility with formation water (easily soluble, without precipitation), and stability under formation conditions[19]. This agent is mainly surfactant, where the amount of surfactant included in the water shutoff treating formula determines the required viscosity to govern the water and gas production rate[20]. A foaming stabilizer is a chemical that enhances foam stability by increasing the fluid viscosity and decreasing the delivery rate of the fluid film between the liquid and gas phases[21]. Therefore, it must have the following characteristics: solid thickening ability, compatibility with the foaming agent and formation water, and stability under formation conditions[22].

Nanosheet (NS) material is a single layer structure where the carbon atoms form a 2D hexagonal lattice. NS material has been widely studied due to its exceptional characteristics and relevance to various fields, such as being lightweight and thin, its flexible electric/photonics circuits, and use for solar cells, various medical, chemical, and industrial applications. NS material is a good candidate for application within the oil industry[23], owing to its ability to enhance several base fluid properties, such as fluid flow, fluid loss control, wettability changes, emulsion stabilizers, and electrical and thermal conductivity.

The enormous surface areas per NS material volume dramatically increase the NS material's interfacial interaction and surrounding fluid molecules[24]. These surface areas can serve as sites for bonding with fluid molecules and influence the composite crystallization, chain entanglement, and morphology, thereby improving the foamed gel system viscosity[25]. In addition, nitrogen gas (N_2) is selected to prepare the foamed gel formula due to its stable chemical characteristic. It can be separated easily from the air by membrane separation (low-cost)[26].

In this research study, a developed foamed gel formula comprised of NS material and a viscoelastic surfactant (VES-SURF) was developed for inhibiting undesirable water in different watercourses of high permeable zones — zones far away from well, transient zones, and near wellbore zones — at high temperature conditions, 77 °F to 200 °F. Its outstanding characteristics include:

- The ability to deeply penetrate rock matrix and tight reservoirs.
- It possesses high mechanical strength, low volume, causes less damage, and lower cost than the traditional gel formulas that have been utilized for water shutoff applications.
- The viscosity and gelling time of the NS VES-based formed gel can be controlled by altering the NS and VES-SURF concentrations.
- The developed foamed gel system is stable in harsh environments, including high temperatures, salinity, and pH.
- The NS VES-based formed gel is prepared at the surface facility and then injected to avoid drawbacks, such as the lack of gelation time and gelling uncertainty.
- The NS VES-based formed gel can cover a wide range of temperatures from 77 °F to 200 °F.

Materials

Commercially available VES-SURFs were utilized to prepare the foamed gel system. The surfactant's critical micelle concentration was nearly 1 wt% to 2 wt% at 25 °C. The NS was used in a powder form. The NS (purity of > 99.8 wt%) is nearly spherical. N_2 was used with a purity of (99.9 wt%). All the dispersions were mixed using deionized water.

Method

Preparation of NS SURF Dispersions

The foamed gelling solutions were formulated with 100 ml of brine water, 0.7 g of NS, and 7.5 ml to 10.5 ml of VES-SURF. The dispersion was stirred for 24 hours at high revolutions per minute to ensure homogeneity.

Preparation and Characterization of Foamed Gel Systems

Foamed fluids were statically examined by measuring foam half-lifetime. In addition, the influence of temperature and additives on foamability and stability was also studied. The warning blender method prepared the NS SURF-based foamed fluid where 100 ml of the NS SURF dispersion was mixed for 15 minutes at a high shear rate. Then, the prepared foamed dispersion was transferred to a sealed cylinder to record the decaying foam time (half-lifetime measurements) at 77 °F to 200 °F using an atmospheric oven pressure. In addition, dynamic foam viscosity, micromorphology, and thermal stability were evaluated using a foam loop rheometer and microscope instrument. A foam loop rheometer was utilized to investigate the effect of dynamic conditions on the foam's stability and rheological properties.

Several tests were conducted at shear rates of 300 S^{-1}, 275 °F to 350 °F, 1,500 psi, and 70% N_2 quality using a high-pressure, high temperature foam rheometer system (Chandler Engineering, Model 8500-3K), Fig. 1. The working mechanism of the instrument is as follows: a Coriolis flow meter provides the mass flow measurement of the sample. The differential pressure between the tube's two ends is measured using differential pressure transducers (high and low ranges). The shear rate and stress of the fluid flow through the pipe were calculated using Eqns. 1 and 2. The N_2 quality was calculated from the obtained liquid and gas mixture mass measurements. A high-resolution optical microscope was used to observe the morphological structure of the foams during dynamic testing, including a view cell and light bulb, Fig. 2.

$$Shear\ Rate\ (\gamma), s^{-1} = \frac{8 \times Velocity}{Tube\ ID} \quad (1)$$

$$Shear\ Stress\ (\tau), {}^{lb_f}/_{ft^2} = \frac{Tube\ ID \times Differntial\ Pressure}{4 \times Tube\ Length} \quad (2)$$

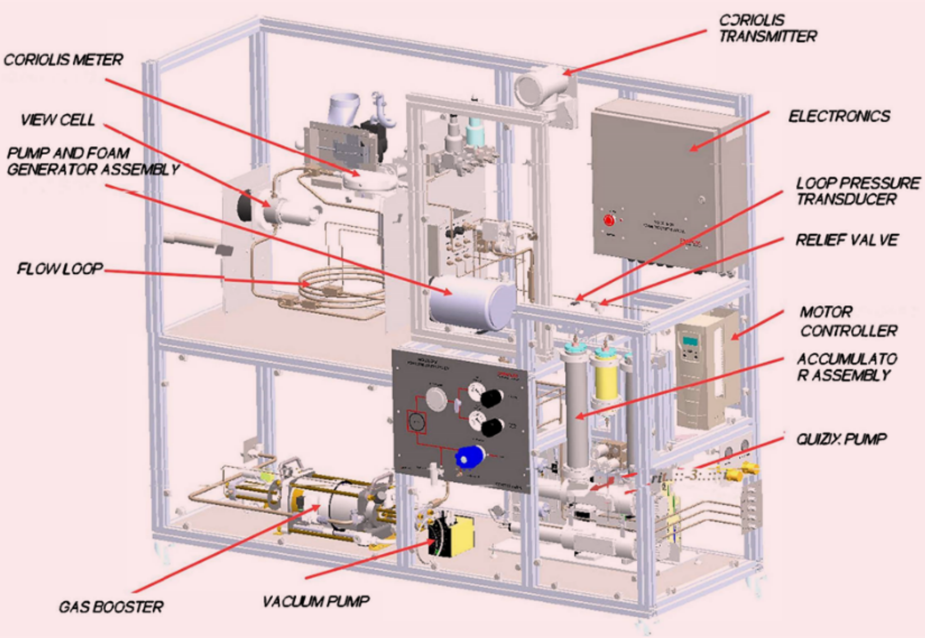
Results and Discussion

Foamed Fluid Rheological Characteristics

The viscosity of a foamed fluid is vital to a successful water shutoff operation, due to the fluid's unique structure comprising microstructure-size bubbles. Several factors significantly govern the foamed fluid's viscosity, such as altering volume fraction, stability, and scale of the bubbles over time[27]. The results obtained from the foam loop rheometer demonstrated the changing of foam viscosity with a time of several foamed

Fig. 2 *The class oven includes a flow loop, Coriolis flow meter, view cell, and a light bulb assembly.*

Fig. 1 *A schematic of the dynamic foam loop rheometer system (Chandler Engineering, Model 8500-3K) manufactured by AMETEK Inc.*



fluids stabilized by either a SURF or a NS SURF composite at fixed shear rates of 300 S^{-1}, 70% N_2 quality, 1,500 psi, and a wide range of temperatures (275 °F to 350 °F), Fig. 3.

At the beginning of the experiment, the viscosity of SURF-based foam (5 vol/vol%) reached 37 cP at 275 °F and then decreased with time to 22 cP to 26 cP at temperatures of 300 °F to 350 °F, respectively. We believe that the increase in liquid drainage and the coalescence of the bubbles with increasing temperature is a reason behind the decrease in viscosity, which negatively contributed to the foam's quality and stability.

In contrast, the viscosity of the NS SURF composite-based foam (3.0 vol/vol% NS and 5.0 vol/vol% SURF) exhibited a slightly low value (28 cP at 275 °F), followed by a sharp rise to 45 cP at 350 °F. The NS SURF composite-based foam's viscosity at a temperature of 350 °F was two times that of the SURF-based foam, confirming the significant impact of the NS on minimizing foam rupture and improving foam stability at high temperatures. This was because of the strong adhering capability of the NS SURF particles on the surface of bubbles that protects the foam from deformation.

Foam Film Microstructure

Altering of the foam's microstructure with time was also studied to elaborate on the dynamic foam stability. Figure 4 presents the microstructure film of foams stabilized by the NS SURF composite and SURF at 300 °F.

The bubble size of the SURF-based foam was small, and

Fig. 3 *The foam's viscosity behavior curves at a wide range of temperatures, 275 °F to 350 °F, of foamed fluids stabilized by a SURF and a NS SURF composite at 300 S-1, 70% N_2 quality, and 1,500 psi.*

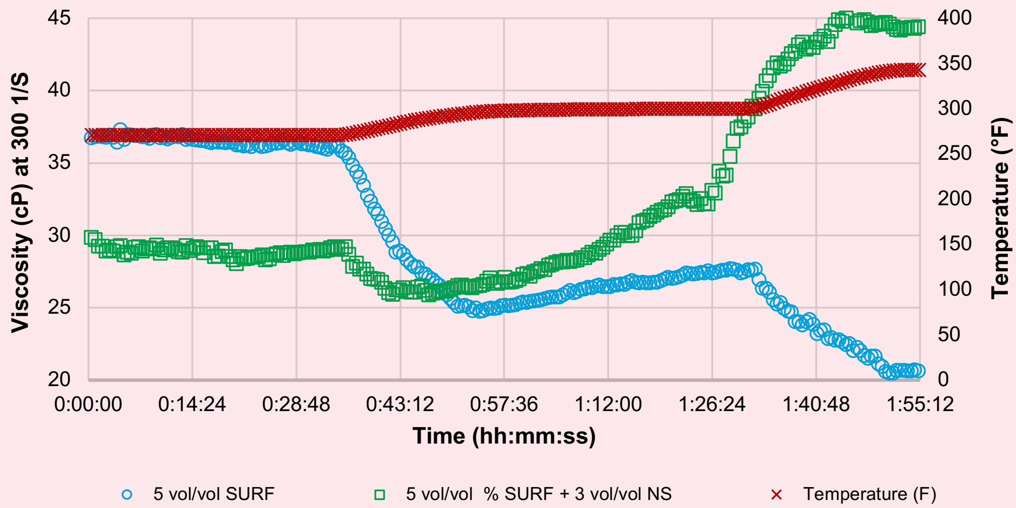
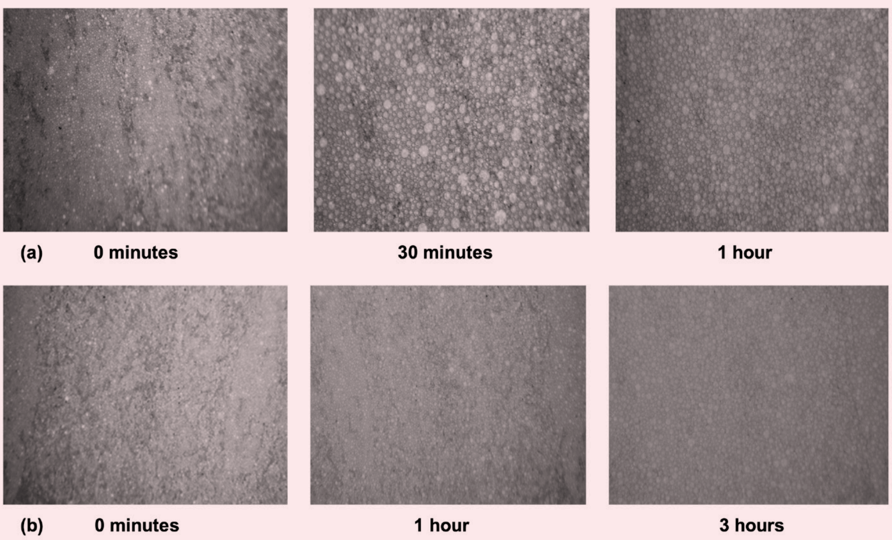


Fig. 4 *The foam film morphologies of the foamed fluids stabilized by (a) SURF, and (b) NS SURF at 300 °F.*



the bubbles' population was enormous. Then, after passing 30 minutes of imaging time, the bubbles were expanded and converted to a hexagonal shape. The bubbles demonstrated less compactness because of foam drainage caused by the Young-Laplace phenomena (the merging between big and small bubbles driven by the pressure difference). In comparison, the bubbles of the NS SURF held in reserve their hexagonal shape and population for about three hours, reflecting the vigorous foam morphology that supports the foam resistant bubble's collapse and drainage.

The long foam film stability of NS SURF-based foam is attributed to outstanding NS characteristics such as robust adsorption capability, high specific surface area, and temperature resistance. As a result, it enhances the bonding between NS particles and surfactant molecules to accumulate at the bubble surface. This particle behavior prevents foam from deformation by forming a supportive film between foam-liquid phases.

Foamed Gel System Characterizations

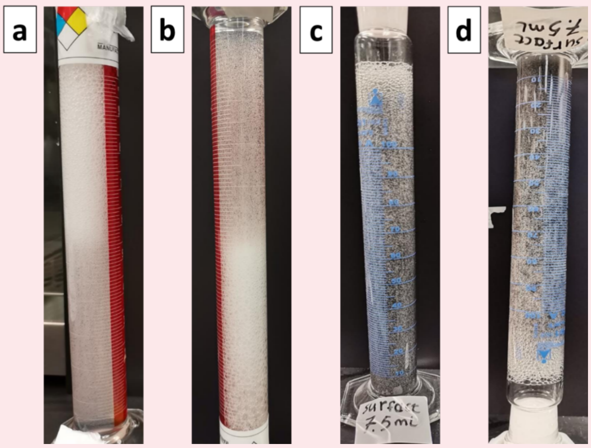
Gelation time is required to convert a gel solution from its liquid phase to a high viscosity robust gel. The experimental results demonstrated that the SURF-based foamed solution converted to gel within two days, while the NS SURF foam requires only 90 minutes at room temperature, Figs. 5a to 5d.

The SURF-based foamed gel system was stable and remained as a foamed gel for 10 days at room temperature, Figs. 6a and 6b. In contrast, the NS SURF foamed gel system was stable without any phase separation for 35 days, Figs. 6c and 6d.

The foamed gels system displayed excellent thermal stability at 200 °F, Figs. 7a to 7d. The SURF and NS SURF-based foamed gels preserve their robust gel structure for 10 and 24 days of assessment at 200 °F.

A viscometer was also utilized to measure the viscosity, and thermal stability of the SURF and NS SURF-based foamed gel systems at 100 °F to 200 °F, 10 S^{-1}, and 500 psi. Figure 8 illustrates the viscosity diagram of the SURF and NS SURF-based foamed gel systems at 1,000 cP and 1,500 cP, respectively, at 100 °F. Increasing the testing temperature to 200 °F increased the viscosity of the NS SURF-based foamed gel system, reaching 2,000 cP and 3,500 cP for the SURF-based foamed gel system at 200 °F. The NS SURF-based foamed gel showed a higher viscosity than the SURF-based foam gel at 100 °F to 200 °F.

Fig. 5 The gelation time of the foamed gel systems at room temperature of: (a) SURF-based foamed gel system once prepared, (b) once gelled after two days, (c) NS SURF-based foamed gel system once prepared, and (d) once gelled after 90 minutes.



Conclusions

The research results confirmed that the stability and rheological characteristics of the foamed gel systems were enhanced after introducing the NS SURF composite as a stabilizer agent; this is an essential achievement for a foamed gel that is prepared and injected from a surface to a high temperature reservoir. Several static and dynamic foamed gel characteristics were examined by applying numerous characterizing techniques, and the following conclusions were drawn:

- The foam's stability of the NS SURF-based foam improved

Fig. 6 The stability results of the foamed gel systems as a function of time at room temperature of: (a) VES-based foamed gel system once prepared, and (b) after passing 10 days. (c) The NS SURF-based foamed gel system once prepared, and (d) after passing 35 days of assessing.

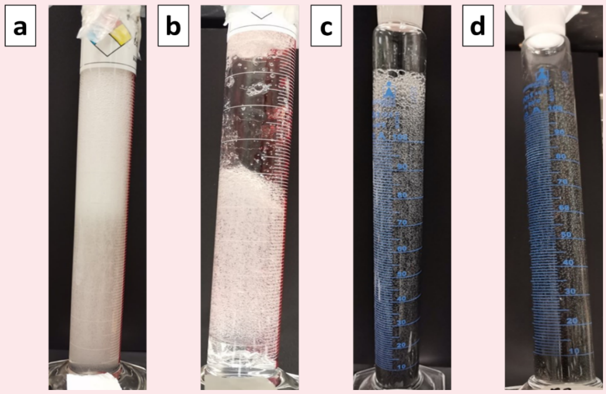


Fig. 7 The thermal stability results of the foamed gel systems once prepared: (a) SURF and (b) NS SURF-based foam gels, and (c) SURF-based foamed gel after passing 10 days, and (d) NS SURF-based foamed gel after passing 24 days of assessment at 200 °F.

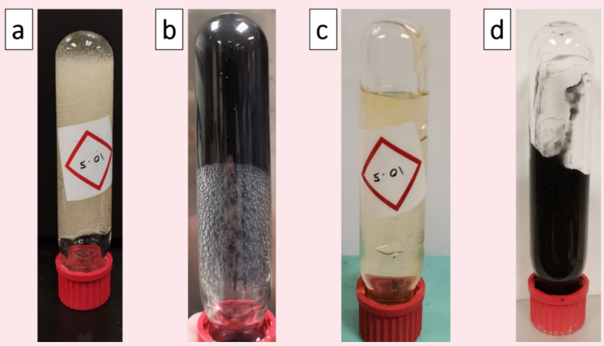
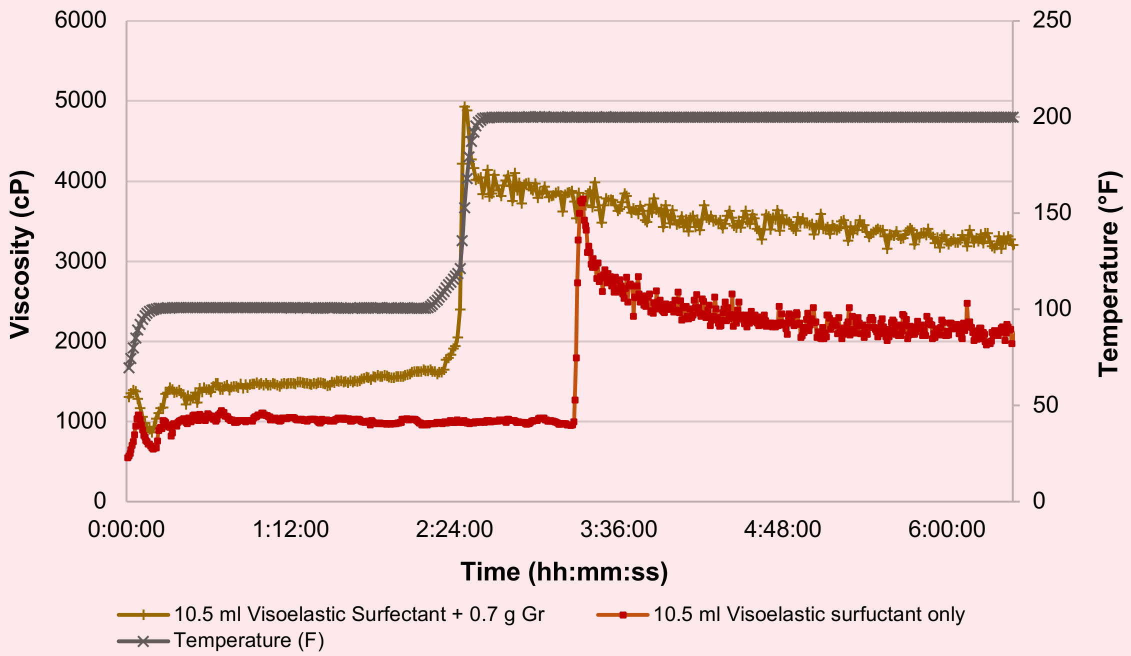


Fig. 8 A viscosity diagram of the VES and NS VES-based foamed gel system at 100 °F to 200 °F.



by approximately 20% to 50% compared to the foam stabilized by a SURF only.

- The dynamic viscosity of the NS SURF-based foamed gel was doubled that of the SURF foamed gel at 275 °F to 350 °F, 300 S^{-1}, 1,500 psi, and 70% N_2 quality.
- The foam's NS SURF composite microstructure demonstrated a firm texture and colossal population compared to the SURF-based foam at 300 °F.
- The temperature impact on the SURF foamed gel was reduced after applying the NS SURF composite as a stabilizer at 100 °F to 200 °F.
- At room temperature, the gelation time of the foamed gel systems was two dyes for the SURF-based foamed gel. In contrast, the gelation time of the NS SURF-based foamed gel was 90 minutes at room temperature.
- The thermal stability of the SURF-based foamed gel was 10 days, while the NS SURF-based foamed gel was 24 days at 200 °F.
- The viscosity of the foamed gel stabilized with the VES and NS VES was increased with increasing the temperature from 100 °F to 200 °F.

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Experimental Investigation of a Novel Nanosilica for Blocking Unwanted Water Production

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Abstract /

Nanotechnology is the design and application of engineered nanoparticles with one minimum dimension in the range of 1 to 100 nanometers. To achieve a specific target, innovative methods are highly required to overcome the challenges in the oil and gas industry, such as undesired water production. Herein, we present an advanced nanosilica, a new eco-friendly, cost-effective, and promising approach to control undesirable water production.

The objective of this work is to evaluate our nanofluid system that can be used for water management in different water production mechanisms, including: high permeability streak, wormhole, and fractured reservoirs. A systematic evaluation of the novel nanosilica/activator for water shut-off application requires an examination of the chemical properties before, during, and after gelation at given reservoir conditions. The placement of this water shut-off system is highly dependent on gelation time and viscosity. Therefore, we emphasize in this study the investigation of these gelation kinetics by conducting extensive rheology experiments at varied temperatures and activator concentrations. We have looked into evaluating the optimum breaker for the gel as a contingency plan for improper placement.

Measurements of the nanosilica fluid's initial viscosity exhibited a low viscosity, less than 10 cP at normal temperature and pressure conditions; this provides a significant benefit for mixing at the surface and pumping requirements for pilot testing. The nanosilica gelation time can be tailored by adjusting activator concentration to match field job design at a given temperature, which is more than 200 °F. The gelation time revealed an exponential relationship with temperature and reversible proportionality. The nanosilica gel proved to be a thermally stable fluid system along with different activation ratios. For breaker tests, the gelant fluid showed complete breakdown at altered temperatures to mimic downhole conditions. Our lab observations conclude that nanosilica fluid is verified to be acceptable as a water shut-off system for field applications.

This novel nanofluid system is a promising technology to control water production from oil wells. The system has low initial viscosity that can be injected in porous media without hindering the injectivity and becoming at risk of fracking the sand. In case of inappropriate placement, the fluid can break down entirely using a non-damaging chemical breaker instead of using mechanical approaches that might damage the completion.

Introduction

Water produced together with the hydrocarbons is considered as an undesirable byproduct in the oil industry. Excessive water production not only reduces the economic efficiency of the oil and gas wells, but also brings other severe problems such as corrosion and scale, fine migration, and hydrostatic loading. In addition, lifting, separation, processing, and disposing of the unwanted water will add a significant increase to overall operational costs for oil companies[1, 2].

Treatments dealing with the undesired water production can be either mechanical or chemical methods. The mechanical methods are limited to the application of specific completion tools and might be effective only near the wellbore[3]. The chemical methods, depending on the chemical materials used, usually involve the injection of chemical solutions into the formation, which form gels at the reservoir conditions to block the unwanted water. These solutions are prepared on the surface in a way that when pumped into the treatment zone, they will have sufficient time to reach the target areas before forming a gel under reservoir conditions. These chemical systems can help in addressing the unwanted fluid not only in near wellbore areas, but also at the formation depths away from the wellbore[4].

Various chemical systems were developed for controlling excessive water production over the past decades. These include cement, silicate gels, resins, and polymer gels[5, 6]. Among these, the polymer gel systems often represent a more cost-effective method for water control applications compared to mechanical isolation. The polymer gel system mainly consists of a mixture of polymer and crosslinker, called gelant, and is injected to target the formation. A crosslinking reaction then occurs by using a specific trigger to generate in situ bulk gels at reservoir temperature[7,8]. Polymer gels have been widely applied as a water control agent for decreasing water production in mature oil fields[9].

This gel system, however, still has several disadvantages that limit its applications. Among the limitations commonly known are the lack of precise control on gelation time, polymer degradation at elevated temperature, and separation between polymer and crosslinker[10,11]. To overcome these limitations, many research groups have looked into and implemented chemical systems other than in situ polymer gels, proposing preformed sized particle gels (ppg)[11,12], pH sensitive gels[13,14], bright water[15,16], micro- and sub-microgel[17].

Gelation is considered as the crucial characteristic in designing chemical treatment for water control. Gelation phenomena occur when low viscosity chemical dispersion is converted into a viscous gel. Sometimes, the gel formation process is rapid and unpredictable. In field applications, we have planned a way to delay gelation time at elevated temperatures to allow sufficient time to complete the injection chemicals; which is necessary to develop gel strength. For example, when applying gel for in-depth water shut-off, the gelation time must be sufficient to achieve deep placement. Consequently, the gel forming composition offers a reliable barrier against water influx into oil producing wells. Controlling the gelation time can be achieved by varying the concentrations of the components of the composite[18,19].

In recent years, nanotechnology has found wide applications in the oil industry due to the development of new nanomaterials. Nanotechnology has had a revolutionary impact on almost all aspects of the oil industry; from drilling, completion, enhanced oil recovery, sensing and imaging techniques to stimulation techniques in oil and gas migration and accumulation[20,21]. Inspired by these innovations, researchers have extensively explored the potential of using nanomaterials in oil field water management.

A novel nanosilica-based fluid system has been proposed and found to be a promising technology for controlling undesirable water production in oil and gas fields. The novel nanofluid system is comprised of surface modified nanosilica particles and an activator. It has low initial viscosity and can be pumped as a single-phase solution upon placing it into the targeted zones. The gelation process is mainly activated by the formation temperature, and by tuning the composition, delayed gelation can be achieved, which could allow sufficient time for placement operation. The factors that will affect the stability of the nanofluid and gelant has systematically been studied[22,23].

In this article, we evaluated the novel nanofluid for water shut-off applications targeting possible water production mechanisms of high permeability streak, wormhole, and fractured reservoirs. Focusing on investigating the gelation kinetics of the novel nanofluid, extensive experiments on rheology have been conducted in a systematic way to examine the effect of temperature and activator concentrations on gelation time at given reservoir conditions.

Analysis of the substantial testing results on the gelation kinetics has revealed an exponential relationship of the gelation time with temperature and this can be reversible proportionally. This will provide critical information for designing the placement job and guiding the field operation. In addition to the gelation study, breaker tests are also performed as a contingency method. The results confirm the novel nanofluid gel could break down completely at altered temperatures using non-damaging chemicals.

Experimental Studies

Materials

The nanosilica system is an aqueous solution consisting of surface modified nanosilica with a liquid activator. The nanosilica is dispersed and includes approximately 40 wt% of colloidal silica nanoparticles. These colloidal silica particles are sterically stabilized. The silica nanoparticles have a negative surface charge, discrete, and smooth spherical shape. The activator is triggered by temperature. Therefore, when combined, the nanosilica with an activator will generate the water shut-off system at reservoir conditions.

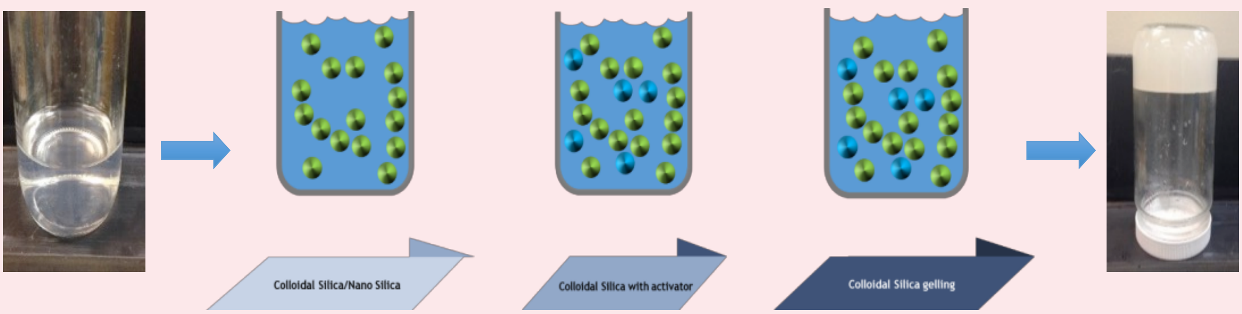
Figure 1 summarizes the steps of the gelation process for nanosilica fluid. Furthermore, to break the developed gel system, we tested a liquid breaker solution, which is composed of water and solid material.

Gelation Time Experiments

For water shut-off gel systems, the initial gelation time is referred to as the time reached once the viscosity raises dramatically. For field-testing, the gelation time is crucial to enable a smooth on-site mixing, allowing safe pumping operations to eventually deliver the nanosilica fluid into the target layer with sufficient setting time. The methodology we used in our study to determine the gelation time was the rheology test.

A high-pressure, high temperature rheometer is utilized to

Fig. 1 *A schematic representation of the gelation process for a nanosilica system.*



detect the drastic change in fluid viscosity against time while running a rheology test at bottom-hole conditions. We conducted all rheological experiments at a fixed shear rate at 10 s^{-1} and monitored the sample viscosity over time, Fig. 2.

Breaker Tests

In case the water shut-off gel is solidified in the wellbore, a contingency plan has to be made to break the gel system. Consequently, we studied the ability to break the nanosilica gel system at a fixed reservoir temperature equivalent to 210 °F. We prepared and optimized breaker solutions by dissolving non-damaging breaker particles in field water at varied breaker concentrations.

Test Results and Discussions

Preparation

The rheology experiments were conducted using a nanosilica water shut-off system at a wide range of temperatures, between 140 °F and 210 °F to mimic downhole temperatures. The nanosilica system was prepared by mixing a nanosilica solution with a liquid activator at room temperature. The resultant nanofluid is a single-phase solution with low initial viscosity below 10 cP under a shear rate of 511 s^{-1} at ambient conditions. Then, the mixed solution was transferred to the rheometer cup, heated, and pressurized at the desired temperature while fixing the shear rate to 10 s^{-1}.

Effect of Temperature

To examine the effect of temperature on the viscosity development and gelation time, we utilized four nanosilica solutions at which all have the same formulations. Figure 3 represents the viscosity profiles against time of the four nanosilica samples, prepared using a 40 wt% activator. It is clear from Fig. 3 that at 190 °F and 210 °F, the gelation time was less than an hour.

Furthermore, as the temperature cools down, the gelation time

Fig. 2 The gelation time determination through a viscosity measurement at 500 psi and 170 °F.

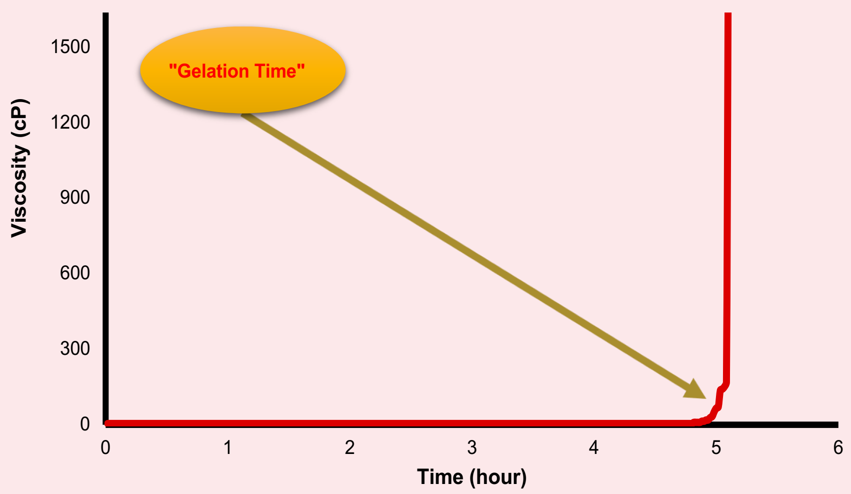
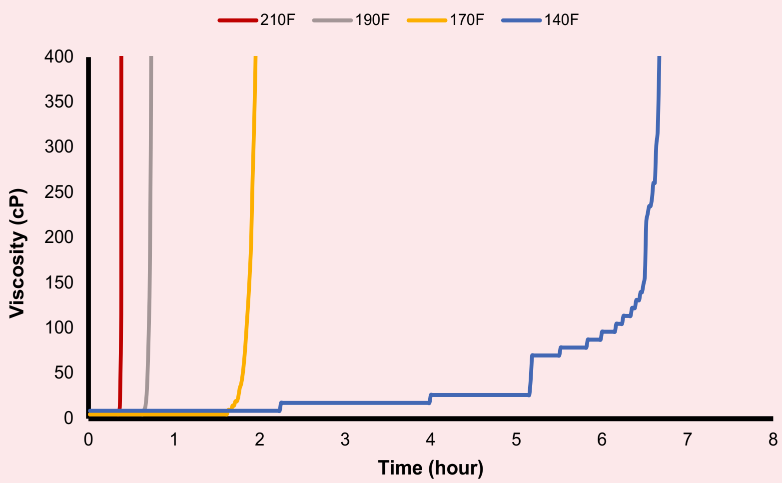


Fig. 3 The effect of temperature on gelation time and viscosity using nanosilica with a 40 wt% activator.



increases and shifts to the right. To elaborate more, by comparing the heated samples at 170 °F and 140 °F, the gelation time was roughly 1.5 hours and 6.5 hours, respectively. Moreover, when the gelation started, the viscosity of the nanosilica with a 40 wt% activator increases intensely at 210 °F, 190 °F, and 170 °F, compared to the sample 140 °F.

Subsequently, during field-testing, it is crucial to consider the cool-down effect of the reservoir while pumping the nanosilica fluid to design the optimum water shut-off formulation and volume.

Gelation Kinetics

The analysis of gelation kinetics was implemented using experimental rheometer tests in addition to the previously presented experiments, Fig. 3. Based on the conducted experiments, we found that the gelation time of the nanofluid at 40 wt% with a fixed activator concentration, has an exponential relationship with the sample temperature. The relationship between gelation time (GT) and sample temperature (T) was developed using the Power-Law trendline option from Excel software.

Based on the collected pairs (GT_i, T_i) of data from each lab test, the gelation time is plotted against the temperature to generate the regression module, Fig. 4. This correlation is beneficial to understand the cool-down effect of the formation temperature on gelation time for the nanosilica fluid containing a 40 wt% activator.

Fig. 4 *The regression module of gelation time in terms of temperature with an activator concentration of 40 wt%.*

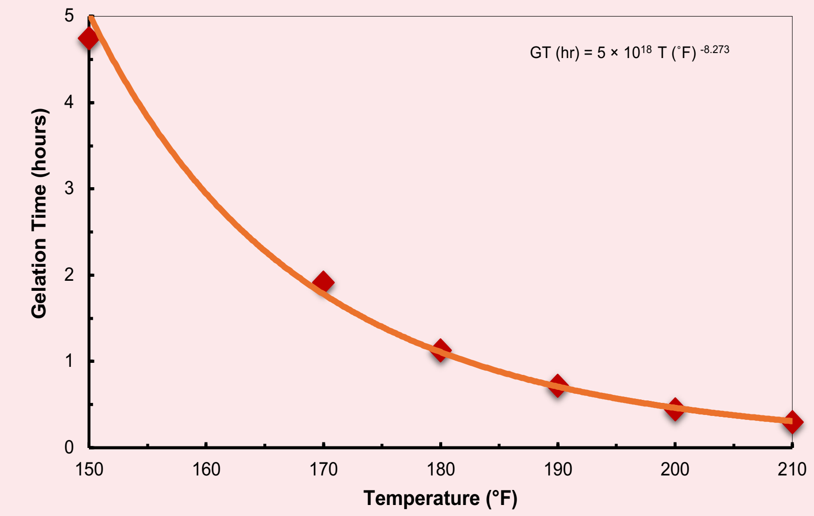


Fig. 5 *The regression module of the activator in terms of gelation time at 200 °F.*

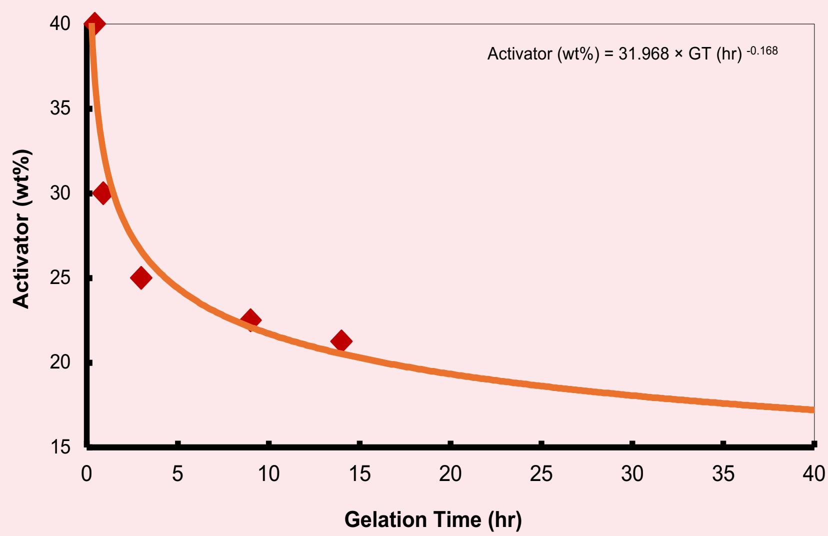
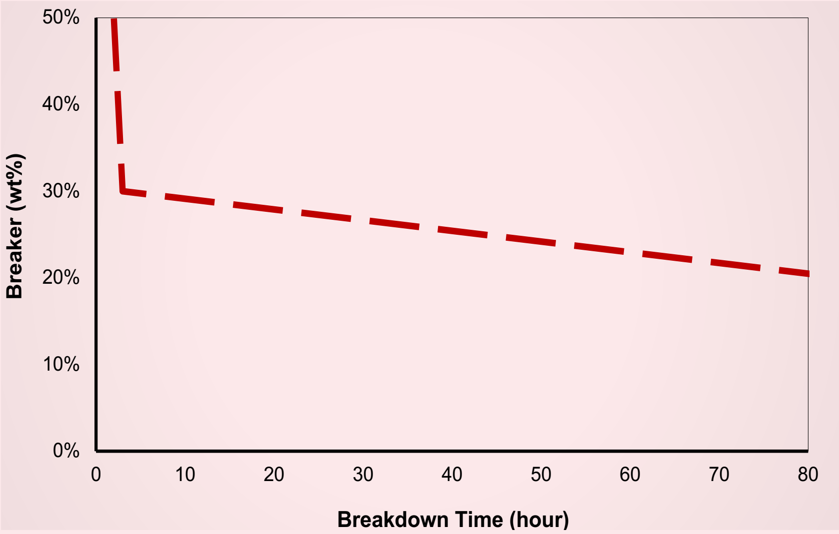


Fig. 6 The effect of the breaker concentration on the nanosilica gel breakdown at 210 °F.



Activator Kinetics

We implemented similar work to gelation kinetics, but instead, we expressed the activator concentration (wt%) as a function of gelation time (hour) at 200 °F as a constant temperature. Likewise, the activator experienced an exponential relation with gelation time. From Fig. 5, we can see the generated regression module of activator concentration using the Power-Law module.

In addition, as the gelation time goes below 5 hours, the activator concentrations sharply varies from approximately 25% to more than 35%. The developed correlation will be applied to design the nanofluid formulation for field-testing the targeted formation temperature at approximately 200 °F.

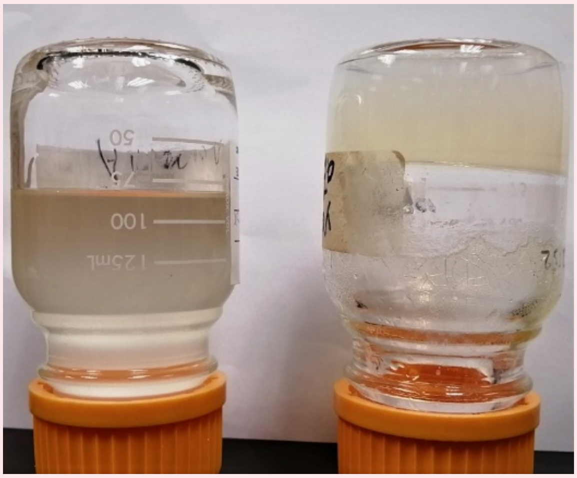
Gel Breakdown Test

In this type of testing, we have looked into the effectiveness of breaker concentration to break down the matured nanosilica gel. The nanosilica fluid was prepared as clarified earlier and then placed in the oven to gel and mature at 210 °F. Several breaker solutions were prepared to select the optimum breaker formulation as a contingent plan for pilot testing. We similarly performed all tests by pouring an equivalent volume of breaker solution to the matured nanosilica gel, which is inside a glass beaker and finally, the beaker is placed in the oven at 210 °F.

The chart in Fig. 6 depicts the summary of experiments in terms of breaker concentrations (wt%) in field water with respect to the nanosilica gel's total breakdown time as observed visually. Between 30% and 50% of the breaker concentrations, we did not notice a significant time change in the gel breakage time. In fact, the gel broke down rapidly and entirely within three hours. The ultimate gel breakdown was reached in almost three days using only 10% of a breaker. Among all lab tests, the gel successfully broke down at an altered time.

Figure 7 is a photo of the nanosilica gel inside two beakers, wherein on the right side we see the matured gel adsorbed to the wall, whereas, on the left side, the beaker contains broken gel after being mixed with a breaker solution.

Fig. 7 A snapshot of two beakers. The left side represents broken gel and the right side represents matured nanosilica gel.



Summary and Conclusions

This work addressed the study of the nanofluid system as a promising water shut-off technology to mitigate undesirable water production from oil wells. The evaluation of nanosilica fluid is emphasized on gelation kinetics. To summarize, the following conclusions were obtained:

- The nanofluid system consists of low impact and eco-friendly materials.
- The system has a low viscosity at ambient conditions, favoring less power requirements for mixing and pumping.
- The temperature, viscosity, and gelation time was correlated based on extensive lab testing.

- We were able to correlate gelation kinetics as a function of activator concentration as denoted by laboratory analysis.
- An optimum breaker concentration was developed based on downhole conditions.

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Key Success Factors for High Power Laser Deployment: Strategy and Execution

Dr. Sameeh I. Batarseh, Dr. Damian P. San-Roman-Alerigi and Abdullah M. Al-Harith

Abstract /

This article presents the strategy and execution that led to the industry's first successful deployment of a high power laser (HPL) in the field. The development encompassed various aspects: administration, technical, lab-to-field transformation, and intensive research.

One of the primary success factors was identifying potential technologies and forecasting their evolution. HPLs were selected for the upstream applications because of their capabilities and successful use in almost every industry, ranging from medical to the military; it attracted the industry due to its unique features, such as precision, reliability, control, and accuracy. HPLs at the early stage (generation) were not applicable for downhole applications due to their relatively lower power levels; however, it has been utilized widely in several applications, such as sensing, measurements, and others.

The objective of this program is to utilize the new generations of higher power lasers in several upstream applications. The program is strategically designed to reduce the risk and increase success. In the initial stage, the work focused on the feasibility and characterization of the intervening physics. The goal was to answer fundamental technical questions, such as "Can lasers penetrate all types of rocks? What are the limitations? What is the effect of the laser on rocks?" The research spanned the last two decades, culminating in the development of the first field prototype of a HPL system.

The work proved that near infrared multiple kilowatt lasers (here on HPLs) could perforate and process any rock type at different conditions, including in situ testing and liquid environments. The experimental plan was designed systematically and divided into phases, starting from fundamentals to advance. Prototype tools were designed, tested, and upscaled for field deployment. All applications can be performed with the same HPL source, only the optical head needs to be changed.

HPL technology is an alternative to conventional methods of subsurface energy extraction, such as perforation, descaling, and drilling. It is cost-effective, compact, versatile, waterless, energy-efficient, and environmentally friendly, thereby enabling sustainable field operations.

Introduction

In the last five decades, global energy demand tripled from 55,000 to 160,000 terawatt hours (TWh). Figure 1 plots this upward trend along the distribution of energy consumption by resource type. Over this period, oil and gas have steadily contributed above 50% to the world's energy mix. In 2021, for example, approximately 57% of the world's energy supply came from oil and gas resources, Fig. 2[1]. If this trend continues, by 2050, the world's energy demand could increase by approximately 47%[2].

Oil and gas resources are expected to provide a significant portion of that energy. The critical challenges for upstream are: (1) increase production from complex reservoirs; (2) eliminate greenhouse gas (GHG) emissions; and (3) reduce energy consumption. The last two are interrelated given the nature of direct and indirect emissions in hydrocarbon life cycle, Fig. 3.

The industry is actively tackling these sustainability challenges by developing advanced technologies and methods, including CO_2 capture and storage, developing methods that limit or eliminate flaring, and establishing comprehensive leak detection and repair programs. Nevertheless, sustainable drilling and extraction from evermore complex reservoirs remain challenging. It is crucial to resolve it; about 4% of global GHG emissions can be attributed to these two activities[5]. High power lasers (HPLs) for upstream applications are a versatile solution to these challenges. Lasers could enable drilling and extraction methods that are energy efficient and environmentally friendly. As a result, the need exists to leverage advances in laser and photonic technologies for applications in the energy industry, focusing on the upstream cycle.

Laser applications across industries have improved efficiency, reduced waste, decreased energy consumption, and therefore eliminated or minimized environmental impacts. In many industrial settings, a single laser can be customized to tackle multiple operations; for example, dentistry uses a single laser to clean, drill, or cut by changing the optics and beam pattern. Lasers can also be configured to attain extreme precision; laser scalpels

Fig. 1 The relative and total energy consumption per source type for the last five decades. Oil and gas resources have contributed above half of the last century's energy mix[1, 3, 4].

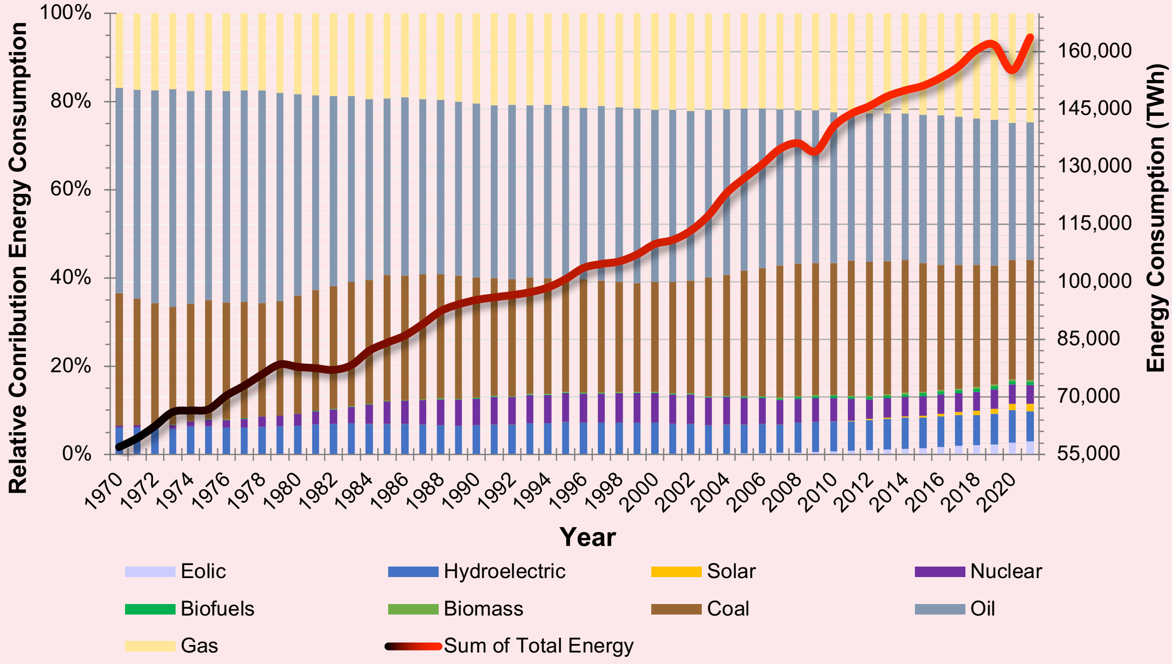


Fig. 2 The distribution of energy consumption by source type: yearly distribution (top left), boxplot distribution cumulative over the last five decades (top right), and distribution in 2021. Over the last 50 years, oil and gas contributed 60% of the world's energy mix. In 2021, the value was 57.64%[1, 3, 4].

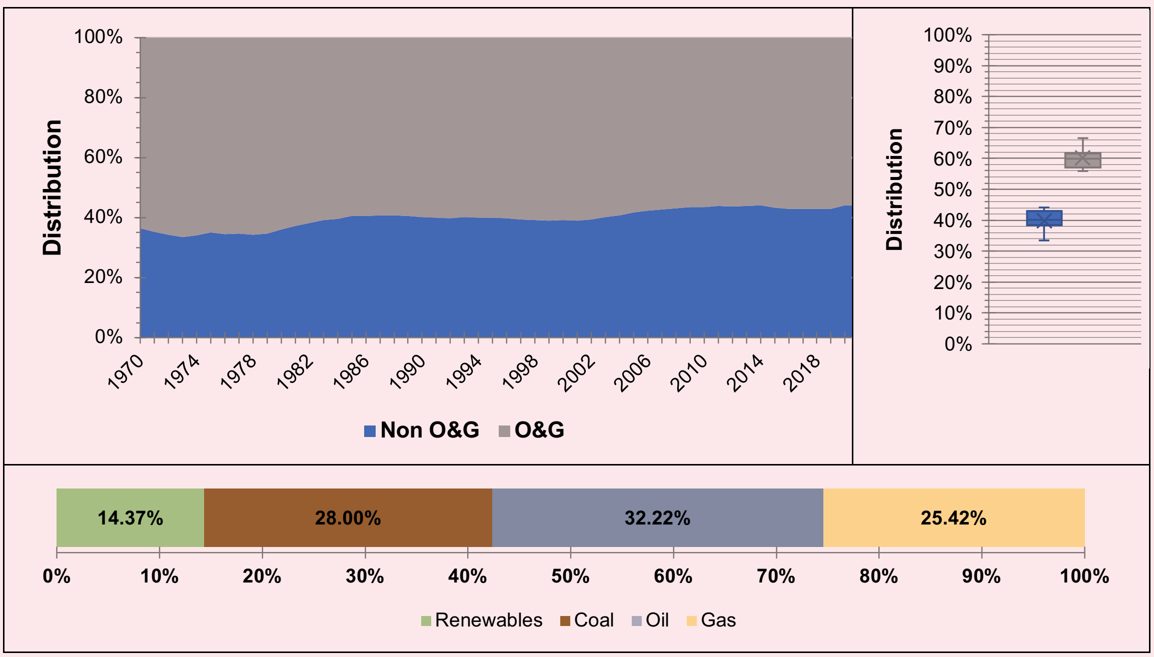
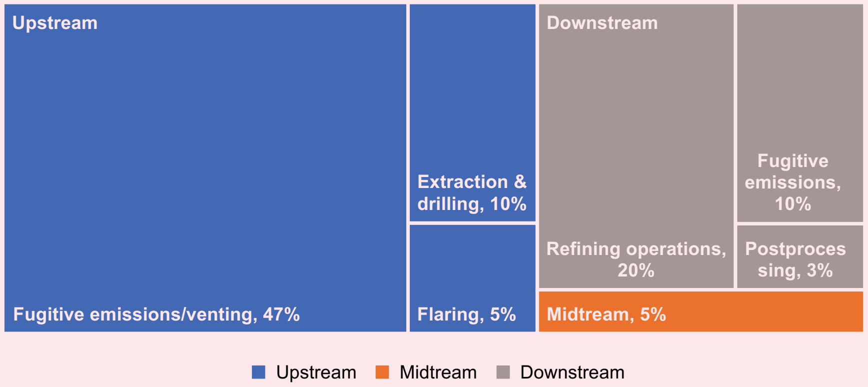


Fig. 3 A tree map of emission attribution across upstream, midstream, and downstream[5].



can cut cancerous cells without harming healthy tissue. Today, lasers underpin various sensors and robotics Upstream, e.g., distributed fiber sensing, emission monitoring, and imaging. Consequently, the application realm has been limited to applications where the maximum power required is below tens of watts.

Extractive processes demand higher energy to cause a phase change in subsurface matter, Table 1. Therefore, drilling and production with lasers require high power sources, typically on the order of tens of kilowatts[6, 7]. The actual power the laser must deliver is determined by the physics of laser-rock interaction, which fundamentally depends on the wavelength of the laser source, the beam's energy distribution, and the electromagnetic properties of the target. Each rock type's reflectance and absorbance properties vary across the electromagnetic spectrum. For example, Fig. 4 plots the absorbance of four rock types at 1,080 nm.

Over the last two decades, experimental tests have demonstrated that near and mid-infrared HPLs with the appropriate optical assembly can be used to descale, perforate, fracture, and drill. The research showed that these lasers could be precisely controlled and oriented to deliver energy in any direction, regardless of the state of stresses in the targeted rocks. This is crucial to production and reservoir management. The ability to control the geometry and orientation of the perforated tunnel could enhance production by eliminating compaction and improving permeability, thereby allowing the flow from pay zones currently bypassed by conventional technologies[9].

These applications demonstrate that lasers are vital contributors to achieving the net zero targets set by the energy industry. The technology enables environmentally friendly and efficient processes that reduce waste, eliminate the use of water and chemicals, and decrease energy consumption. HPL technology is a game changer for our industry. It allows us to harvest the power of light to enable a new generation of Upstream operations. It is a reliable, adaptable, and versatile solution for the future.

Technology Development

Figure 5 depicts the evolution of drilling methods as a function of available energy sources and technology. Early extraction of oil took advantage of gravity using the spring pole method. The industrial revolution brought steam engines that improved drilling efficiency. Technological advances lead to rotary drilling, which is still used today. Recent developments have focused on hardening the cutters of drilling bits, which builds on multidisciplinary breakthroughs in material science and generative design.

The development of the HPL technology for Upstream was designed to take advantage of the evolution of technology to resolve increasingly complex challenges in drilling and extraction. Figure 6 summarizes the program's key elements depicted in a continuous cycle driven as much by business needs as the availability of technology.

Table 1 The energy required to fuse and vaporize four representative rock types[7].

Rock	Latent Heat of Fusion (kJ/g)	Total Heat of Fusion (kJ/cm³)	Latent Heat of Vaporization (kJ/g)	Total Heat of Vaporization (kJ/cm³)
Granite	0.335	4.3 – 4.4	4.8 – 5.3	25.7 – 28.4
Basalt	0.419	4.0 – 4.8	3.9 – 4.2	24.7 – 27.5
Sandstone	0.335	4.5	4.3 – 4.5	18.7 – 19.9
Limestone*	0.498	11.0	6.0 – 6.5	30.9 – 33.4

*Calcium carbonate dissociates in calcium oxide and carbon dioxide at temperatures between 700 °C to 900 °C; therefore, drilling and perforation of this rock type requires approximately 1.78 kJ/g to elicit a calcination process.

Fig. 4 A comparison of reflectance for four various rock samples at 1,080 nm[5].

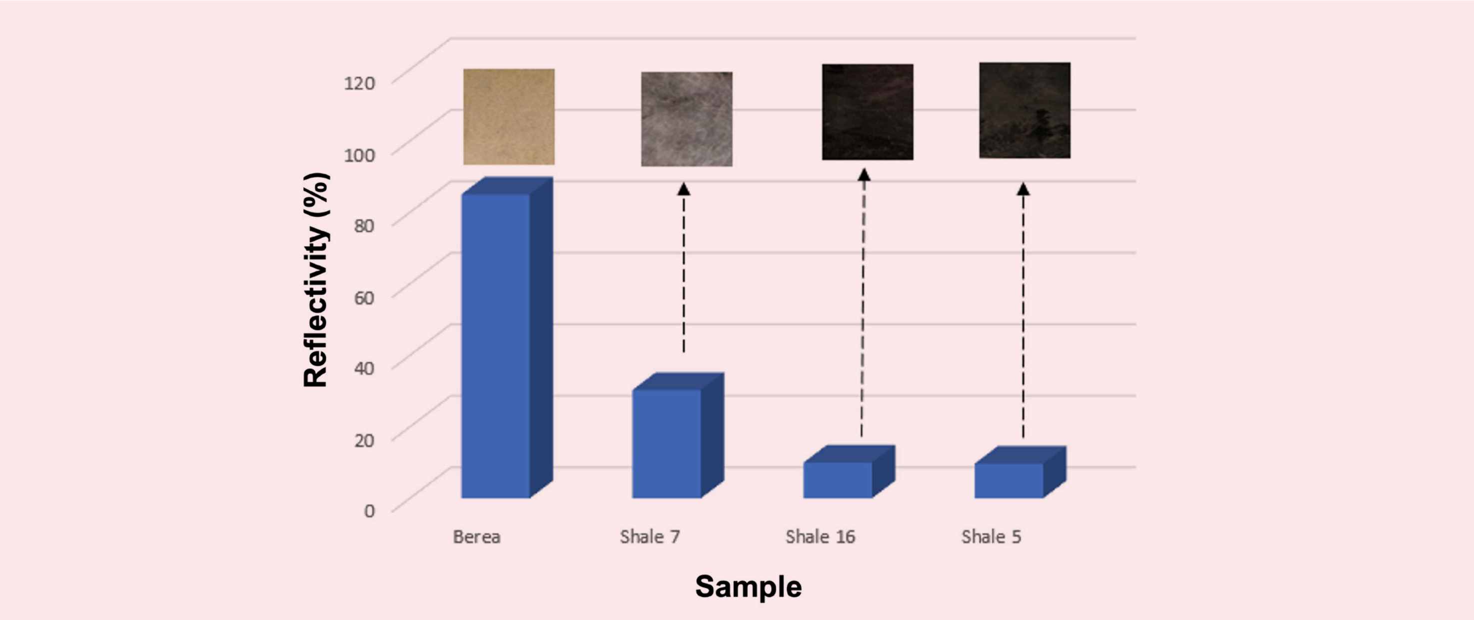


Fig. 5 A timeline of drilling technology evolution.

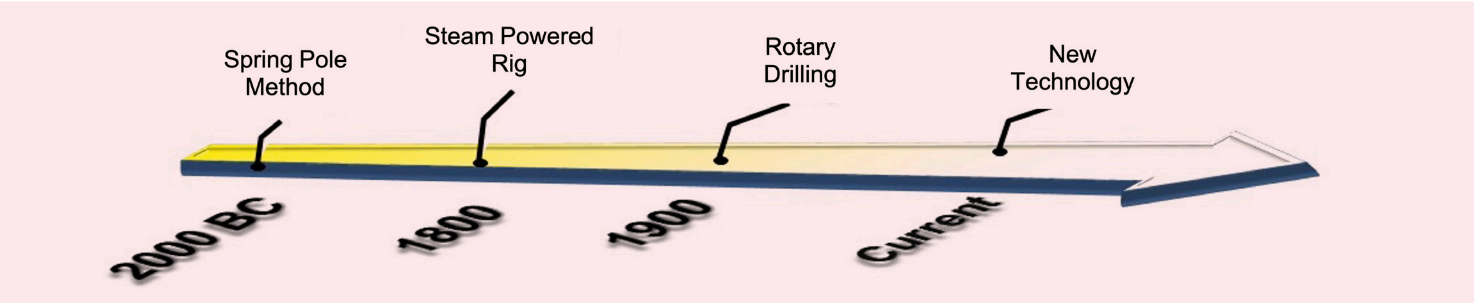


Fig. 6 The key components of the HPL program.

Demand Survey

The demand survey identified areas of opportunity in upstream operations ranging from exploration to well abandonments. This stage also gathered information about existing technologies and practices in each area of opportunity, along with their limitations, environmental impact, and energy requirements. Key challenges selected were: drilling, perforation, heat treatment, and descaling.

Technology Survey

The technology survey reviewed potential solutions for each area of opportunity, including short feasibility tests or meta-analyses focused on identifying the strengths and weaknesses of each method or technology. The study considered several parameters, such as applicability envelope, sustainability impact, efficiency, versatility, and operational and capital cost.

Ideally, the technologies should eliminate formation damage and the use of chemicals or water. Some of the technologies evaluated were: laser, plasma, and microwave, among others.

Technology Selection

The ideal technology offers versatility with high sustainability and low OPEX/CAPEX; i.e., it can efficiently resolve multiple challenges using the same system with minimal environmental impact (if any). HPLs were selected based on these criteria.

Industrial HPLs available today can reach up to 1.2 kW in the visible (450 nm), 100 kW in near infrared (980 nm to 1,100 nm), and 10 kW in mid-infrared (2,000 nm to 10,000 nm). The HPL for Upstream applications must be versatile, i.e., high coupling with any subsurface matter, able to operate in any field condition, energy efficient, i.e., plug efficiency above 30%, and capable of reaching deep targets thousands of meters underground either directly or through fiber optics and require neither chemicals nor water to conduct the operation downhole. The evaluation included commercial and research lasers; while not commercially available, these provide valuable information about the possible applications. Table 2 presents a comparison of different lasers used for evaluation and selection.

When writing this manuscript, fiber-based HPLs in the near infrared (980 nm to 1100 nm) were the best candidate. These lasers are more efficient than other HPLs, with less electric power (20 kW to 25 kW), a smaller footprint (0.5 m^2), and a long lifetime (~50,000 hours); although, these lasers require custom-made fiber to deliver the laser downhole as the laser source sits at the surface.

Research in laser technology and material engineering continuously increases the HPLs' output power and beam quality, expands frequency availability, maximizes efficiency, and reduces the price per kilowatt to single-digit figures. The development of laser technologies for subsurface use must continue to be updated based on this ever-expanding technological landscape, which researchers can capitalize on to expand the technology's applicability envelope at higher efficiency.

Dedicated Feasibility Studies

The feasibility studies delved into laser interaction with subsurface matter — rocks and fluids. The goal was to understand and optimize this interaction considering various settings, including purging gas types, temperature, pressure, and constraining stresses. The primordial focus was on answering, "Can modern HPLs penetrate rocks? If yes, what optimizes the penetration rate for each rock type?"

To answer these questions, selected and representative rock types were selected and exposed to high power fiber lasers. Figure 7 presents different types of rocks ranging in properties and strength from Berea sandstone to granite rocks. The laser powers used were 2 kW, 3 kW, and 6 kW.

Table 2 *A comparison of different commercially available laser systems (courtesy of IPG Photonics Inc.).*

	CO_2	LP Nd:YAG	DP Nd:YAG	HPFL
E/O Efficiency (%)	5 – 10	2 – 3	4 – 6	16 – 20
Electric Power (kW) (no chiller)	~50	~130	~80	20 – 25
Footprint (m^2) (no chiller)	6	5	3	0.5
Water (m^3/hr)	6 – 8	20 – 25	~15	< 2
Maintenance (kWh)	1 – 2	0.5	2 – 3	10 – 15
Pump Replace (kWh)	N/A	0.5 – 1	2.5	> 50

Fig. 7 *The effect of power on the rate of penetration (ft/hr) on Berea Gray sandstone (BG), Limestone (Ls), Shale (Sh), Sandstone reservoir (Sst), Berea Yellow sandstone (BY), and Granite white (GW) and Granite feldspar (GF). (*Extrapolation is used for scaling and illustration only[6].)*

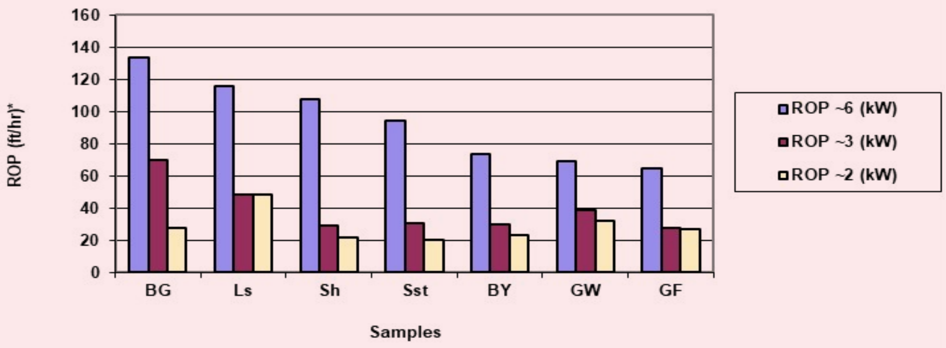


Figure 7 also shows that there are no limitations on the laser penetration, which effectively penetrated all types of rocks, including granite, regardless of their hardness or compressive strength. Besides the ability to penetrate all rock types, the HPL improves the flow properties of the rocks. The porosity and permeability measurements were taken before and after laser exposure. The mechanism of permeability improvement is due to physical and chemical changes.

Physical changes are due to the generation of the high temperature that creates micro- and macrofractures; chemical changes are due to the collapsing of clays and dissociated minerals. For comparison, Table 3 presents the average permeability increase and porosity increase.

Table 3 *The HPL exposure increases permeability and porosity*[10].

Sample	Permeability Increase (%)	Porosity Increase (%)
Berea Yellow	2	57
Berea Gray	22	50
Reservoir Tight Sandstone	171	150
Limestone	33	15
Shale 1	28	700
Shale 2	11	250

Proponents' Engagement

The feasibility studies demonstrated the HPLs' potential for Upstream applications. The next step was prioritizing the applications based on their risk and readiness. The engagement was essential to transforming the lab results into a field prototype. Rock and fluid samples for every application were collected from the field and evaluated in the lab; laser parameters were optimized for each operation to ensure success and reduce risk and uncertainties in the field.

Figure 8 illustrates the optimization process, which maps the effect of different parameters, combing the materials (rocks, scale, and others), laser parameters (power, beam size, exposure time), and environmental conditions (temperature, pressure, wellbore fluids).

Field Ready

The first application selected for field prototyping was descaling because it provided a low risk opportunity to test the laser source, optical tools, and the integrated system in a semi-controlled environment — ambient pressure and temperature. The system consists of a laser generator, chiller, fiber optics, optical connectors, optical head, optomechanical robotics, and assisted gas (nitrogen). The field preparation was done in parallel with the lab optimization. Figure 9 presents the lab and field's parallel efforts to prepare the system for the first field deployment.

The exchange of know-how between field engineers and researchers is critical at this stage. The tool must be designed and optimized within the bounds of the operational envelope, e.g., maximum or minimum reach, temperature, and restrictions, among others. Researchers must assert the repeatability of the laser process from the lab to the integrated prototype. This

Fig. 8 *The optimization process for field applications.*

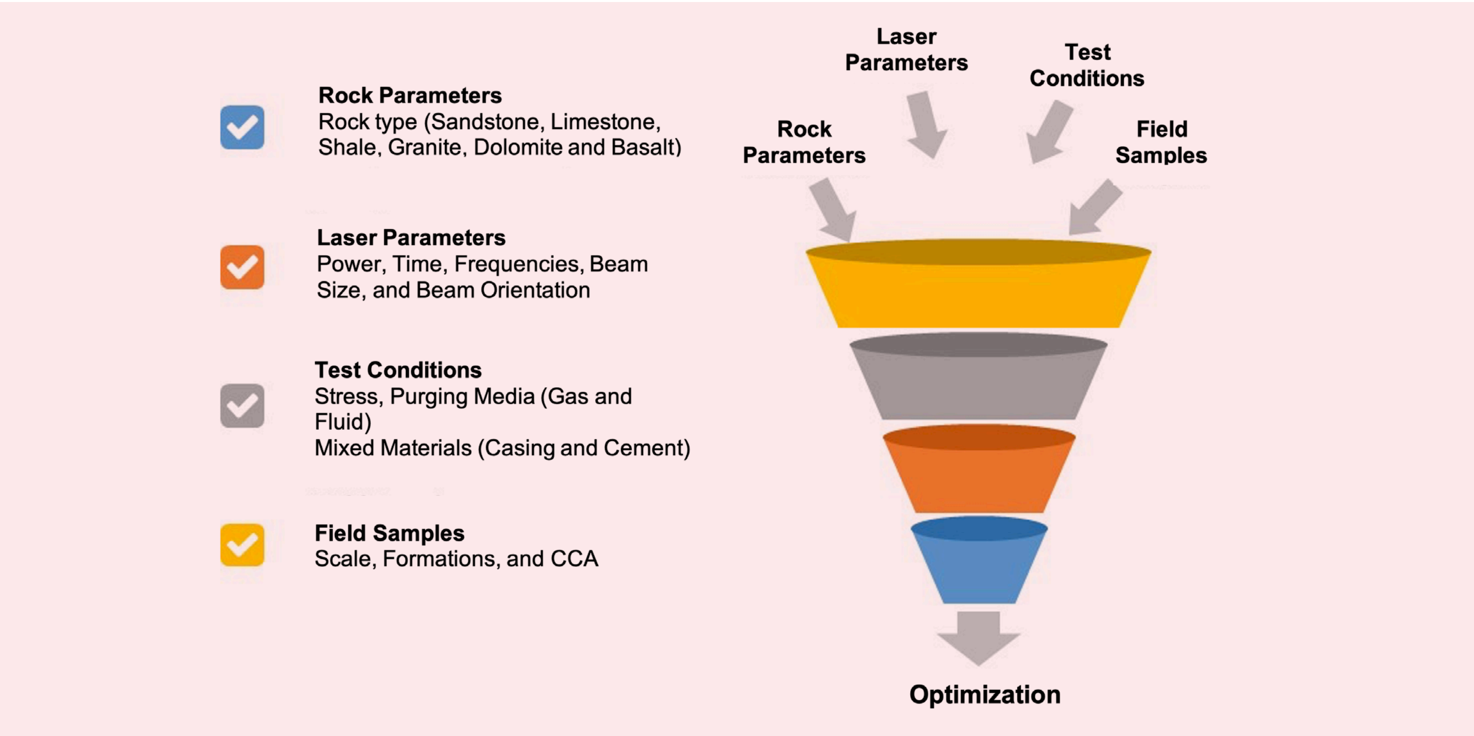
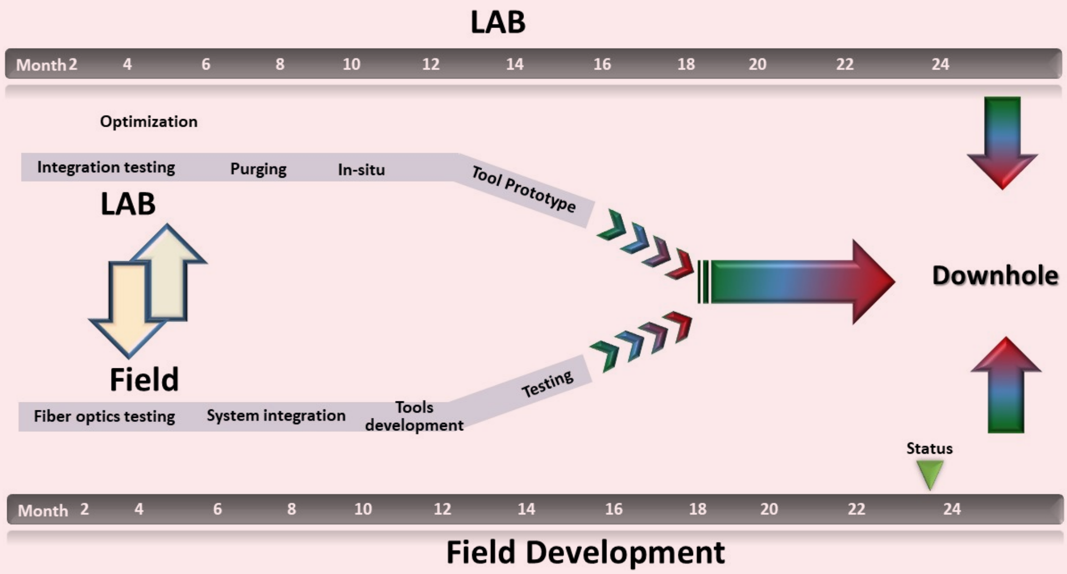


Fig. 9 The lab and field's parallel efforts to prepare the system for the first field deployment.



process is an iterative refinement of engineering design and system integration.

The first worldwide field-tests of a HPL for descaling proved that the technology could thoroughly remove scale without damaging the metal substrate. The laser descaled pipe can be reused, thereby eliminating waste, reducing costs, and saving time. The process is environmentally friendly, waterless, and energy efficient[11]. The success of the first deployment enabled the following application: HPL perforation.

Remarks

The success factors of the program were based on technical and managerial components. These components must align with current challenges and business needs. The first component is the demand survey to identify prevailing challenges in the industry. The second is the technology survey, which reviews and ranks current and future technologies based on their potential applicability, readiness, and sustainability. The next stage is technology selection and feasibility, which evaluates the opportunities and limitations of the selected technology.

In the case of HPLs, an experimental plan was designed to evaluate the performance of the technology in different conditions, starting from ambient to in situ conditions. The feasibility studied laser-rock-fluid interaction and the technologies required to bring the technology to the field. This step answered fundamental questions and demonstrated the viability of HPLs for upstream applications. The next step was to prioritize target applications based on their risk and readiness. In this step, engagement with field engineers is crucial to develop prototypes that befit the field's requirements and ensure a successful deployment.

The first application selected was flow line descaling because it enabled a comprehensive test of the technology in a semi-controlled environment at ambient pressure and temperature. The work tests the integration and performance of the tool.

Team members' selection is critical and is essential to the project's success; key personnel with the right skills and attitude enable the program to progress.

The combination of all these components led to the deployment of the first HPL system for upstream applications.

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Sustainable Chemicals Development for Drilling Fluid Application

Dr. Jothibasu Ramasamy and Dr. Mohammed K. Arfaj

Abstract /

In the oil and gas drilling industry, drilling fluid plays a vital role and is circulated throughout the drilling operation, from spudding to completion. Drilling fluid provides hydrostatic stability to the wellbore. It is also used to cool-down the downhole tools. In addition to these functions, drilling fluid is responsible to carry cuttings to the surface, provide lubricity, and stabilize shale formation.

There are a variety of chemicals added to drilling fluid to provide properties, i.e., viscosity, density, emulsion stability, lubricity, and fluid loss control. Development of drilling fluid chemicals that are sustainable and benign to the environment to provide the aforementioned properties is a significant step toward achieving sustainability and reducing the carbon footprint, in addition to being suitable for drilling across aquifers and offshore environments. We have studied the applicability of used cooking oil to obtain fatty acid and their derivatives and evaluated its performance as emulsifiers and lubricants for drilling fluid applications.

Introduction

The oil and gas industry, worldwide, has a long-standing initiative in the progress of environmentally benign solutions in the exploration and production of hydrocarbon resources to tackle the impact toward marine and terrestrial species. Investigating the challenges encountered while drilling — and troubleshooting these challenges — highlights the significance of answering environmental challenges as one of the major issues, in addition to the technical and logistic challenges in a safe drilling operation.

It is vital to address the factors associated with regular additives concerning environmental and marine life by conducting developmental research applicable to oil and gas industry operations. There have been measures taken and followed by the oil and gas industry to reduce the impact of traditional chemicals on the environment and carbon footprint as seen from the growing interest to introduce more green technologies. Along this line of research, there have been a few articles reporting on the importance of eco-friendly additives in designing high performance drilling and completion fluids, loss control slurry, fracturing and stimulation fluids, etc.[1-3].

Advantages of green chemicals as additives for drilling fluids over the traditional chemicals have been shown to be beneficial as reported[4, 5]. The practice of using eco-friendly chemicals has been increased in offshore operations[6-8]. In the U.S. market, approximately 10% of green lubricants are introduced annually as compared to conventional lubricants, which is approximately 2%[4, 5].

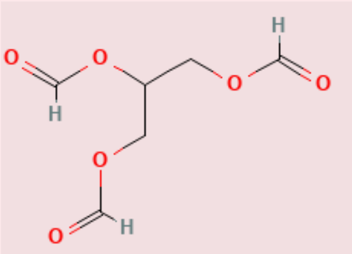
Many drilling fluid chemicals are derived from fatty acids and their derivatives as fatty acids provide eco-friendly and bio-degradable properties. Fatty acid-based products are used in drilling fluid lubricants to reduce torque and drag for water-based mud (WBM). In case of oil-based mud (OBM) systems, fatty acid derived products are used as emulsifiers, wetting agents, and rheology modifiers. Tall oil fatty acid is the primary source of fatty acids and their derivatives. Consequently, depending solely on tall oil fatty acid for obtaining fatty acid and their derivatives has limitations, due to supply constraint. Moreover, there are several other industries such as food, cosmetics, paints, drugs, etc., that use fatty acid and their derivatives. This causes an increased demand and drives the cost higher for fatty acid and their derivatives.

In drilling, the major budget is allocated to drilling fluid chemicals. Therefore, any small improvement to bring the cost down of chemicals will result in a significant cost saving. Therefore, finding an alternative source to develop fatty acid and their derivatives is essential to have eco-friendly and sustainable chemicals to include in drilling fluid, while providing a lower cost.

Cooking or vegetable oil contains triglycerides, which are a fatty acid ester of glycerol. Figure 1 shows the molecular structure of triglyceride. Therefore, triglycerides could be a potential source for developing fatty acids and their derivatives. Fresh cooking oil is not an attractive source due to cost. On the other hand, used cooking oil provides a perpetual and sustainable source of raw material for various types of eco-friendly additives development.

Depending on the kind of plant, fruit, or seed from which the oil is produced, vegetable oil may contain a mixture of fatty acids, such as saturated, monounsaturated, polyunsaturated, omega 3, omega 6, or omega 9.

Fig. 1 The molecular structure of triglycerides present in vegetable/cooking oil.



Common oils used in the cooking industry are olive oil, palm oil, sunflower oil, corn oil, and peanut oil, which contain most of the fatty acid types mentioned. The fatty acids obtained are environment friendly, bio-degradable and nontoxic. Owing to the benefits that fatty acid and their derivatives offer, such as technical performance, economic and environmental benefits, we have carried out several research projects to develop a number of additives for oil and gas field applications.

Table 1 shows the commonly used cooking oils and the fatty acid content present in the oils.

In this article, we will describe the method of converting used cooking oil into a mixture of fatty acids useful for applications in drilling fluids. Our studies include a lubricant for WBM to reduce torque and drag by minimizing the friction between the wellbore and downhole tools, and for OBM, we used the fatty acids as a primary emulsifier to provide emulsion stability for the invert emulsion. A comparison study has been conducted to benchmark the fatty acid mixture (FAM) with commercial counterparts.

Conversion of Used Cooking Oil to Fatty Acids

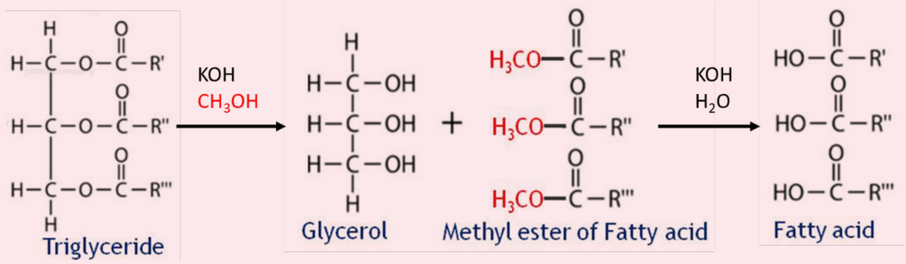
The abundant availability of used cooking oil from restaurants and other food industry makes it attractive as a sustainable raw material. Industries, such as the makers of soap and detergent, recycle the used cooking oil as a raw material. Therefore, collection mechanism and logistics of used cooking oil is well established in most countries. Therefore, instead of fresh vegetable oil, used cooking oil was used for our study as a raw material to chemically produce fatty acids. A simple cleanup process such as filtration and removal of food and other debris needs to be performed before taking it for chemical treatment.

Figure 2 shows the chemical conversion of triglyceride, which is a used cooking oil to methyl ester of fatty acid and the corresponding fatty acid. Base hydrolysis of triglyceride with potassium hydroxide in methanol yielded glycerol and fatty acid methyl ester. Glycerol is removed as a byproduct. The fatty acid methyl ester is taken for further reaction with potassium hydroxide in water. This reaction is for conversion of methyl ester of fatty acids to their corresponding fatty acids. This process provides a mixture of different fatty acids such as saturated (palmitic acid), monounsaturated (oleic acid) and polyunsaturated (linoleic acid) fatty acids, as confirmed by high performance liquid

Table 1 The commonly used cooking oils and the fatty acid composition of each.

Type	Saturated Fatty Acids	Monounsaturated Fatty Acids		Polyunsaturated Fatty Acid		
		Total Mono	Oleic Acid (ω-9)	Total Poly	Linolenic Acid (ω-3)	Linoleic Acid (ω-6)
Canola Oil	7.4	63.3	61.8	28.1	9.1	18.6
Coconut Oil	82.5	6.3	6	1.7	—	—
Corn Oil	12.9	27.6	27.3	54.7	1	58
Cottonseed Oil	25.9	17.8	19	51.9	1	54
Linseed Oil	9.0	18.4	18	67.8	53	13
Extra-Virgin Olive Oil	13.8	73.0	71.3	10.5	0.7	9.8
Palm Oil	13.8	73.0	71.3	10.5	0.7	9.8
Peanut Oil	16.2	57.1	55.4	19.9	0.318	19.6
Rice Bran Oil	25	38.4	38.4	36.6	2.2	34.4
Sesame Oil	14.2	39.7	39.3	41.7	0.3	41.3
Soybean Oil	15.6	22.8	22.6	57.7	7	51
Sunflower Oil	8.99	63.4	62.9	20.7	0.16	20.5
Walnut Oil	8.99	63.4	62.9	20.7	0.16	20.5
Hemp Seed Oil	7.0	9.0	9.0	82.0	22.0	54.0

Fig. 2 *The synthesis of fatty acids from triglycerides.*



chromatography (HPLC) and mass spectrometry.

Triglyceride can also be treated with water and potassium hydroxide to convert directly to fatty acids. Subsequently, the cleanup procedure is tedious and not a straightforward process to obtain fatty acids. Therefore, we followed the two step synthetic process to obtain fatty acids. The obtained fatty acids are taken for further studies and evaluation for drilling fluid applications.

Results and Discussion

As previously mentioned, fatty acids and their derivatives are used in drilling fluids for various applications such as emulsifier for invert emulsion OBM, rheology modifier for OBM, corrosion inhibitor for WBM, and lubricant for WBM. In our study, we tested the fatty acids obtained from the reaction for use as a primary emulsifier and for lubricant applications.

The details of the experiments and results are discussed next. Conventional mud additives are used to formulate invert emulsion OBM and WBM systems to confirm the newly developed fatty acids are compatible with other regular mud additives.

FAM as Primary Emulsifier

The FAM obtained from the reaction, Fig. 3, is tested for its application as a primary emulsifier to formulate invert-emulsion OBM. Table 2 lists the invert-emulsion mud formulated using FAM, and a commercial chemical as the primary emulsifier. Compared to the commercial emulsifier, the newly developed emulsifier is less viscous and there is no need for dilution using other hydrocarbon-based solvents as in the case of commercial emulsifiers. For the initial screening, 12 ml of primary emulsifier loading was used. Regular mud property measurements, including rheological property, API and high-pressure, high temperature (HPHT) filtration control properties have been carried out to compare the properties of these two mud systems. These tests were carried out after hot rolling both mud systems at 300 °F and 500 psi for 16 hours. The experimental results are discussed next.

Both formulations exhibited very good and similar rheological properties such as yield point and gel strength. Figure 4 shows

Fig. 3 *Fatty acid mixture (FAM).*

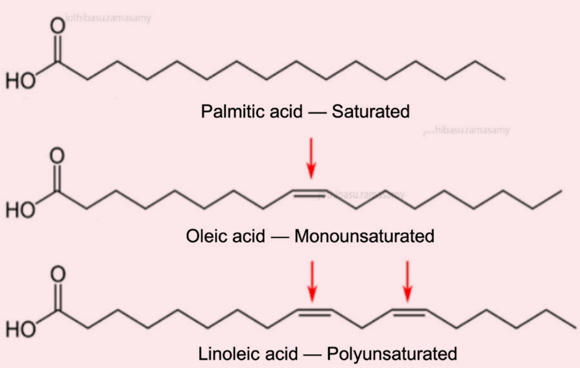
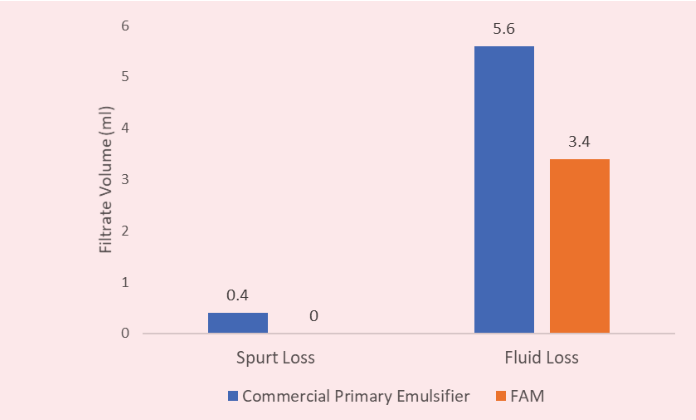


Table 2 *A comparison of the emulsifier performance.*

Mud System	Formulation Using Commercial Emulsifier	Formulation Using FAM
Safra oil (ml)	218	218
Commercial primary emulsifier (ml)	12	0
FAM (ml)	0	12
Commercial secondary emulsifier (ml)	4	4
Lime (g)	6	6
Organophilic clay (g)	4	4
Organophilic lignite (g)	6	6
Brine (61 g $CaCl_2$ in 85 cc water) (ml)	85	85
Barite (g)	161	161
Mud properties after hot rolling for 16 hours at 300 °F and 500 psi		
Plastic viscosity	23	24
Yield point	9	11
10 sec gel strength	5	5
10 min gel strength	11	7

Fig. 4 *The HPHT spurt and fluid loss of the commercial emulsifier and the FAM formulation.*



the HPHT spurt and fluid loss behavior of the OBM systems in the presence of the commercial emulsifier and the newly developed eco-friendly emulsifier FAM. Data from the HPHT filtration control experiments conducted at 300 °F and 500 psi clearly show better performance of the FAM than the commercial emulsifier. The new emulsifier created a tighter and highly effective emulsion that allowed better control of the fluid loss behavior of the FAM containing mud. More importantly, the filtrates obtained from the HPHT filtration control experiments show no separation even after 12 hours. This proves the creation of a stable emulsion by primary emulsifiers even at HPHT conditions. After confirming the FAM is providing good emulsion stability, screening of the FAM has been conducted, Table 3.

Figure 5 shows the API spurt and fluid loss behavior of formulations containing different concentrations of FAM. The data indicates that 6 ml or more should be used to achieve nearly zero API fluid loss and virtually no spurt loss. It is recommended to use a concentration of 6 ml to 12 ml, depending on various application scenarios.

Figure 6 shows the results of the filtrate obtained by the HPHT filtration experiment conducted using 0 ppb, 4 ppb, and 6 ppb emulsifier concentration. Filtrate from the mud containing 0 ppb and 4 ppb eco-friendly emulsifier shows water and oil phase separation. The filtrate from the formulation containing 6 ml of the eco-emulsifier showed no phase separation due to the formation of a tight and effective emulsion. This data clearly indicates that a concentration range of 6 ml to 12 ml of the new emulsifier is sufficient enough to create a technically effective OBM system.

It is demonstrated from the mentioned experimental details and the results discussed, that the newly developed FAM is performing as good as the routinely used commercial emulsifier. From the data obtained, it is recommended to use 6 ml to 12 ml of FAM for formulating invert-emulsion OBMs for various applications.

FAM as Lubricant for WBM Systems

The lubricating potential of the drilling mud is one of the key factors for efficient drilling operation in deviated, horizontal, extended reach, multilateral, and also vertical wells with high dog-leg severity. WBMs inherently have poor lubricating potential. To make the mud lubricious, various chemicals are added to WBM. The chemicals used as lubricating additives are based on fatty acid derivatives and petrochemicals. Some of the lubricants are suitable to use across aquifers and in an offshore environment[7, 8].

The FAM developed from used cooking oil has also been studied for its potential as a lubricant for WBM. The lubricating

Table 3 *The concentration screening of the FAM.*

Mud System				
Safra oil (ml)	218	218	218	218
FAM (ml)	12	6	4	0
Commercial Secondary Emulsifier (ml)	4	4	4	4
Lime (g)	6	6	6	6
Organophilic clay (g)	4	4	4	4
Organophilic lignite (g)	6	6	6	6
Brine (61 g $CaCl_2$ in 85 cc water) (ml)	85	85	85	85
Barite (g)	161	161	161	161
Mud properties after hot rolling for 16 hours at 300 °F and 500 psi				
Plastic viscosity	24	35	34	30
Yield point	11	12	17	30
10 sec gel strength	5	9	9	7
10 min gel strength	7	10	10	9

Fig. 5 *The HPHT spurt and fluid loss for the FAM concentration screening.*

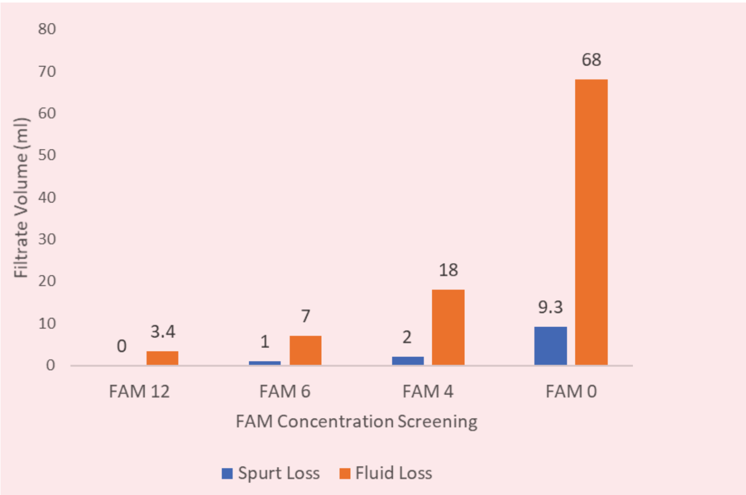
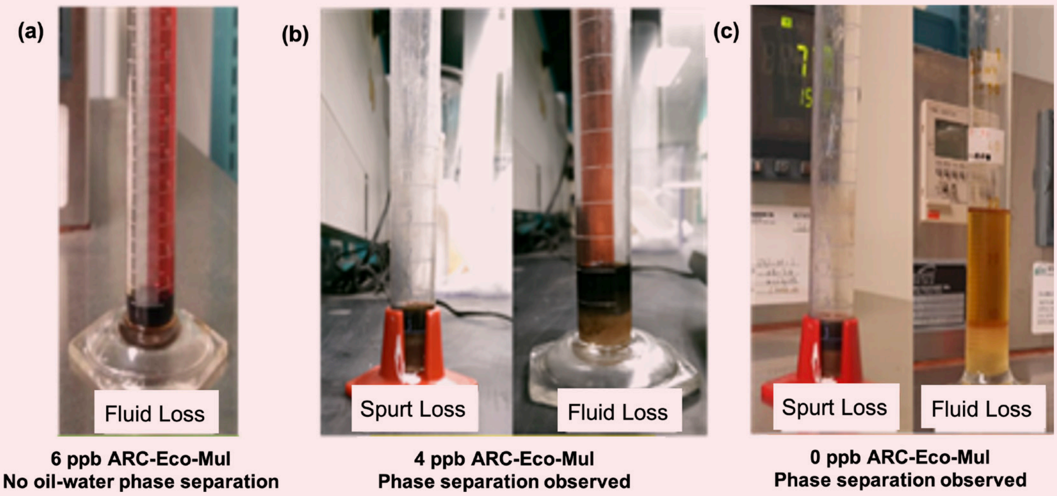


Fig. 6 *The filtrate obtained from HPHT fluid loss experiments; (a) 6 ppb, (b) 4 ppb, and (c) 0 ppb.*



potential of FAM was evaluated using the industry standard lubricity testing device. A widely used commercial lubricant was also evaluated for its lubricating potential for comparison of performance with the FAM. Four different WBM systems, routinely used, have been used for this study, which includes monovalent, divalent, low solid non-dispersed (LSND), and clay-based mud systems. Table 4 lists the mud formulations.

The experiment involves the measurement of the coefficient of friction (COF) for different fluids. As a control, COF measurements were taken for mud samples without lubricant as a benchmark for the lubricant evaluation.

Figure 7 shows the COF values for the measurement of mud without a lubricant, mud with an additional 3% commercial lubricant, and mud with an additional 1% FAM. It is evident from the data provided in Fig. 7 that the newly developed lubricant FAM provides excellent lubricity with more than 50% reduction in COF as compared to the COF values for muds without a lubricant. Moreover, even with 1% loading, the FAM has better or comparable lubricating performance as compared to the COF reduction by adding 3% of a commercial equivalent. It demonstrates the superior performance of FAM as a lubricant for WBM systems.

Conclusions

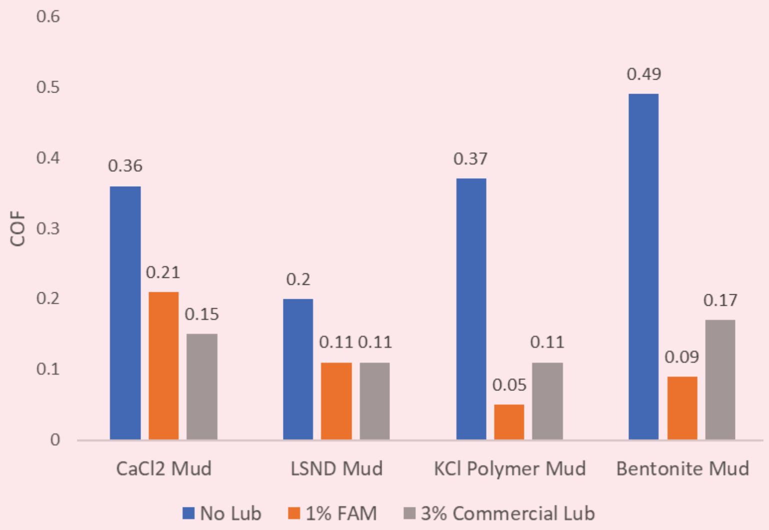
We have shown the development of eco-friendly drilling fluid additives from waste vegetable oil by a simple chemical process. FAMs derived from waste vegetable oil have been used as a primary emulsifier for invert-emulsion OBM. From the various experiments that were carried out, it is evident that the fatty acid from waste vegetable oil has a very good property as an emulsifier, and comparable properties with a commercial emulsifier.

Similarly, we have also shown the superior lubricating property of FAM that outperforms commercial lubricant. It is evident from our studies that products derived from waste vegetable oil can in fact be used for drilling fluid applications. Development of products for other applications such as cementing as well as further fictionalization of fatty acid is under way in our laboratory.

Table 4 *The mud formulations used for the lubricity study.*

$CaCl_2$ Mud		**LSND Mud**	
Water (ml)	320	Water (ml)	332
Soda Ash (g)	0.25	Soda Ash (g)	0.3
Bentonite (g)	5	Bentonite (g)	6
PAC LV (g)	3	PAC L (g)	3
XC Polymer (g)	1	XC Polymer (g)	1
KCl (g)	20	KCl (g)	20
Rev Dust (g)	25	Soltex (g)	3
$CaCl_2$ (g)	20	Sodium Sulfite (g)	1
pH	9.5	pH	9.5
KCl Polymer Mud		**Bentonite Mud**	
Water (ml)	321	Water (ml)	345
Soda Ash (g)	0.25	Soda Ash (g)	0.25
Bentonite (g)	5	Bentonite (g)	5
PAC LV (g)	3	pH	9.5
XC Polymer (g)	1		
KCl (g)	40		
pH	9.5		

Fig. 7 The COF values for various mud systems.



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Utilization of Innovative Resin Cement Blend to Enhance Wellbore Integrity

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Abstract /

A major challenge that is occasionally being faced during the well's life cycle is the pressure buildup between the cemented casing annuli, also known as sustained casing pressure. Compromise of cement sheath integrity is one of the primary reasons for such a pressure buildup. This challenge prompted the development of an isolation material that should enhance the mechanical properties of cement. The resin cement blend system can be regarded as a novel technology to assure long-term zonal isolation.

This article presents the lab testing and application of the resin cement system, where potential high-pressure influx was expected across a water-bearing formation. The resin cement system was designed to be placed as a tail slurry to provide enhanced mechanical properties in comparison to a conventional slurry. The combined mixture of resin and cement slurry provided all the necessary properties of the desired product. The slurry was batch mixed to ensure the homogeneity of the resin cement slurry mixture. The cement treatment was performed as designed and met all zonal isolation objectives.

Engineered solutions ultimately deliver the optimal asset value of the reservoir. During the last few decades, several laboratory investigations and field studies have been conducted to find solutions to the problem of sustained casing pressure, which appears after primary or remedial cement jobs. Almost all of these studies unanimously conclude that the conventional cement does not always endure the mechanical stresses imposed by the wellbore conditions, and it often falls short in providing long-term isolation beyond the production life of the well.

When the resin is introduced into a cement slurry, it forms a dense, highly cross-linked matrix. The extent of the cross-linking reaction is governed primarily by volume, temperature, and time. The distribution of resin throughout the slurry provides a shock absorbing tendency to the particulates of the cement. This feature increases the ductility and the resilience to withstand stress from load-inducing events throughout the life of the well. The resin cement's increased compressive strength, ductility, and enhanced shear bond strength help to provide a dependable barrier that would help prevent future sustained casing pressure.

Introduction

Cementing should be done in a way to provide zonal isolation, protect and support the casing, resist attack from the formation fluids, and prevent the fluids' migration. When we design cementing formulations, we design it to ensure good wellbore integrity through the entire service lifetime of a well[1]. Several causes can lead to the loss of the zonal isolation with time during the life cycle of a well, such as: gas migration, loss of cement bond log, extreme downhole temperature, pressure changes, and stimulation treatment[2].

A major challenge that is occasionally faced during the well's life cycle is the pressure buildup between the cemented casing annuli, also known as sustained casing pressure. A compromise of cement sheath integrity is one of the primary reasons for such a pressure buildup. Another challenge that we may face are potential well control incidents at the top of liners (TOL) that may take place after cement placement. Typically, liners are run and cemented. After a liner hanger is set, reverse circulation takes place. Positive and negative tests might be conducted to ensure the integrity at the TOL position. Then, a clean out run is conducted, and well fluids are displaced to lower fluid density to conduct a flow check after displacement. Potential well control incidents could be indicated from the previous flow tests (positive test, negative test, or flow check test)[3].

Cement shrinkage is another factor that can lead to potential well control incidents, or compromise in the wellbore integrity, especially when changing the fluids' densities or performing pressure testing. Expansion additives are usually added to overcome this shrinkage; however, the applied stresses' effect on the casing or liner might not be mitigated by using only expansion additives.

Another factor we need to pay attention to is the selection of the suitable cement density to mitigate losses induced by cementing. When cementing weak formations, we need to design cement slurry density to be lower than typical conventional cements to reduce hydrostatic pressure and mitigate breaking down the formation. High density cement can fall back because the formation did not support the hydrostatic load, which may result in un-cemented casing being exposed to sulfide containing water, resulting in potential corrosion. Using multistage tools is another option to reduce hydrostatic pressure by reducing the depth of cemented intervals. Consequently, stage tools may be considered as weak points in the casing and are not good for a long-term seal.

Water extender additives, such as bentonite and sodium silicate, can be used; however, water extender cements are limited to approximately 85 pcf in density. Foam cementing can result in low density slurries. Hollow microspheres (ceramic or glass) can reduce cement density due to their low specific gravities (SG). We can formulate down to 70 pcf cements with acceptable properties by using low SG additives.

There are several different methods to utilize low SG additives to formulate low density cement. We can use a mixture of any of the following additives, e.g., coarse or fine cement particles, fly ash, fumed silica, hollow microspheres, aluminum metal powders, and sodium sulfate[4].

For proper wellbore integrity, we need to pay attention to the mechanical properties of cement, such as the compressive strength, Young's modulus, Poisson's ratio, and the tensile strength. Numerous stresses or forces may influence the cement's mechanical properties[5]. The most important mechanical properties to consider to improve cement resistance against stresses is Young's modulus. Therefore, targeting low Young's modulus in cement formulations is very important to increase the cement flexibility, enhance the resistance against pressure and temperature cycling, absorb applied stresses, and prevent cement cracks[6].

A new self-healing durable cement with reduced Young's modulus was designed, utilizing novel components. When exposed to oil, the developed self-healing cement also provides swelling and sealing capacity of the cement. In potential leaks, hydrocarbon fluids migrating through cement cracks will activate the expanding and swelling mechanism[2, 7].

Al-Yami et al. (2017)[8] developed a high density cement slurry with polymer resins to improve mechanical properties of cement and provide resistance against hydrocarbons, acids, and salts. This developed solution at high density is an ideal system for wells that have harsh environments, such as carbon dioxide (CO_2) or hydrogen sulfide (H_2S), and are exposed to high stress loads throughout the lifetime of the well. The objectives of this study are to show new systems at different densities utilizing epoxy resin as an additive and to demonstrate the value added in terms of improved mechanical properties and bonding.

The resin we utilized in this study is diglycidylether of bisphenol-F. It is a linear epoxy resin formed by reacting bisphenol-F with a suitable amount of epichlorohydrin and hydroxide; amines are used as curing agents for epoxy resins. The curing mechanism is a step-growth polymerization. The curing is shown first by an increase in viscosity and then hardening. The final product properties in terms of compressive strength and viscosity also are affected by the type and concentration of the amine. Aliphatic amines produce a more flexible type of epoxy resin compared to an aromatic amines curing agent. Aromatic amines will produce a stronger, harder epoxy resin[9].

Experimental Study

Cement Slurry Preparation and Testing

The cement slurry is formulated and mixed with a maximum speed of 12,000 rpm for 15 seconds and then at 4,000 rpm for 35 seconds. To condition the cement slurry, we use an atmospheric consistometer. A Fann Model-35 viscometer is used to measure rheological properties. Thickening time tests are done by pouring the prepared slurry into an API standard high-pressure, high temperature consistometer and then performing the tests at the desired temperature and pressure[10, 11].

Fluid loss measurements (dynamic and static) were performed on the prepared cement slurry. Dynamic fluid loss can affect the rheology and the thickening time of the cement slurries. Static fluid loss can result in a reduction in the cement slurry and allowance of formation fluids to enter the cement slurry.

Separation of water is observed when a cement slurry is allowed to stand for a period before it sets. To determine the extent of water separation, a free water test is performed. The test is done by allowing the cement slurry to stand in a 250 ml graduated cylinder for a period of 2 hours. A settling test can be performed by density measurements at different sections of a cured cement sample, when cured in a cylindrical shaped cell having a length of 12" and diameter of 1.4"[10].

A curing chamber was used to cure the cement slurry at the desired temperature and pressure. The cement slurry is poured in a cylindrical cell and lowered into a curing chamber. While maintaining the pressures and temperatures, the cement slurry is cured up to 30 days. At the end of the curing period, the pressure and temperature were reduced to ambient conditions and the test specimens were subsequently removed from the curing chamber to be tested for mechanical properties.

Mechanical Properties Testing

Single-stage triaxial tests were performed on set cement samples after curing for 30 days. The samples had a length of 2.997" to 3.020" and a diameter between 1.490" and 1.510". Static and dynamic measurements were performed using ultrasonic and shear velocities. The mechanical properties obtained were Young's modulus, Poisson's ratio, and peak strength[8].

Shear Bond Testing

The force required to move a pipe through a column of set cement is defined as shear bond. The shear bond test includes filling an annulus between two pieces of pipe with a cement slurry and letting it set in the curing chamber. Figure 1 is an image of the shear bond mold used for the shear bond test.

After the cement composition sets, the outer pipe is supported on the bottom plate of a load press while force is applied to the center pipe by the load press. The load indication on the press increases until the bond breaks between the pipe and the cement composition. This loading force is converted to a force per unit area and is called the shear bond strength.

Results and Discussion

Resin cement formulations at 135 pcf, Tables 1 and 2 and Figs. 2 and 3, and at 125 pcf, Tables 3 and 4 and Figs. 4 and 5, were prepared and tested for density, rheology, compressive strength development, free water, and thickening time tests. Approximately 8% resin (by volume of slurry) was added into the slurry to achieve the final product density. The compressive strength of the resin cement system showed acceptable development at 500

Fig. 1 An image of the shear bond mold used for the shear bond test.

*Table 1 The formulation of the resin cement system at 135 pcf. *BWOC is by weight of cement.*

Component	Concentration
Cement	Base
Water	4.802 gal/sack
Antifoam	0.01 gal/sack
Stability enhancer	0.30% BWOC*
Fluid loss	0.25% BWOC
Dispersant	0.40% BWOC
Retarder	0.27% BWOC
Epoxy resin	8.97% BWOC
Curing agent	0.31% BWOC

psi in a short time. A good compressive strength development is important to resume drilling operations such as drilling casing shoe or TOL and pressure testing.

Conventional cement slurries at 85 pcf are shown with its properties, Tables 5 and 6. A water extender is used, such as sodium silicate or bentonite, to reach down to such low density. This type of cement is known to be a filler type of cement, which is used in upper casing sections. It is not targeted to provide good wellbore integrity and it is known to have low compressive strength.

Table 7 shows the properties of the resin cement system at 85 pcf. Of course, resin by itself reduced the density, which allows us to use a reduced amount of water extenders to improve cement properties and enhance the wellbore integrity. Another

Table 2 The properties of the resin cement system at 135 pcf.

Property	Value
Density	135 pcf
Slurry yield	1.56 ft^3/sack
Water requirement	4.8 gal/sack
Total mix fluid	5.8 gal/sack
Thickening time	5.48 hours
300 rpm	264
200 rpm	195
100 rpm	116
60 rpm	81
30 rpm	50
6 rpm	19
3 rpm	15
Free fluid	0%
Fluid loss	34 ml/30 minutes

formulation utilizing resin cement was designed and tested at a density of 75 pcf, Table 8. At such a low density, we need to introduce low SG solids to reduce the density and produce acceptable properties. We cannot depend on a water extender to design good cement properties at such a low density. If we use a water extender to formulate the cement slurry at 75 pcf, we will end up with phase separation and cement settling. Hollow glass spheres were used to formulate the 75 pcf cement.

Conventional cements have values of static Young's modulus range between 3 million psi and 3.5 million psi[11], which indicates that the cement is too rigid to resist any type of pressure or temperature cycling. Pressure testing the TOL may result in potential well control incidents due to potential cement leaks. Potential casing-casing leaks may occur due to the changing fluids densities when drilling from one section to another, or due to pressure tests. All of this is due to the nature of the cement.

Cement is crystalline in nature, which makes it strong and rigid. To overcome this issue, we need to reduce the crystalline phase and increase the amorphous phase content by adding chemicals or additives, such as elastomers, fibers, or polymers, such as the polymeric epoxy resins. Looking at the long-term testing or the mechanical properties testing results, Fig. 6, it is quite evident that the static Young's modulus is lower for the resin cement system as compared to conventional cement at a density of 135 pcf.

These lower values are good indicators for the cement to resist pressure and temperature cycling. For the 85 pcf, the main reason for the reduction in Young's modulus value was the reduction in density. We were not able to measure the mechanical properties of the conventional cement at 75 pcf due to improper cylinder dimensions. Compressive strength for the 85 pcf resin cement system was higher than the conventional cement using a water

Fig. 2 The thickening time test for the resin cement system at 135 pcf.

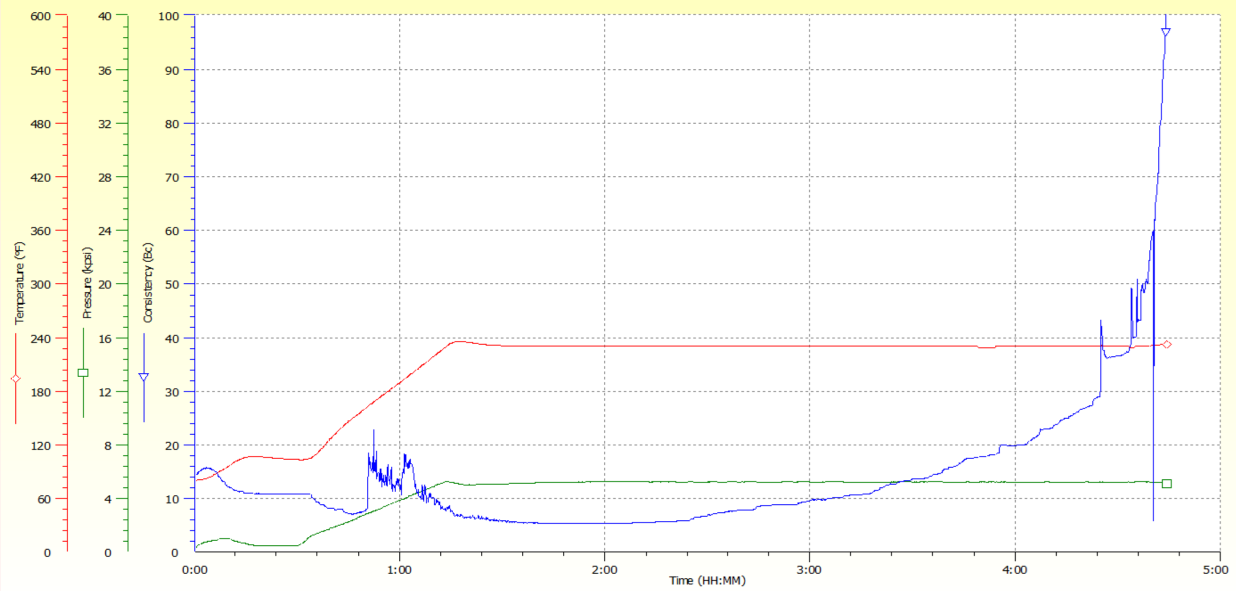
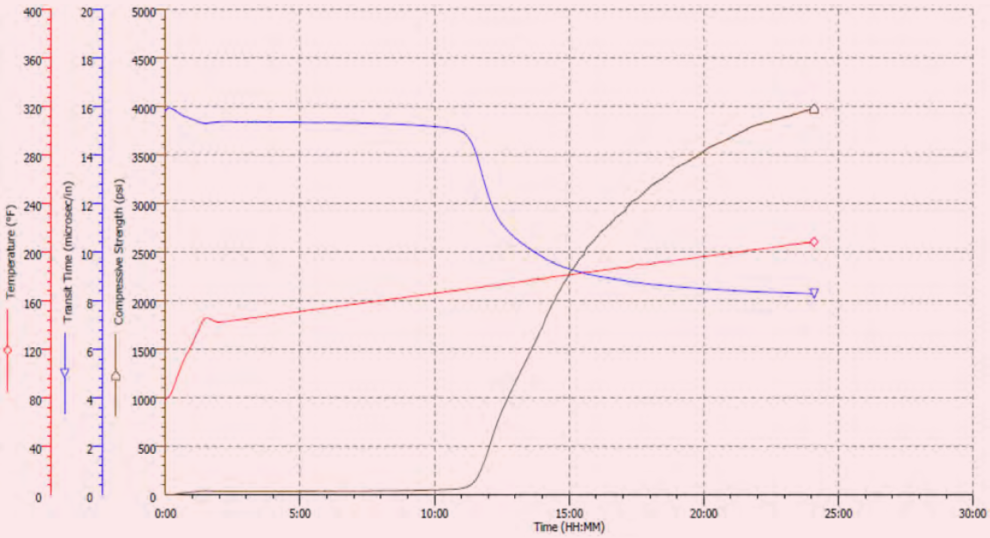


Fig. 3 The compressive strength development for the resin cement system at 135 pcf.



extender. Using resin allowed us to reduce the concentration of the water extender additives, which result in higher compressive strength, Tables 9 and 10.

For the 75 pcf, both formulations were designed in a way to result in high compressive strength. Water extenders were not used as a way to reduce the density at 75 pcf. Instead, high-pressure rating hollow glass spheres were used, which reduce the amount of water required to reduce the density and formulate higher compressive strength than conventional cements at 85 pcf, Fig. 7.

The main advantage of using the resin is to enhance the bonding between the casing and the cement. The test results showed that a higher force was required to remove the pipe in the resin cement system (1,614 lbf) in comparison to conventional cement (945 lbf). For the shear bond for conventional cement at 85 pcf, there was no shear bond observed, Fig. 8. The use of an expansion additive did not show any shear bond at 85 pcf. Subsequently, when we use resin as an additive, the shear bond was measured at 524 Ibf pcf at 85 pcf density. Both were cured at 224 °F and 3,000 psi for 7 days. For the resin cement system at 75 pcf, the same observation occurred. There was no shear bond detected for the conventional hollow glass sphere cement at 75 pcf.

Both the conventional cements, at 85 pcf and 75 pcf, were easily de-bonded from the shear bond testing mold, Fig. 9. It was supported by the shear bond testing done for the resin-based cement at different densities, Fig. 10, that we can definitely enhance bonding between the casing and the cement, and between

Table 3 *The formulation of the resin cement system at 125 pcf. *BWOC is by weight of cement.*

Component	Concentration
Cement	Base
Water	4.01 gal/sack
Antifoam	0.05 gal/sack
Stability enhancer	0.30% BWOC*
Fluid loss	0.15% BWOC
Dispersant	0.80% BWOC
Retarder	1.5% BWOC
Epoxy resin	8.97% BWOC
Curing agent	0.38% BWOC

Table 4 *The properties of the resin cement system at 125 pcf.*

Property	Value
Density	125 pcf
Slurry yield	1.38 ft³/sack
Water requirement	4.01 gal/sack
Total mix fluid	5.209 gal/sack
Thickening time	5.0 hours
300 rpm	242
200 rpm	176
100 rpm	95
60 rpm	67
30 rpm	37
6 rpm	15
3 rpm	11
Free fluid	0%
Fluid loss	90 ml/30 minutes

Fig. 4 *The thickening time test for the resin cement system at 125 pcf.*

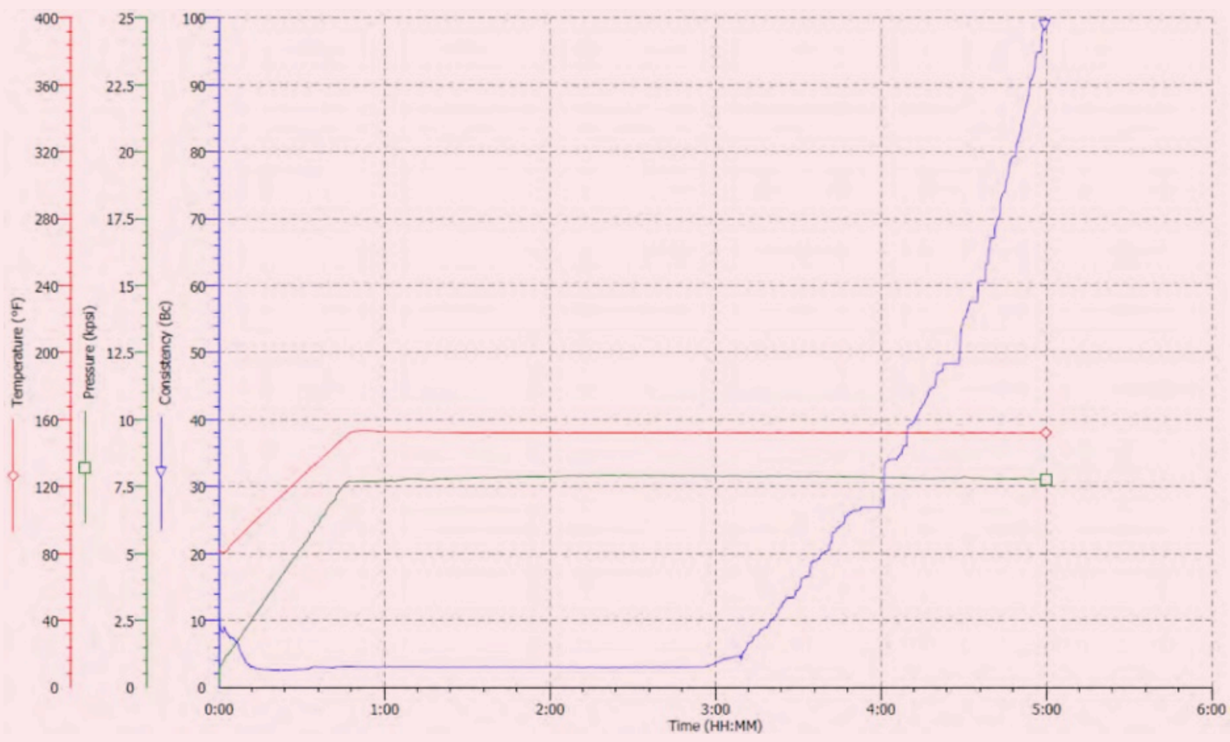


Fig. 5 The compressive strength development for the resin cement system at 125 pcf.

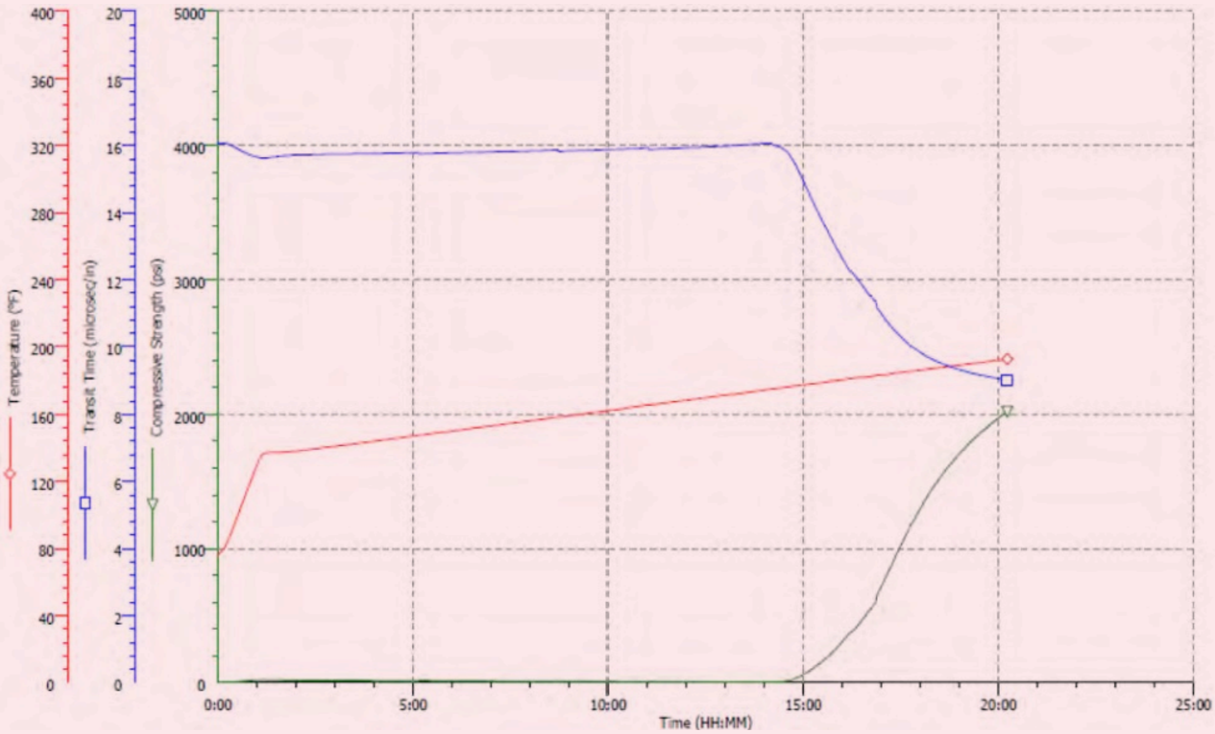


Table 5 The formulation of a conventional cement system at 85 pcf. *BWOC is by weight of cement.

Component	Concentration
Cement	Base
Silica flour	35% BWOC*
Expansion additive	1% BWOC
Water	23.5 gal/sack
Antifoam	0.005 gal/sack
Extender	1.3 gal/sack
Retarder	0.2% BWOC

Table 6 The properties of a conventional cement system at 85 pcf.

Property	Value
Density	85 pcf
Slurry yield	3.99 ft^3/sack
Water requirement	23.5 gal/sack
Total mix fluid	24.8 gal/sack
Thickening time	5.0 hours
300 rpm	18
200 rpm	15
100 rpm	13
60 rpm	12
30 rpm	11
6 rpm	10
3 rpm	9
Free fluid	0%

Table 7 The properties of the resin cement system at 85 pcf.

Property	Value
Density	85 pcf
Thickening time	5.0 hours
300 rpm	97
200 rpm	73
100 rpm	52
60 rpm	41
30 rpm	30
6 rpm	18
3 rpm	15
Free fluid	0%

Table 8 The properties of the resin cement system at 85 pcf.

Property	Value
Density	75 pcf
Thickening time	5 hours
300 rpm	155
200 rpm	119
100 rpm	75
60 rpm	60
30 rpm	41
6 rpm	26
3 rpm	24
Free fluid	0%
Compressive strength	500 psi at 8 hours

the cement and the formation. This enhancement will allow us to improve the wellbore integrity and mitigate any potential issues such as casing-casing annulus (CCA) leaks or failures at the TOLs.

Case History

Typically, two batch mixers were utilized for the resin cement systems application. The slurry is prepared first and then the resin with a curing additive is prepared and added to the conventional cement slurry until the targeted density is achieved. Several jobs were successfully conducted as liners, tie backs, and casings for oil and gas wells.

The cemented sections were pressure tested negative and thereby testing positive, and were exposed to pressure cycling successfully. Further planning and discussions are in progress to deploy formulated epoxy resins for downhole CCA repair, i.e., by milling the casing and accessing the CCA, where feasible.

Conclusions

1. In this study, resin-based cement systems were developed and tested at different densities of 135 pcf, 85 pcf, and 75 pcf.
2. Enhanced bonding was observed for the resin-based cement system compared to the conventional systems.
3. No bonding was observed for the conventional cement systems at low densities of 85 pcf and 75 pcf.
4. A higher compressive strength was observed for the resin cement system at a density of 85 pcf compared to the conventional water extended cement slurries.
5. A high compressive strength was observed for the 75 pcf cement systems (conventional and resin cement) with the use of low SG additives instead of water.
6. A lower Young's modulus value was observed for the 135 pcf resin cement system compared to the conventional system.
7. Reducing the density from 135 pcf to 85 pcf resulted in a reduction of Young's modulus values in the cement systems — resin cement and conventional cement.

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Fig. 6 The static Young's modulus of the cement samples at different densities.

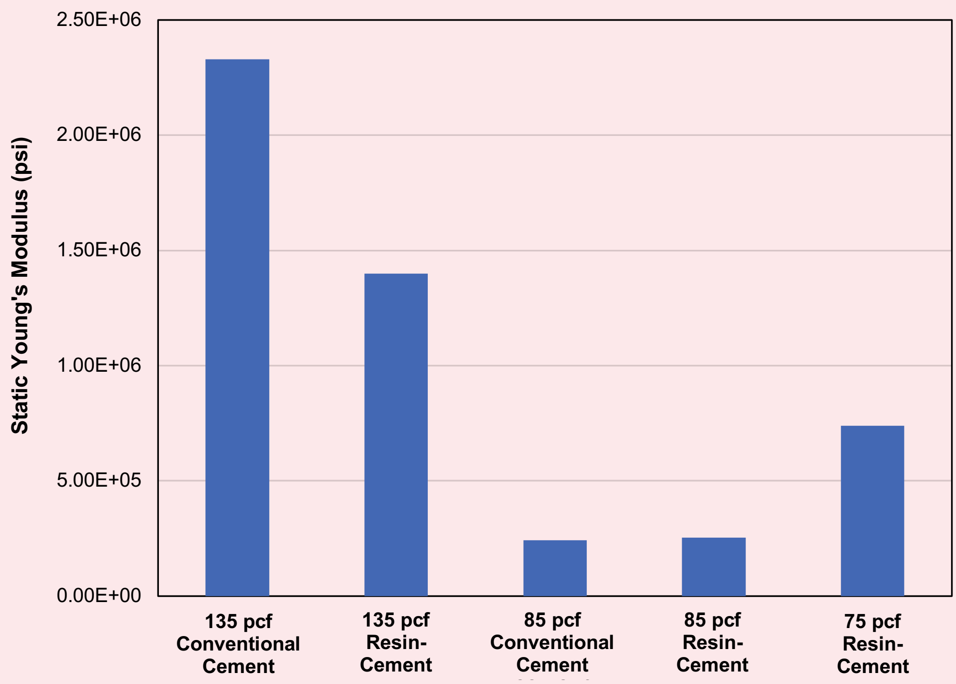

Table 9 The mechanical properties of the conventional cement at 85 pcf.

Young Modulus Static (psi)	Peak Stress (psi)	Yield Stress (psi)	UCS (psi)
2.25E+05	754	644	
2.36E+05	864	754	
2.66E+05	924	813	675

Table 10 The mechanical properties of the conventional cement at 85 pcf.

Young Modulus Static (psi)	Peak Stress (psi)	Yield Stress (psi)	UCS (psi)
2.07E+05	1,274	1,066	
2.64E+05	1,482	1,274	1,065
2.88E+05	1,574	1,366	

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Fig. 7 *The compressive strength of the cement samples at different densities.*

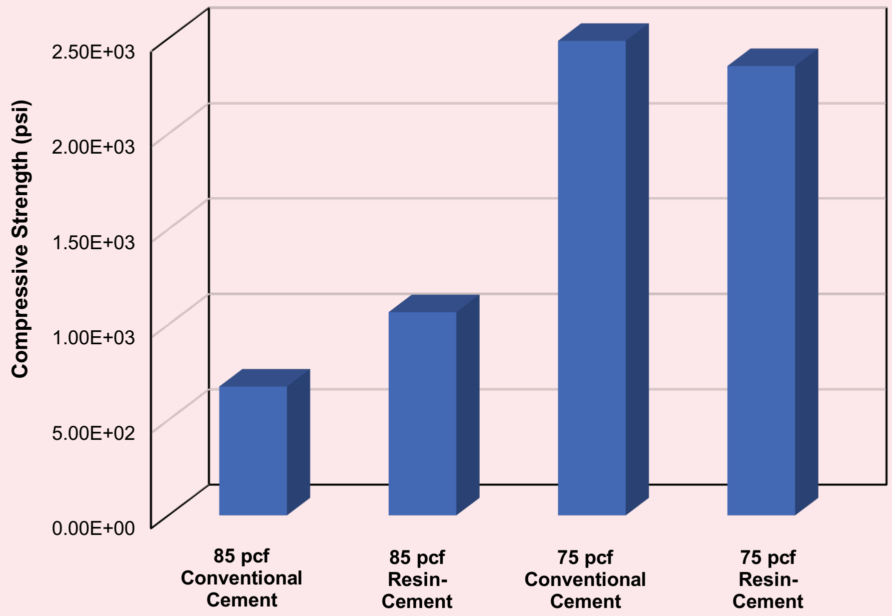


Fig. 8 *The shear bond force for conventional cement vs. resin cement at low densities.*

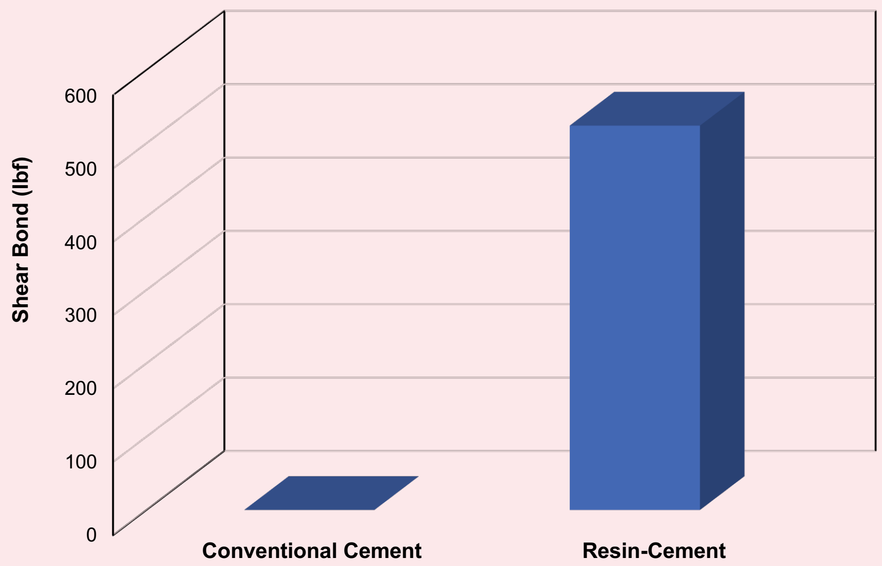


Fig. 9 Both conventional cement systems at 85 pcf and 75 pcf were de-bonded easily compared to the resin cement at the same densities.

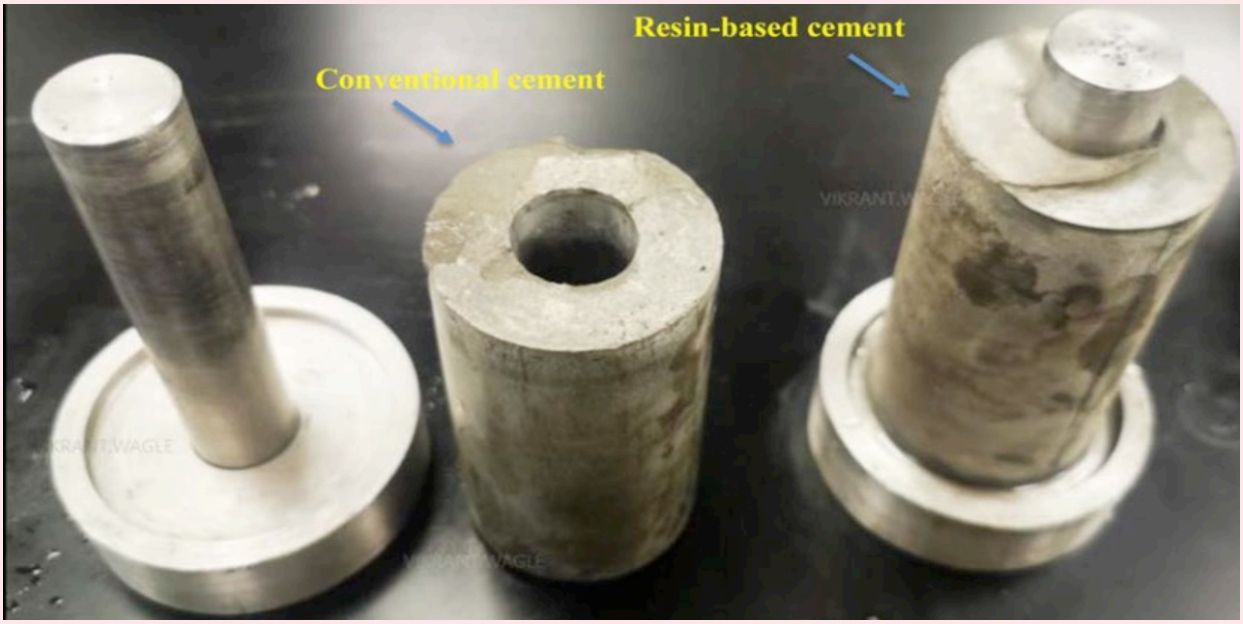
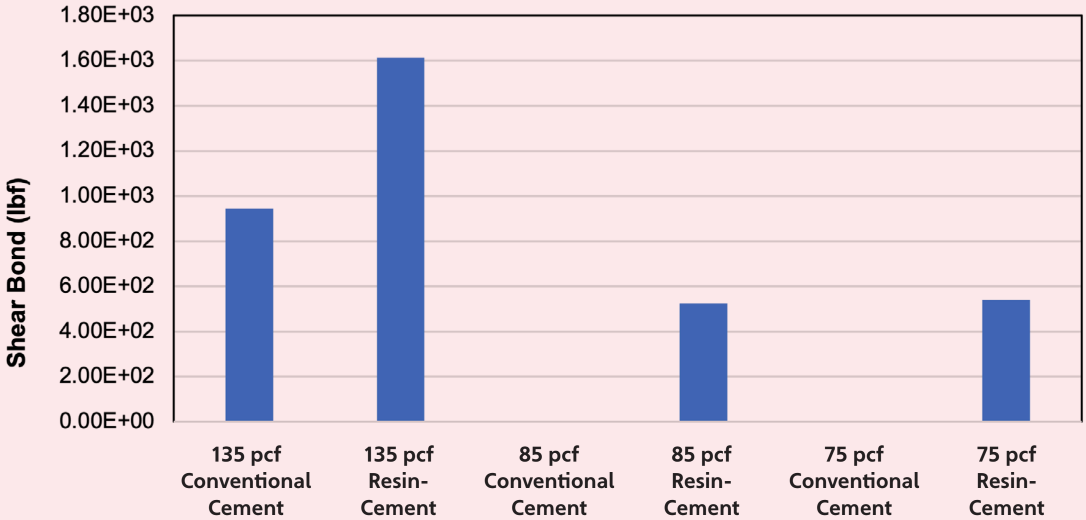


Fig. 10 The shear bond forces for different types of cement at different densities.



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Analysis of Key Sweet Spot Identification Methods and their Significance on Hydrocarbon Well Placement

Menhal A. Al-Ismael and Dr. Abdulaziz M. Albaiz

Abstract /

Sweet spot identification methods are of significant value in optimizing well placement in reservoir simulation studies. These methods vary in their approaches due to the wide-ranging reservoir characteristics and different study objectives. This work analyzes a number of sweet spot identification methods and discusses their advantages and limitations. In addition, we establish a workflow that utilizes a combination of a number of reliable methods.

A simulation model of a synthetic heterogeneous reservoir with 6 million grid cells is used in this work to evaluate six sweet spot identification methods for the purpose of well placement. The evaluated methods use grid cell productivity, fluxes, and sweep ratio, as well as a combination of a number of rock and fluid properties to generate sweet spot 3D maps. Using sweet spot maps from the analyzed methods and the proposed workflow, different well placement scenarios are developed and compared. The results are compared using the total hydrocarbon production and voidage replacement ratio (VRR).

We observe that wells placed using grid cell productivity maps achieve significant improvement in the total hydrocarbon production over a period of 10 years when compared to the other analyzed methods. This method identifies the high productive grid cells, which results in the best performance of wells among the analyzed methods. Although, this method provided less emphasis on the grid cell's proximity and connectivity in the sweet spot map. In heterogeneous reservoirs, this can result in tortuous trajectory paths, which are impractical to drill.

The flux-based method yielded less hydrocarbon production, but a higher VRR. The proposed workflow demonstrated considerable improvements in the total oil production and a balance in the VRR. The new workflow retained the advantages of different methods maintaining a balance between their strengths and marking distinct methodology that can be used for well placement optimization.

This work highlights potential opportunities to improve the sweep efficiency in heterogeneous reservoirs by developing a hybrid workflow that integrates existing tools and methodologies.

Introduction

In the oil and gas industry, field development planning is a critical process that has direct impact on the overall business performance and productivity. Field development planning involves a number of activities such as geology, geophysics, reservoir and production engineering, surface facilities, uncertainty management, economics, and risk assessment. The integration between these activities creates a comprehensive plan that serves as a basis to make economic decisions. One of the primary tools in this process is reservoir simulation, which helps to model the fluid flow behavior in the reservoir and forecast future performance.

Simulation models are of a great importance that are used to guide field development planning subsurface activities. One of those activities is the design and placement of new wells, which has a significant influence on reservoir performance. For that reason, many researchers introduced different methods for well placement optimization using various algorithms and objective functions.

Stochastic optimization is one of the most used approaches in well placement optimization. The particle swarm optimization (PSO) algorithm is one example of such algorithms and was used by Roussennac et al. (2021)[1] to optimize infill well placement, Panahli (2017)[2] to optimize well location, and Jesmani et al. (2016)[3] to optimize well locations with constraints.

Differential evolution (DE) is another popular algorithm in well placement optimization and was used by Al-Ismael et al. (2018)[4] to optimize well placement while maintaining pressure distribution and Awotunde (2016)[5] to optimize well locations, well rates, well type, and well numbers. Also, DE was used by Cihan et al. (2015)[6] to optimize well placement and pressure management of geologic CO_2 sequestration.

Some researchers used hybridization of more than one optimization algorithm to handle the well placement optimization. Kumar (2021)[7] used both PSO and the Covariance matrix adaptation — evolution strategy to improve well placement optimization that was done using PSO only. Nasir et al. (2020)[8] used a hybrid of both PSO and mesh adaptive direct search (MADS) to optimize well spacing, orientation, well location, type, drill/do not drill decision, completion interval, and drilling time variables.

Yazdanpanah et al. (2019)[9] used a combination of the genetic algorithm and PSO into one hybrid algorithm to improve optimization performance. Chen et al. (2018)[10] used a hybrid of the cat swarm optimization algorithm for global search space and the MADS algorithm for local exploration. Yang et al. (2017)[11] hybridized DE and MADS to optimize well type conversion schedules, number of infill wells, locations, and operation schedules. Shirangi and Durlofsky (2015)[12] used a hybrid of the PSO and MADS algorithms for a closed loop optimization of field development plan based on the geological knowledge, drilling new wells, and collecting hard data and production data, and updating multiple geological models based on all of the available data.

Most of these approaches use the optimization algorithm to place wells by maximizing the net present value as the objective function and honoring a number of constraints. The search space is usually the entire 3D grid of the simulation model. The algorithm evaluates a very large number of well placement scenarios by running numerical simulation and computing the objective function. The optimization algorithm searches for the well placement scenario that gives the maximum value of the net present value.

Such an approach might lead to excessive use of high performance computing hardware resources as well as a long turnaround time of the overall well placement optimization. For that reason, some researchers reduced the search space by using sweet spot maps. Al-Ismael et al. (2022a)[13] used the reservoir opportunity index (ROI) to filter the 3D search space and then place the wells using mixed integer programming.

The concept of ROI was originally proposed by a number of researchers by combining a number of reservoir variables to estimate the reservoir quality to help in placing new wells. Molina and Rincon (2009)[14] proposed one of the ROI formulas to identify zones with a high potential of production, and Varela-Pineda et al. (2014)[15] proposed another modification. Abd-Karim and Abd-Raub (2011)[16] proposed another opportunity index, called the simulation opportunity index (SOI). Mustapha and Dias (2018)[17] proposed an index by simply multiplying ROI and SOI, which was also used by other researchers[18]. Zhou et al. (2013)[19] proposed a recovery potential as a combination of some static properties and dynamic properties. The formulas of these sweet spot identification methods are presented in Table 1 in Appendix A.

In addition, some researchers introduced workflow-based sweet spot identification methods. Faqehy et al. (2017)[20] proposed a workflow that extracts static and dynamic information from reservoir simulation results and performs grid cell classification based on sweep efficiency. Al-Qahtani et al. (2020)[21] proposed a workflow based on the productivity index at each grid cell. The workflow assesses the change in the productivity index with time from simulation and calculates an index called the total dynamic productivity index (TDPI). This index is then normalized and used for well placement optimization.

Many researchers rely on these sweet spot identification methods to optimize the placement of new wells. Choosing between the different methods is not a simple task as it depends on many factors. Therefore, the objective of this work is to evaluate a number of published sweet spot identification methods and compare them in the application of well placement optimization. In addition, we propose a new workflow that utilizes a combination of a number of reliable methods.

Methodologies

This study uses a number of popular sweet spot identification methods for the purpose of well placement optimization. Six methods from literature are used to calculate sweet spot maps. These methods have different formulations and approaches. Next, we review the different methods as well as provide a brief explanation on the well design and placement optimization approach.

Sweet Spot Identification Methods

The sweet spot identification methods help to pinpoint the high potential locations within the reservoir. The methods differ in the information they use. Some of the methods use static reservoir information only while others combine both static and dynamic information from the numerical simulation. They combine different parameters using different formulations.

Some other methods use complex workflows that involve running more simulation jobs, which can lead to a more accurate estimation of the sweet spot maps. The final product from these methods is a 3D property, which is normalized between 0 and 1. Following is the description of the methods used in this work.

Opportunity Index (I_{oppor}): One of the popular opportunity indices to identify zones with a high potential of production is the one proposed by Molina and Rincon (2009)[14]. The formula of this index combines three compound variables.

The first variable is the capacity of flow, which is a combination of the horizontal permeability, oil relative permeability, net to gross, and grid cell thickness. The second variable is the porous volume saturated of mobile oil, which combines oil saturation, residual oil saturation, porosity net to gross, and the grid cell thickness. The third variable is the remaining pressure in the reservoir.

The combination of these three variables gives the I_{oppor}. The formula used in this method is presented in Table 1 in Appendix A.

SOI: This is another popular index, proposed by Abd-Karim and Abd-Raub (2011)[16]. This index is a modification of the previously proposed index[14].

Similar to I_{oppor}, the SOI combines three main variables. The first variable is the capacity flow index, which combines the absolute permeability, gross reservoir thickness, and the net to gross ratio. This variable is similar to the capacity of flow used[14], but it doesn't involve the relative permeability. The second variable is the movable oil index, which basically subtracts the residual oil saturation from the oil saturation. The third index is the oil volume index. The combination of these three variables gives the SOI.

The formula used in this method is presented in Table 1 in Appendix A. Note that the major difference in this index compared to the one proposed[14] is that it doesn't involve both pressure and the relative permeability in the formulation.

ROI: The ROI, proposed by Varela-Pineda et al. (2014)[15], was another improvement to the previous developed indices. It incorporates reservoir quality index, mobile oil saturation, and reservoir pressure. The formula used in this method is presented in Table 1 in Appendix A.

The formulation of this index is very close to the ones proposed by Molina and Rincon (2009)[14] and Abd-Karim and Abd-Raub (2011)[16]. Consequently, instead of using the flow capacity, it uses the reservoir quality index, which brings porosity into the formulation.

Opportunity Index (OI): This index was proposed by Mustapha and Dias (2018)[17] by simply multiplying the ROI and SOI indices. The formula used in this method is presented in Table 1 in Appendix A.

Reservoir Sweet Spot Identification (RSSI): Faqehy et al. (2017)[20] proposed a workflow-based method to identify the sweet spot maps. The workflow identifies the unswept connected recoverable oil for field development purposes and it improves reservoir sweep efficiency.

The workflow capitalizes on fluid fluxes to classify the grid cells based on their sweep ratio. It also uses ROI and SOI as quality indicators to identify high production potential regions. The RSSI uses both the sweep ratio (low and moderate values) and the quality indicators (high values) of the grid cells to generate connected volumes, which are ranked based on their size.

TDPI: This method was proposed by Al-Qahtani et al. (2020)[21] to identify the sweet spot maps based on the productivity index at each grid cell. The method produces a 3D property.

TDPI is an integrated simulation-based index that is created through a parallel algorithm that has been devised to calculate reservoir dynamic productivity with efficient utilization of high performance computing resources.

New Proposed Method: The new method proposed in this work capitalizes on the advantages of multiple methods. It is basically a union of both the RSSI and TDPI indices. The 3D index map generated using this method highlights a region as a potential region if both the RSSI and TDPI indices at that region are high.

The new method takes advantage of the RSSI to improve the sweep efficiency by targeting the unswept regions based on fluid fluxes. It also takes advantage of the ROI to target regions with good quality based on static and dynamic properties, as well as from the TDPI to target highly productive regions.

Therefore, the RSSI and TDPI maps are first generated. Then, using predefined cutoff values, we filter out the grid cells that have RSSI and TDPI values less than the cutoff values.

Well Placement

After preparing the sweet spot maps using the different methods, wells are placed to maximize the contact with the sweet spots. In this work, statistical analysis methods are used to perform well placement[22]. The well placement is done using regression after clustering the sweet spot map.

The main advantage of this method is the short turnaround time and the independency on solvers or objection functions that involve running many numerical simulation jobs.

Application Example and Analysis

A simulation model of a synthetic heterogeneous reservoir with 6 million grid cells is used in this work to evaluate a number of sweet spot identification methods. The simulation model consists of one existing oil producer and one water injector. The application example involves creating different horizontal well design and placement optimization scenarios using different sweet spot maps, and then assess their performance using numerical simulation. The simulation cases of all the scenarios have a prediction period of 10 years. The numerical simulation is performed using the in-house state-of-the-art GigaPOWERS reservoir simulator[23].

Six sweet spot maps are prepared using different methods. The methods considered in this work are TDPI[21], ROI[15], SOI[16], RSSI[20], I_{oppor}[14], and OI[17]. The sweet spot maps are calculated using the simulation results of the base case at the start of the prediction period. The six sweet spot maps are normalized between 0 and 1. Grid cells with a value of 0 indicate low quality, while grid cells with a value approaching 1 indicate the best quality, and therefore needs to be targeted during well design and placement optimization. The sweet spot maps are filtered to show only the high potential grid cells. The filtering was done using the 99th percentile, which produced 60,000 grid cells. This represents the top 1% from all the grid cells. The filtered sweet spot maps generated in this work are presented in Fig. 1. Each image presents the top view of a 3D filtered sweet spot property to highlight the high potential regions that will be targeted during well placement.

As can be observed in Fig. 1, all the maps show the same trend of distribution, but they are all different from each other. The visualization of the maps might show that the difference is insignificant; however, this level of difference has a great impact on the well placement results.

Ten oil producers are designed and placed optimally on each sweet spot map. This creates six optimization scenarios. The well design and placement optimization is done using statistical data analysis. The objective function of the optimization is maximization of the proximity between the newly created wells and the sweet spot map. Figure 2 shows the new horizontal wells designed and placed on the different sweet spot maps using the statistical analysis methods. The coloring of the sweet spot 3D map is made transparent to allow visualizing wells placed in different layers.

As can be observed in Fig. 2, each sweet spot map resulted in different distribution of the wells. The locations, directions and depths are different in each sweet spot map. The images shows the top view of the 3D model. Therefore, wells that appear crossing each other are actually placed in different layers.

The proposed sweet spot map is also generated on the same simulation case. The cutoff values used are 0.5 for RSSI and 0.3 for TDPI. These cutoff values are carefully selected to ensure having almost the same number of grid cells as the other six sweet spot maps, which is around 60,000 grid cells. The new generated sweet spot map is re-normalized between 0 and 1. Wells are also placed on this map using the statistical analysis methods to minimize the proximity between the new wells and the sweet spot map grid cells. The new generated oil production wells using the new proposed sweet spot map (combined) is presented in Fig. 3.

As can be observed in Fig. 3, the generated wells are different

Fig. 1 The filtered sweet spot maps generated using different methods.

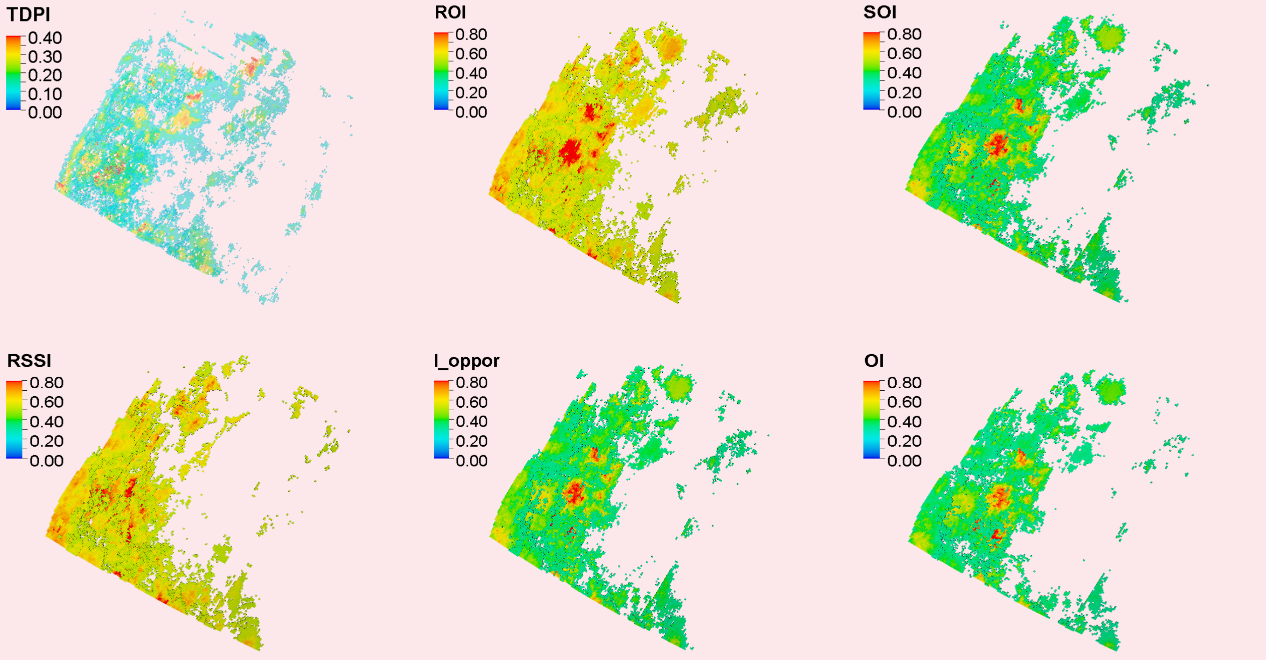


Fig. 2 The new wells designed and placed on different sweet spot maps.

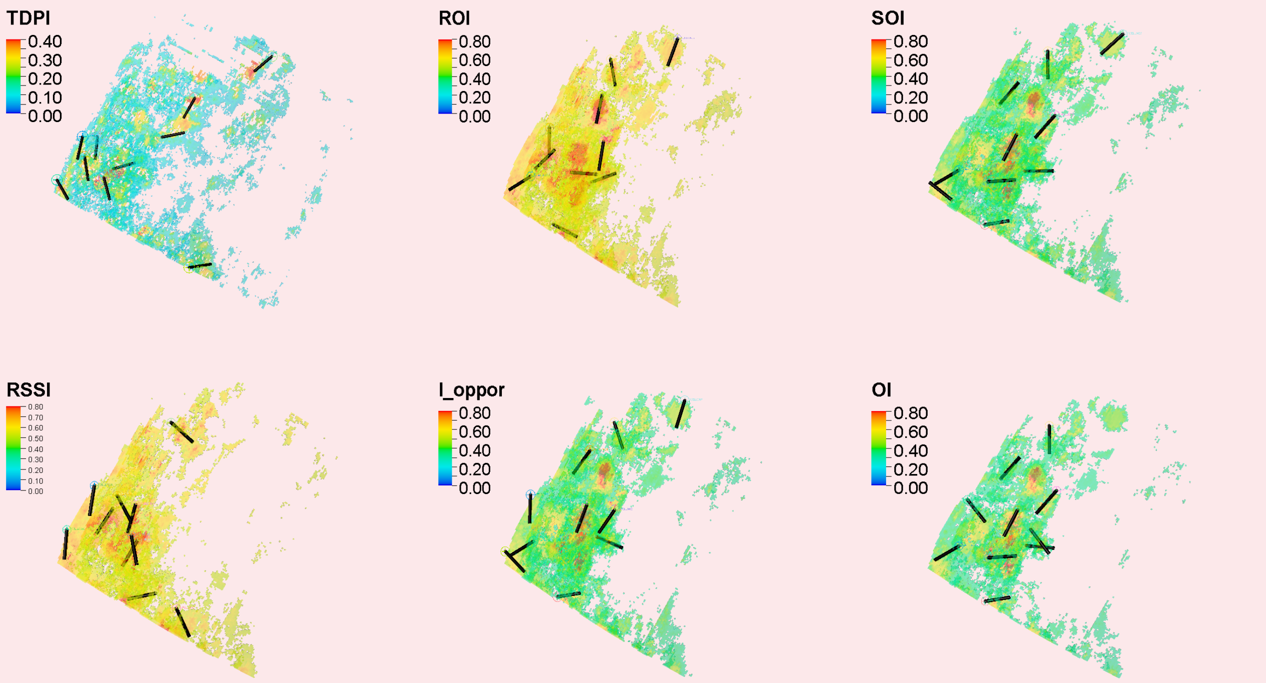
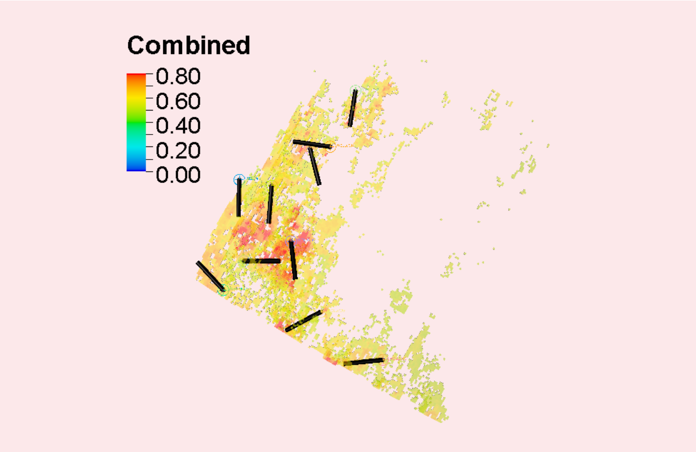


Fig. 3 *The new wells designed and placed on the new proposed sweet spot map.*



than all the wells in the other six scenarios. The difference in well locations and design between all the scenarios shows the significance of the method used in identifying the sweet spot map.

Numerical simulation is performed on all the scenarios to forecast the performance of the wells. Figure 4 shows the total oil production from all of the scenarios. We observe that the proposed method outperforms all the other methods. It resulted in 3% more oil production than the TDPI, and 3.4% more oil production than the RSSI. In addition, the voidage replacement ratio (VRR) can provide some indication on the performance between these cases. Although there is only one existing water injector, the VRR profile is different between the tested scenarios, Fig. 5. The new proposed method shows a higher VRR than the RSSI until 2026, but later RSSI results in a higher VRR.

The application example and analysis in this work show that workflow-based sweet spot identification methods — the RSSI and the TDPI — can outperform the classical methods that are based on formulas like the ROI and the SOI. This is because these workflow-based methods rely on a wider scope of features and characteristics.

For example, the RSSI makes use of fluid fluxes to assess the level of reservoir sweep in addition to using quality indicators like the ROI and the RSSI. This is the reason that the RSSI shows better performance compared to other methods, especially in VRR. Also, the TDPI relies on the productivity of the grid cells rather than just looking at the dynamic and static properties. The productivity of the grid cells from numerical simulation is a direct measure of the quality and can be more reliable in the placement of the new wells.

For this reason, the TDPI resulted in more total oil production than the formula-based methods (6.5% higher) and the RSSI (0.4% higher). Combining the features from both workflows, the proposed method managed to improve the total oil production as well as a relatively good VRR that balances between the RSSI and the TDPI.

Conclusions

This work analyzed a number of sweet spot identification methods for the purpose of optimizing well placement. Well placement is achieved by using statistical analysis methods over the 3D

Fig. 4 *The total oil production from all of the scenarios.*

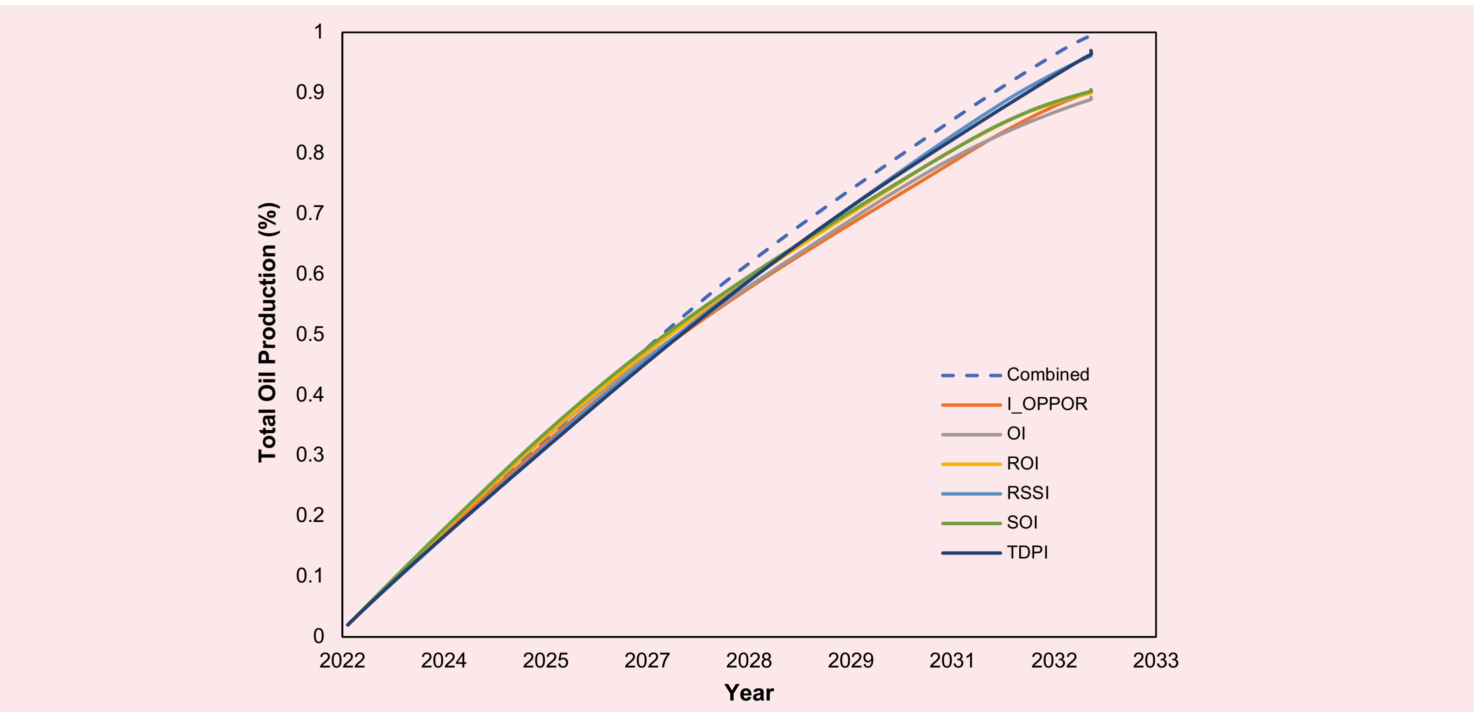
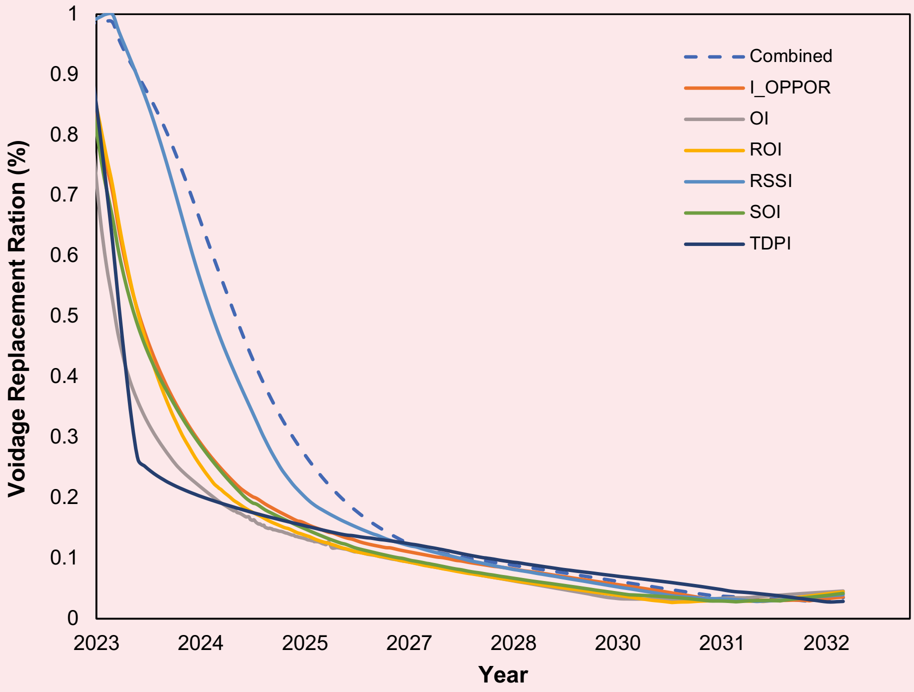


Fig. 5 The VRR profile of all the scenarios.



sweet spot maps. Results are compared using total hydrocarbon production and the VRR. Also, a combination of more than one method was proposed to create a new sweet spot map.

The application example presented in this work showed the variation of the performance using the different maps and the superiority of the new proposed method. The new proposed method retained the advantages of different methods maintaining a balance between their strengths and marking distinct methodology that can be used for well placement optimization.

This work highlights potential opportunities to improve the sweep efficiency in heterogeneous reservoirs by developing a hybrid workflow that integrates existing tools and methodologies.

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Appendix A — Formulas of Sweet Spot Identification Methods

Table 1 presents some of the published sweet spot identification methods.

Table 1 *The sweet spot map formulas.*

Opportunity Index	Reference
$I_{oppor} = \sqrt[3]{I_{KH} \times I_{HCPV_m} \times I_{P\_oper}}$ $I_{KH} = k \times k_{ro} \times NTG \times D_z$ $I_{HCPV_m} = (S_o - S_{or}) \times \phi \times NTG \times D_z$ $I_{P\_oper} = P - P_a$	Molina and Rincon (2009)[18]
$SOI = \sqrt[3]{MOI \times CFI \times OVI}$ $CFI = k \times D_z \times NTG$ $MOI = S_o - S_{or}$ $OVI = MOI \times \phi \times D_z \times NTG$	Abd-Karim and Abd-Raub (2011)[20]
$RF = kh(P - P_{wf}) \times Dist$	Zhou et al. (2013)[23]
$ROI = \sqrt[3]{RQI \times SOMPV \times P}$ $RQI = 0.0314 \times \sqrt{k/\phi}$ $SOMPV = (S_o - S_{or}) \times \phi \times D_z \times NTG$	Varela-Pineda et al. (2014)[19]
$OI = 0.31548 \times NTG \times D_z \times (S_o - S_{or}) \times \sqrt{k \times \phi} \times \sqrt[3]{P - P_{reference}}$	Mustapha and Dias (2018)[21]

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Mechanical Evaluation and Intervention in Nonmetallic Tubulars Using Current Technologies

Mohamed Larbi Zeghlache, Dr. Khaled Almuhammadi, Pervaiz Iqbal and Sandip Maity

Abstract /

With increasing interest in nonmetallic products for downhole applications, such as fiberglass tubing, it is essential to ensure that the well integrity is similar as the standard carbon steel completions. One important aspect of well integrity is the ability to routinely access the downhole condition of the tubing and perform basic intervention. This article demonstrates the testing and validation of different mechanical evaluations of the integrity of fiberglass tubing using logging and intervention tools.

In this work, two joints of fiberglass were connected together to study the effect of logging and intervention tools on the integrity of these joints from the inner and outer surfaces as well as the structural integrity. For the inner wall evaluation, a multifinger caliper tool was run inside the two joints several times to investigate potential damage caused by the fingers. In addition, a tubing puncher was used to punch a hole and characterize the surface damage and any effects on the structural integrity of the fiberglass. Furthermore, a tubing cut was performed to confirm the performance of the cutting tool in such an environment. All the tests were conducted safely and successfully at the surface using two different sizes of fiberglass tubing.

The tested tubulars were split to further investigate the internal condition. The effect of the applied fingertips on the inner wall surface of the fiberglass from several passes indicated minor scratches that can be further investigated using an accelerated wear test. The integrity of this nonmetallic tubular can be evaluated using standard mechanical tools to identify defects and scale buildup. Other intervention tools such as the mechanical puncher and cutter indicated successful deployment under surface conditions.

An investigation of existing downhole evaluation and intervention technologies can provide an immediate assessment of the benefits and limitations with respect to unconventional completions such as the fiberglass tubing and other nonmetallic pipes. Future research and development programs can rely on such solid basis to tailor advanced solutions for any specific application or products.

Introduction

The use of advanced composite materials has significantly increased recently. They have surpassed metals and alloys as potential candidate materials for structural components. Their strength and lightness have made them particularly attractive for many applications in oil and gas, civil construction, automotive, aerospace, and other fields. Their advantages include better corrosion and fatigue resistance when compared to metals, high stiffness-to-weight ratio, which helps to reduce the weight of the components, design flexibility, lower assembly, and maintenance costs.

The composite materials are increasingly being deployed across all multiple upstream domains and downhole applications. They have a wide spectrum when it comes to upstream applications in drilling, completion, producing, and intervention applications. They include different types of reinforcements within the thermoplastic or thermoset matrix, as well as elastomers.

Out of the advanced composite materials, fiber-reinforced polymer composites have been used efficiently for various structural applications, including primary structures for which safety is a major design requirement. Consequently, fiber-reinforced laminate is very sensitive to the out-of-plane loading, such as impact, since it exhibits relatively low transverse properties[1]. The resulting impact damage in fiber-reinforced polymer composite usually reduces its post-impact mechanical properties (compression after impact strength), and jeopardizes the overall integrity of the structure.

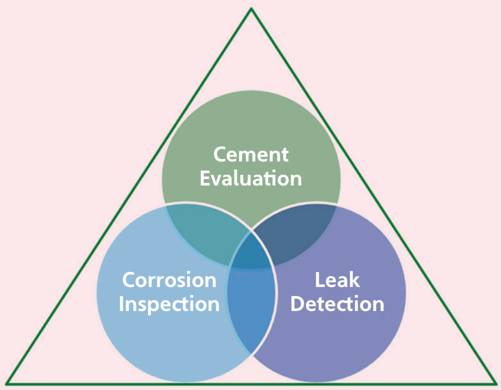
The damage phenomenology in fiber-reinforced polymer composites involves many different mechanisms of degradation[2]. In the case of fiber-reinforced polymer composite under a low-energy impact, a relatively large delamination at ply interfaces (a separation of the layers) inside fiber-reinforced polymer laminate may exist without an observable dent on the skin of the structure[3]. Contrary to metallic materials in which the contribution of plasticity is more dominant than that of damage[4], fiber-reinforced polymer composites can experience damage evolution followed by a catastrophic failure without prior notice.

The inspection, as well as monitoring of such damage during the structure's lifetime prior to failure are very challenging. Moreover, the classical non-destructive testing techniques are difficult for being implemented for real-time structural health monitoring. As a consequence, the advanced composite materials are not being exploited at their full potential for building critical load-bearing structures. It is therefore important to develop a reliable structural health monitoring technique that can both increase safety and reduce operational costs by optimizing inspection and repair.

Logging Technologies for Nonmetallic Tubulars

Since the early exploration and development of oil and gas fields, well integrity became a central part of safety and efficiency. Programs and procedures are put in place to safeguard people, assets, and the environment. Most of these programs are under what is often called a well integrity management system. Downhole evaluation of well integrity is part and parcel of these programs and deals with proactive and routine diagnostics, which is one of the major elements of preventing well integrity failures.

Fig. 1 The well integrity triangle.



Similar to the fire triangle, the well integrity triangle, Fig. 1, is composed of three main pillars, which makes a barrier against any unwanted flow of liquids and gas from downhole to the surface or across formation layers. The three components of well integrity barriers are cement, casing, and flow path. To ensure barrier integrity, both inner barrier, which is casing and outer barrier, which is cement, have to be in good condition and well bonded to prevent any unwanted flow. Considering this configuration, it is important to note that well integrity evaluation has to deal with these three elements to properly diagnosis any potential hazard.

Logging technologies have been developed since the early days and mainly characterized for metallic completions. Figure 2 shows how they are mainly divided into two main categories: barrier inspection for casing corrosion and cement evaluation, in addition to diagnostic services for flow monitoring[5]. For diagnostic services, these technologies might not need any major upgrade or modification to be used in nonmetallic tubulars. Although, barrier inspection technologies would require a major adaptation or even a complete research and development of new solutions.

Well Integrity Evaluation

From the list of barrier inspection technologies, cement evaluation using sonic and ultrasonic measurement will be very challenging across coated or nonmetallic casing. For example, pipes that are coated with a low acoustic impedance ($Z < 15$ MRayls) material, such as fiberglass (ZFG ~ 2.3 MRayls), current physical models and measurement characterization of pulse-echo acoustic impedance tools, do not provide a reliable acoustic impedance calculation due to signal attenuation across the coating material layer. In this case, the acoustic impedance and the thickness of the coating layer must be known.

For the case of nonmetallic pipes, such as fiberglass and composite pipes, this measurement is yet to be investigated for proper transducer design and signal processing. For the magnetic and

Fig. 2 The classification of well integrity evaluation technologies.

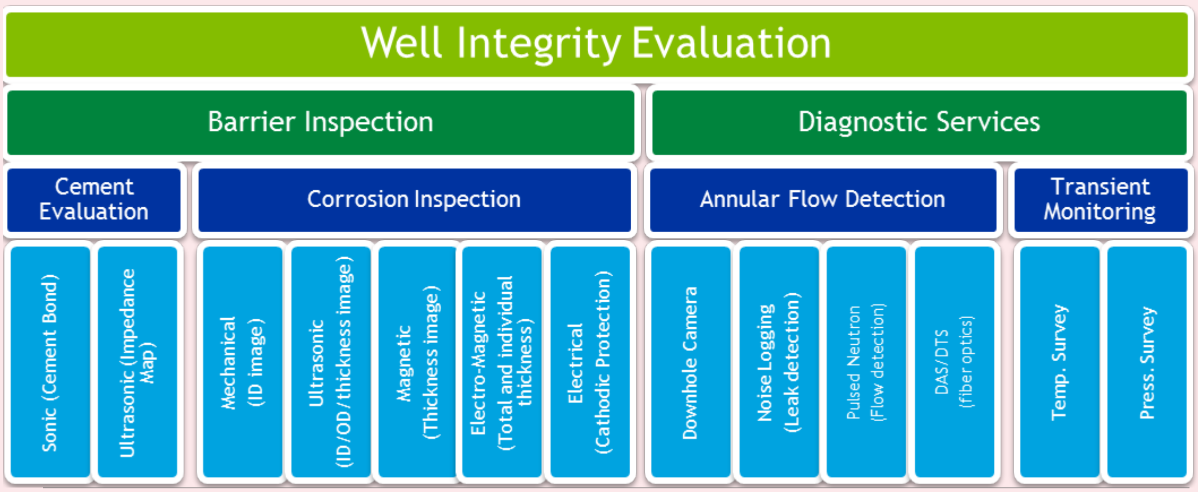


Fig. 3 The accelerated wear testing of caliper fingers.

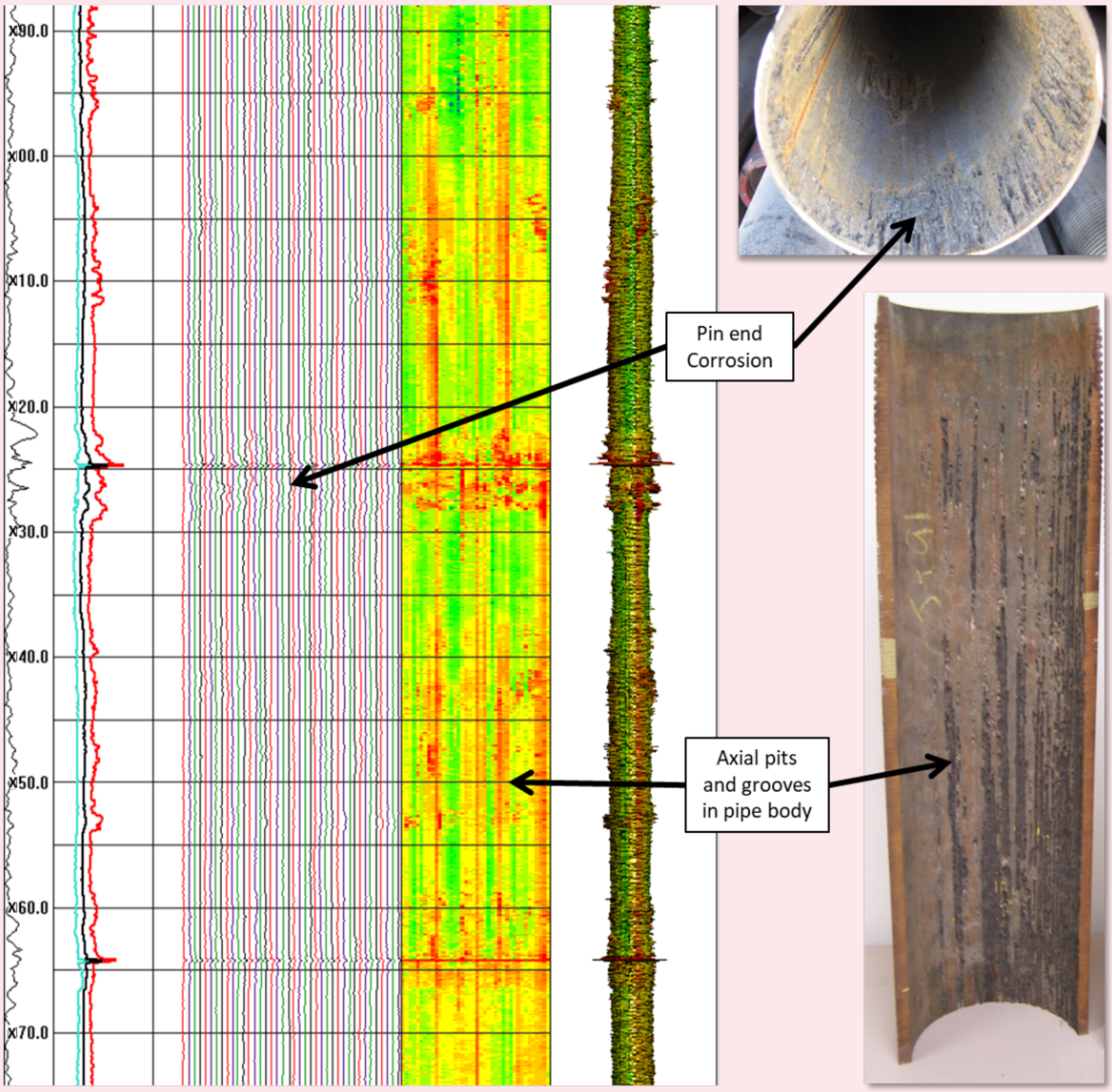
electromagnetic technologies, they cannot be used for casing inspection by design, since the pipe material is an insulator and prevents any current flow.

The simplest and straightforward technology remaining on the list is the mechanical tools for inner wall inspection. For this reason, testing was done to evaluate the effectiveness of multifinger caliper logging in fiberglass casing, in addition to simulating intervention operation through puncher and cutter services.

Multifinger Caliper Log in Steel Casing

The main concern of multifinger caliper tool deployment in a fiberglass casing or composite material is to study the short-term and long-term effects of mechanical contact from the tip of the multifingers on the inner surface of the tubulars. This phenomenon has been reported in the literature where finger-tip material is studied for wear to set a threshold for the tip replacement as well as the potential scratches that may lead to somehow preferred corrosion patterns. The former concern is

Fig. 4 An example of corrosion patterns in carbon steel pipes.



usually addressed using a special device where the tip is mounted on an arm that experiences a known pressure on a specific material disc. The disc is allowed to rotate at an adjustable speed. Figure 3 shows the testing in progress and is referred to as accelerated wear testing.

Figure 4 is an example of the wear on the tubular's inner wall, due to applied pressure by the fingers or other surveillance and intervention technologies. This example of the log data shows traces of fingertip scratches, creating a preferred path for corrosion. Obviously, this case is related to the selection of tubular material and downhole condition for some isolated cases.

Multifinger Caliper Log in Fiberglass

Fiberglass Logging Experiment: Since multifinger caliper

Fig. 5 The fiberglass test setup for multifinger caliper logging passes.

Fig. 6 The multifinger caliper results from pass 1 along with a cross section of the top section.

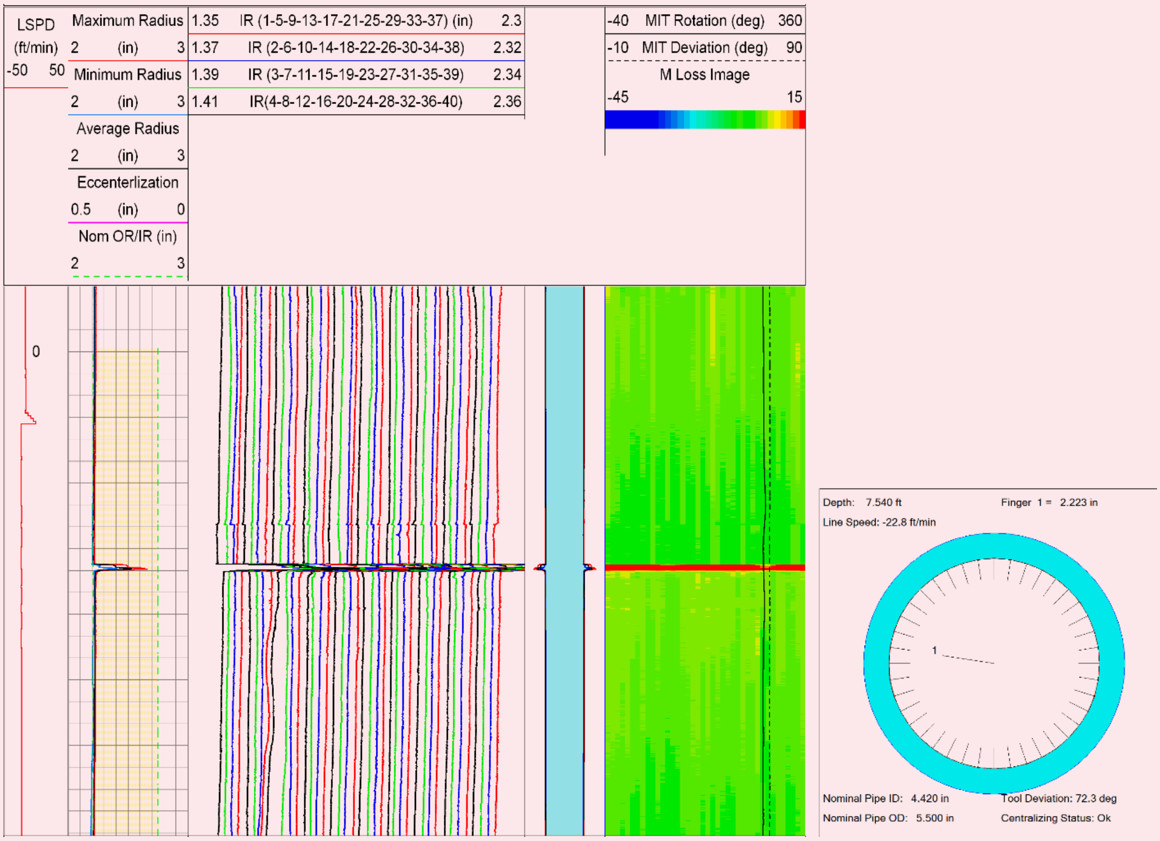
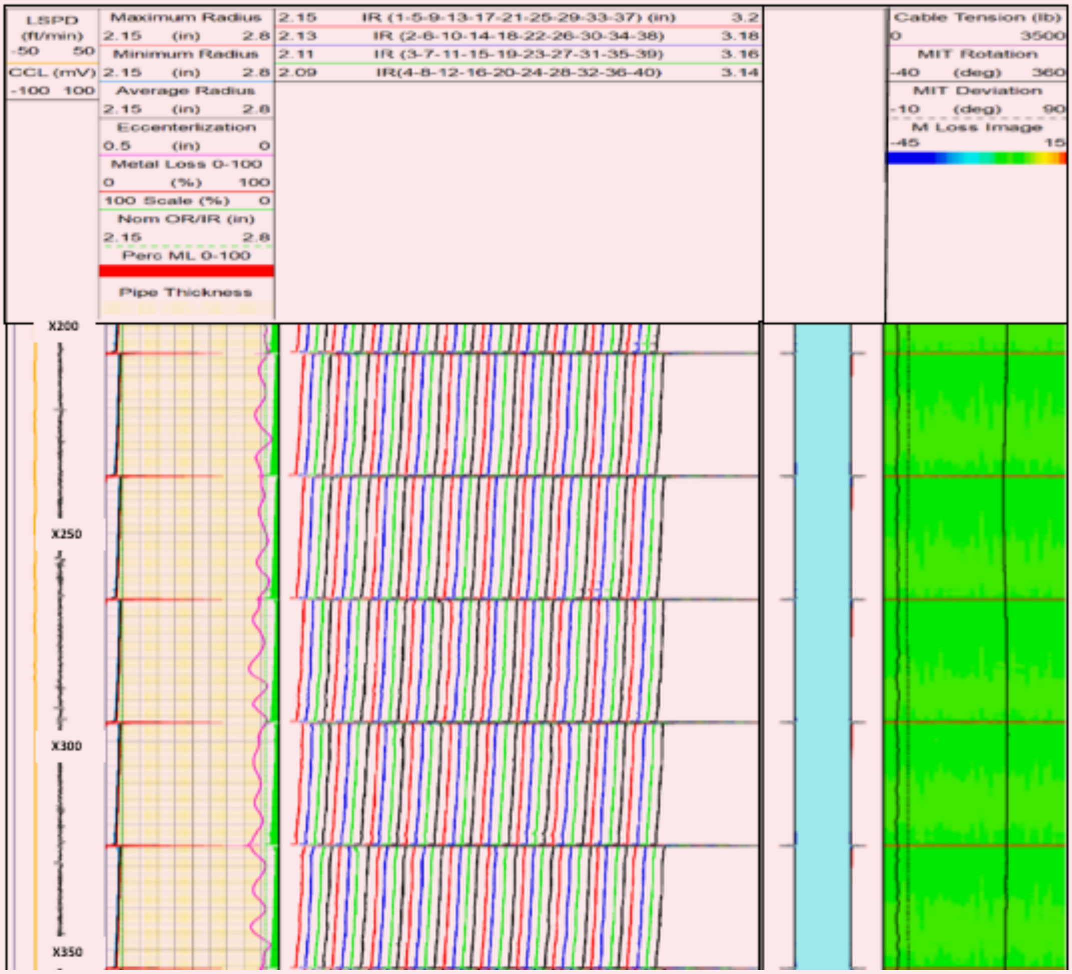


Fig. 7 The low side of the fiberglass pipe after multifinger caliper logging passes.

Fig. 8 The high side of a fiberglass pipe after multifinger caliper logging passes.

Fig. 9 The multifinger caliper results across the logged interval at the shallow section.



fingers have some contact force exerted on the casing/tubing wall, it is safe to use in standard carbon steel pipes[6]. Moreover, it is important to study the condition of a fiberglass surface after multifinger caliper tool logging. Additionally, tubing puncture and tubing cut tests are also conducted for future intervention operations.

For this experiment, two fiberglass joints were used for the study. They were laid down horizontally and three multifinger caliper logging passes were conducted while the tool was pushed in with fingers closed and then pulled out for logging passes at a constant speed. This operation was repeated three times to ensure measurement repeatability and to confirm any pattern, Fig. 5.

Figure 6 presents the results from one of the three multifinger caliper tests across two joints of fiberglass pipes. Track-1 shows the depth and logging speed in ft/min, and Track-2 shows the minimum radius, average radius, and maximum radius along with the nominal radius and outer radius of the casing. Track-3 shows the individual 40 fingers' data of the multifinger caliper tool, and Track-4 shows the inner wall profile from the minimum radius, average radius, and maximum radius. Track-5 shows a 2D image of the multifinger caliper 40 fingers along with multifinger caliper rotation and deviation.

The color pallet used shows the nominal internal diameter (ID) in green, an increase in ID (commonly referred as metal loss for carbon steel pipes) in red, and a decrease in ID, which commonly refers to scale buildup.

All passes showed good data quality and the measured radius closely matches with the nominal radius of the fiberglass pipes. Also, the pin to box connection gap was identified by all fingers and clearly seen on the 2D map as a red horizontal line.

After logging the multifinger caliper passes, a section of one of the joints was cut into two halves to see the internal condition of the low side, Fig. 7, and the high side, Fig. 8, of the pipe after the multifinger caliper tool logging. There were minor scratches as a result of the multifinger caliper fingers as well as downward tool movement. The depth of the scratches will be assessed and correlated to the accelerated wear test results.

Field Test Results: For the first deployment of nonmetallic tubulars in a downhole application, integrity evaluation of these pipes is required after exposure to downhole conditions and multiple trips with different bottom-hole assemblies. The 5½" fiberglass tubing deployed in an injector well was selected as a candidate for a multifinger caliper survey, and to establish a baseline log as well as for future time-lapse surveys.

The well consists of completed standard carbon steel casings ranging from a size of 20" down to 9⅝". The last string is the 5½" size nonmetallic tubing. Figure 9 presents the multifinger caliper results across the logged interval at the shallow section. The log indicated that the tubing was free from any significant defect, confirming the integrity of the inner wall of the nonmetallic tubing at in situ conditions. The maximum radius curve was mostly featureless at the high side, which implied that no defects are observed.

This indicates the successful deployment of this solution to overcome standard carbon steel pitting corrosion due to high speed water flow. Moreover, the average radius measurement was approximating around the nominal pipe radius. This indicates that the 5½" tubing was free from any circumferential wall thinning at any level. The minimum radius was also featureless, indicating no deposits or scale buildup too.

Intervention Technology Test in Fiberglass

The mechanical pipe cutter reduces logistical and environmental constraints, delivering precise downhole pipe cutting without ballistics or hazardous chemicals, thereby reducing nonproductive time, risk, and intervention costs. The tool also delivers precise downhole pipe cutting without damaging external tubulars since the blade extension does not reach the outer pipes. The cutting penetration is continuously measured and controlled, confirming the cut has been made and avoiding damage to external tubulars or control lines.

The mechanical pipe cutter was used to cut the fiberglass tubing section while monitoring the tool performance and internal parameters. The 5½" fiberglass tubing was cut successfully in approximately 7 minutes. Figure 10 shows the small cut piece and the horizontal position of the tool inside the pipe.

Furthermore, the mechanical pipe cutter was also tested for tubing puncture, which was also done successfully in a few minutes, Fig. 11.

Investigation of Future Technologies in Nonmetallic Composites

Previously, we described multifinger technology to characterize the structural change of the fiberglass tubing inner wall. The requirements for the next generation of sensing devices are quite high. Ideally, they should be able to sense different physical parameters, in situ, on a (sub-)micrometer scale and without affecting the mechanical performance of the host component. For this purpose, integrated solutions can be employed for downhole quantitative inspection of nonmetallic tubing such as fiberglass, carbon fiber reinforced polyvinylidene fluoride, or high density polyethylene tubing inspection (3" to 4½" or

Fig. 10 The mechanical pipe cutter test cut results.

Fig. 11 The mechanical pipe cutter tubing puncture test results.

other available size), or flatbed. Also, embedded smart sensors or different non-destructive evaluation techniques can be used for quality control during manufacturing. Although, knowledge of nonmetallic inspection either for downhole logging or during the manufacturing process is limited in the oil and gas industry.

It is eminent from the technology landscape that a few existing inspection technologies are available or reengineered for fit for purpose. There is a technology gap, which is needed to address in a holistic manner toward in situ monitoring to harness the Fourth Revolution Industrial technology, Fig. 12. Another emerging non-destructive evaluation method is tera hertz optical tomography, also popular for composite inspection for advanced defense material. Consequently, these methods are challenging in a downhole environment and can be used only during the manufacturing process for quality control or the precommissioning phase.

Conclusions

Current sustainability efforts around the globe include reducing environmental risks and maintenance cost in oil and gas surface and downhole assets. This is materialized in the substitution of traditional carbon steel components with nonmetallic composite material such as fiberglass tubulars. As many programs involve asset integrity management, downhole evaluation is a pillar of the well integrity management system and it is important to evaluate current technologies for these emerging applications.

The future development of composite materials and other nonmetallic components comes with new challenges that surface and downhole evaluation technologies have to address. The straightforward deployment of mechanical evaluation tools, such as the multifinger calipers, is just a start to develop fit for purpose solutions for different modes of defects and locations within the completion.

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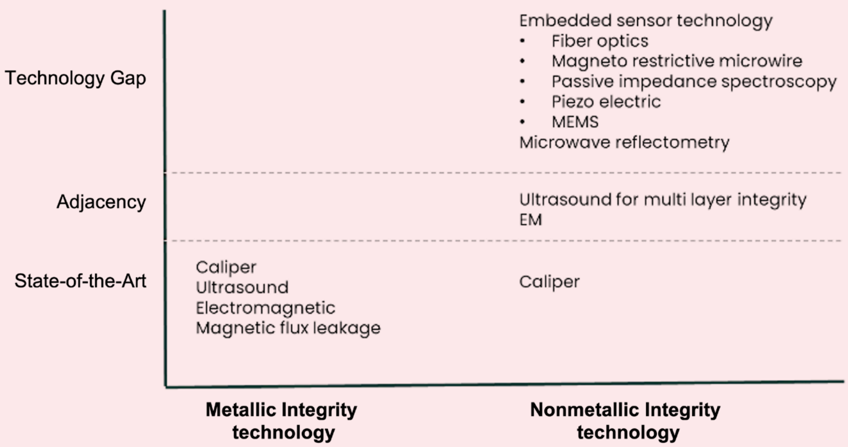
Fig. 12 The nonmetallic casing/tubing integrity technology landscape.



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Successful Development and Deployment of a Novel Inhibited Cement System

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Abstract /

Potassium chloride (KCl) is typically used in the formulation of cement spacers to inhibit the shales from swelling and dispersion. It serves as a shale inhibitor during cementing operations to ensure good wellbore integrity. To obtain optimum inhibition, a high concentration of KCl might be required. A massive amount of KCl will lead to a negative impact on the environment, cement slurry setting time, and wireline logging methods. This work strives to design and synthesize a novel inhibited cement system with an improved shale inhibition performance and wellbore integrity without harming the ecosystem.

A spacer and cement formulation utilizing a novel mixture of different high molecular weight polyamines have been prepared successfully and compared against conventional formulations. Our study includes dispersion testing using representative shale samples and spacer compatibility with water-based drilling fluids and cement. The compatibility investigation included rheology testing, thickening time testing, compressive strength measurements, and free water tests.

The study shows that the KCl concentration should be monitored carefully to avoid cement immature settings. KCl salt also resulted in improper wellbore integrity due to its low performance in shale inhibition compared to amines. Amines did not result in retardation nor acceleration of cement setting. Representative shale dispersion with cement filtrates and spacers show a high dispersion recovery factor of 96.5%, with the novel polyamine additive compared to 82% with KCl.

We illustrate detailed experimental and field applications of a novel mixture of different high molecular weight polyamines. Contrary to conventional KCl, the new formulation resulted in improved shale inhibition and enhanced wellbore integrity. The value of this study was further validated by the successful execution of cementing a casing installed in a water sensitive shale formation.

Introduction

Zonal isolation is one of the fundamental elements in wellbore integrity and drilling phases. Cement is pumped between the casing and the formation to provide a reliable hydraulic seal in the wellbore annulus, enabling selective fluid production from underground formations while preventing leakage into other formations or to the surface[1]. Undesirable water/oil could enter the casing through inadequate or nonexistent cement, and contaminate the freshwater-bearing formations, Fig. 1.

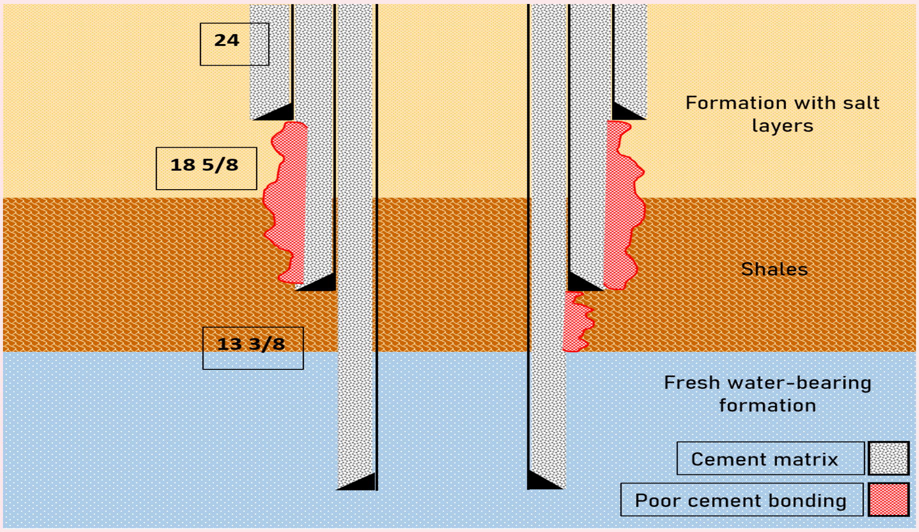
A successful cementing operation comprises many factors, such as casing centralization, wellbore fluid design, efficient mud displacement, cement formation bonding, and spacer formulation design. Spacer fluids are often circulated before cement displacement to prevent the drilling mud from coming into contact with the cement slurry, thereby improving the cement formation bonding by removing an oil film from the surface of the casing and formation, and coating the shales to prevent swelling or cracking.

Potassium chloride (KCl) is used as a shale inhibitor in the design of cement spacer formulations at the moment. To obtain adequate inhibition efficiency, KCl must be added to the spacer at a high concentration; however, this has a detrimental effect on the environment, and wireline logging tools. The extended time it takes for the cement slurry to set is because the interaction of KCl with the clays left a significant amount of chloride ions in the mud solution[2]. In this study, we design and synthesize a novel inhibited cement system with an improved shale inhibition performance and wellbore integrity, by utilizing a unique mixture of different high molecular weight polyamines to give the desired properties without having any detrimental effects on the environment or cement slurry.

Shale Inhibitors

Shale inhibitors are chemicals that restrict how much water can interact with clay particles, consequently preventing or minimizing shale swelling or dispersion, over two different mechanisms, which are cation exchange and encapsulation. Many studies have been conducted over a long period of time to assess the effects of drilling fluids on clay-rich formations and to identify ways to reduce and manage those effects. Excellent

Fig. 1 *An example of bad cement formation bonding.*



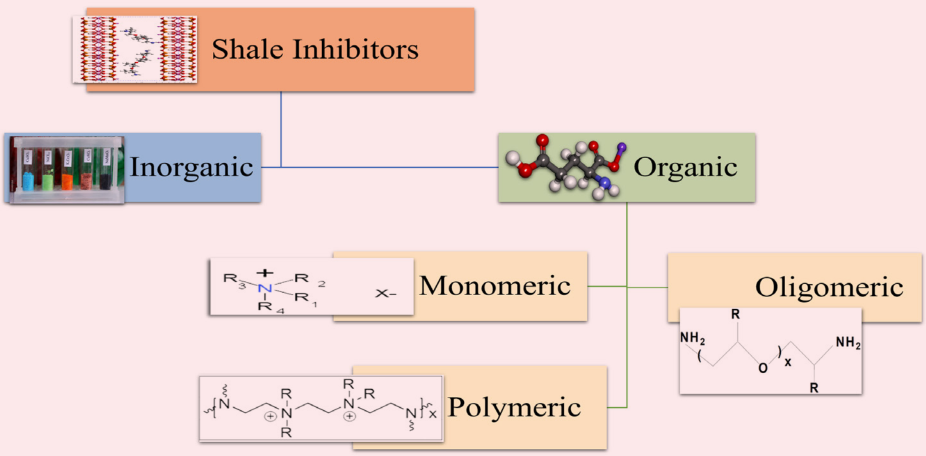
outcomes in difficult shale formations all over the world have been achieved thanks to significant advancements in the chemistry of shale inhibitors. To regulate reactive shales, various types of inorganic chemicals, such as salts, are traditionally added to drilling fluids or blended in completion brines. For many years, KCl has been the salt type that is most frequently suggested for inhibitory reasons[3].

Organic compounds are the most recent developments in the chemistry of shale inhibitors. These compounds were developed to replace salts in environmentally sensitive areas and improve the performance of the inhibitor additives. These compounds are divided into three main categories: monomeric, oligomeric, and polymeric amine shale inhibitors, depending on their structure and chemistry, Fig. 2.

A shale inhibitor can limit water entry through two primary mechanisms. One is when the cation present is exchanged for one that can increase the attraction between clay platelets, limiting the entry of water. Typically, this method includes adding salt, such as KCl, to the base fluid. Amine compounds are used widely to provide inhibition properties to water-based drilling fluids and completion fluids. These shale inhibitors, often referred to as clay stabilizers, react chemically on the surface of the shale or with the shale by entering the shale matrix through multiple or single cation-exchange mechanisms. These amine-based shale inhibitors are particularly effective when applied to shale with a high cationic exchange capacity[3].

Freitas et al. (2019)[4] found in his study that the utilization of fibrous lost circulation material added to the spacer, ahead of the cement slurry, presents excellent results for lost circulation scenarios and also improves mud removal results.

Fig. 2 *The classification of shale inhibitors.*



Mansour et al. (2021)[5] investigated the effects of adding surfactants to cement spacer. This study concluded that adding surfactants to the spacer design, particularly at high-density values, can help to reduce the problems with compatibility between oil-based mud (OBM) and the spacer. A spacer with a particular surfactant excelled over a spacer without surfactants in terms of mud displacement, cleaning performance, and rheology reading. Comparing all surfactant types, they discovered that anionic surfactant outperformed them all in terms of cleaning and displacing OBM.

Methodology

Cement Slurry Preparation Procedure

The slurry formulations were prepared in the lab using the standard API blender. The maximum speed used during slurry preparation was 12,000 revolutions per minute (rpm). The cement slurry components, described in Table 1, were mixed in the blender for 15 seconds at 4,000 rpm, and 35 seconds at 12,000 rpm[1, 6].

Cement Spacer Formulation

Two different spacers were formulated. Table 2 lists the formulation of the two spacers with the conventional KCl shale inhibitor and the novel amine, respectively. The defoamer, viscosifier, surfactant, and mutual solvent are commercial additives sold by service companies.

The following procedure describes how to formulate the spacer:

1. Add defoamer to the water at 1,000 rpm for 2 minutes.
2. Add KCl/novel amine to the water at 1,000 rpm and allow it to dissolve completely.
3. Adjust the blender speed to minimum speed, enough to get a vortex, while also preventing air entrainment.
4. Add the viscosifier stepwise to prevent fisheyes.
5. Allow the viscosifier to hydrate while varying the speed for 20 to 30 minutes to prevent vortex closure.
6. Adjust the speed to a minimum to get a vortex, add barite, and stir for 5 minutes.
7. Add the surfactant and stir for 5 minutes.
8. Add the mutual solvent and stir for 5 minutes.

Table 2 The cement spacer formulations.

Additive	Spacer 1 (g)	Spacer 2 (g)
Water	379.3	379.3
Defoamer	4.3	4.3
KCl shale inhibitor	19	—
Polyamine-based shale inhibitor	—	19
Viscosifier	2.9	2.9
Barite	604.7	604.7
Surfactant	26.8	26.8
Mutual solvent	38.5	38.5

Dispersion Test

The shale erosion test is used to measure the dispersive effect that a spacer will have on a specific type of shale. The following procedure was used for the shale erosion tests:

1. Prepare the shale cuttings that pass through a four-mesh sieve and are retained on a five-mesh sieve.
2. Add the cement spacer mud to the hot rolling cell and add 20 grams of four-mesh and five-mesh shale to the hot rolling cell and hot roll at 150 °F for 16 hours.
3. Recover the shale cuttings after hot rolling by pouring the spacer from the hot rolling cell onto the five-mesh sieve.
4. Wash the cuttings gently with 5% w/w KCl brine to remove the excess mud, remove samples gently, and place in an oven overnight to dry at 105 °F.
5. Weigh the sample and calculate the percentage of recovery based on the sample recovered.

Rheology

A fundamental governing aspect that ensures cement performance and helps determine the slurry's pumpability is cement rheology. A rotational viscometer was used in the rheological research to assess the apparent flow characteristics of a cement

*Table 1 The lead and tail cement slurry components. (*BWOC is by weight of cement.)*

Additive	Lead (101 pcf)	Tail (118 pcf)	Unit
Saudi cement G	100	100	%BWOC*
Water	425.7	353.1	gram
Defoamer	0.005	0.005	gps
Extender	1.8	—	%BWOC
Gelling agent	0.3	0.3	%BWOC
Retarder	0.1	0.1	%BWOC
Shale inhibitor	5	5	%BWOC

slurry at various temperatures in accordance with API criteria, including plastic viscosity (PV), yield point (YP), gel strength, etc.

The slurry was conditioned before being put into a viscometer cup that had been heated. Several shear rates were used to operate the viscometer. With the aid of the equipment's built-in software, the findings for PV and YP were measured. The sample on which the rheological properties were computed or another recently generated sample may be utilized to determine the gel strength. Slurries that have already been used are re-conditioned for 1 minute at 300 rpm to disperse gels. After the rotor was halted, the cement slurry was maintained stationary for 10 seconds inside the viscometer. When the rotation was resumed at 3 rpm after the initial 10 seconds, the initial gel or 10-second gel strength was calculated. The 10-second gel strength was given as the highest deflection. The cement slurry was then left in place for 10 minutes. The maximum deflection after restarting rotation at 3 rpm was recorded as the gel strength after 10 minutes[7].

Thickening Time Test

A standard API high-pressure, high temperature consistometer was used to determine the pumpability of the cement slurry. The consistometer was used to determine how long the cement will remain in the fluid state at downhole conditions. Thickening time is the time taken by the cement slurry to reach a consistency of 70 Bc. The cement slurry was poured from the blender into an API slurry cup, and was then placed in the consistometer. It was then subsequently subjected to the well conditions (temperature and pressure)[1].

Free Fluid Test

When the cement slurry is allowed to stand for a period prior to being set, water may separate from the slurry. The free water test is used to measure water separation using a 250 ml graduated cylinder in the cement slurry for 2 hours[1].

Results and Discussion

Dispersion Test Result

The shale dispersion test is a technique used to evaluate the reactivity of shale samples. It works especially well for finding potential inhibitors to utilize when drilling through shale formations. To compare the reactivity of shale samples with other fluids, we can use the dispersion test results for the shale samples, which are presented in Table 3 (with water, KCl, and with our novel polyamine).

The hot rolling and drying of the shale cuttings are shown in Figs. 3, 4, and 5. The amines performed well in the dispersion test, recovering 96.5% of the dispersed shales. This suggests

Fig. 3 *The shale after hot rolling and drying with water.*

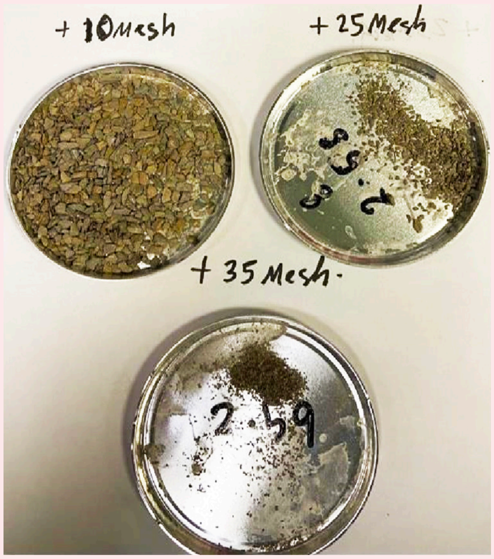


Fig. 4 *The shale after hot rolling and drying with KCl.*

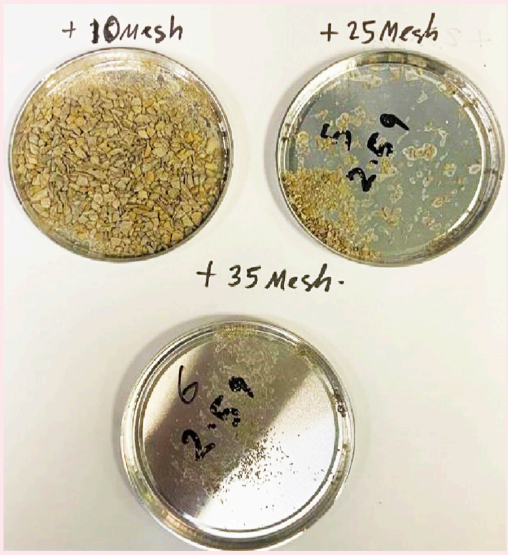
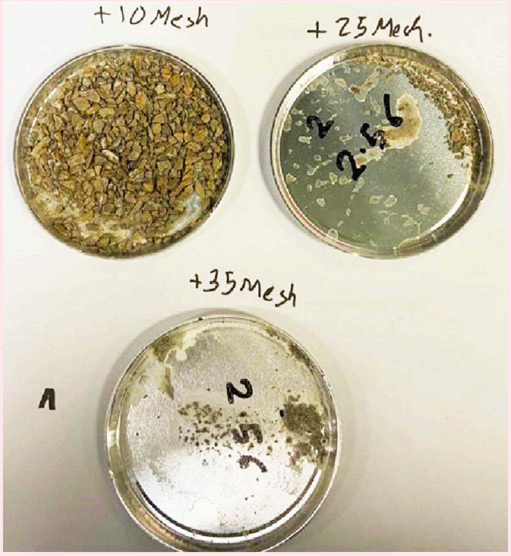


Table 3 *The dispersion test results for the shale sample.*

Sample	With Water	With KCl	With Novel Polyamine
Weight of the shale sample taken	20 g	20 g	20 g
Recovery after hot rolling at 150 °F, 100 psi for 16 hours wet	83.9%	82.0%	96.5%
Recovery after drying the shale for 20 hours at 150 °F	72.5%	70.4%	88.8%

Fig. 5 *The shale after hot rolling and drying with a polyamine shale inhibitor.*



that amines act as an excellent covering and protective layer, helping to keep the shale formation dry and reduce swelling. The new inhibited cement system with organic amine has a remarkable capability. Organic amines can be sequentially dispersed for longer lasting clay stability while cationic absorption occurs. Because of the unusual molecular structure of the organic amine, cations can enter clay platelets and bind them together. Subsequently, clays become incapable of absorbing water as a result, significantly stabilizing shale in the watery drilling environment[2].

Rheology of the Novel Cement System

To ascertain the cement pumpability, the PV and YP of the lead and tail cement slurry were determined at ambient temperature and at the bottom-hole circulating temperature (110 °F). The rheology results in Tables 4 and 5 demonstrate that the rheology parameters of our innovative inhibited cement system are within acceptable limits.

Thickening Time Test Result

A further investigation was done to measure the pumpability of the cement slurry by the consistometer. The formulated cement slurries were previously described in detail in Table 1 to investigate how our novel polyamine-based shale inhibitor will affect the thickening time. Based on the thickening time, the test results showed in Fig. 6 and Fig. 7 were 8 hours and 30 minutes, and 9 hours and 30 minutes for lead and tail slurry, respectively.

We may draw the conclusion that the novel amine-based shale inhibitor has no detrimental impact on the setting time. To put it another way, the shale inhibitor used in this study will provide us with the desired feature, namely the formation of a protective layer around the shales without altering the cement's properties or speeding up the setting profile, Fig. 8.

Compatibility Test Results of the Spacer with Mud and with Cement

To complete the performance assessment of the new creative spacer system and to effectively exhibit cleaning performance, a compatibility investigation between the new inhibited spacer and the mud was carried out. It is deemed to be compatible when the spacer and mud combination does not result in a strong gel or sludge and/or does not create continuous phase separation in the mixture[8]. The development of a strong gel may lead to an increase in pressure in the annular space downhole, which may, in the worst situation, result in the annulus becoming blocked[8].

Tables 6 and 7 provide the rheology measurements with a mixture of spacer and mud at various volume ratios suggested

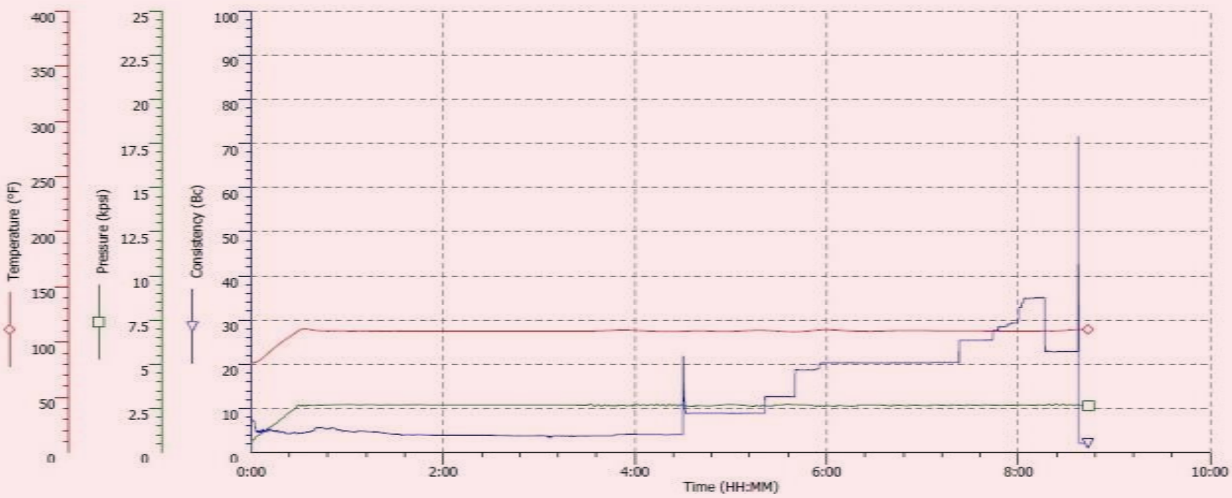
Table 4 *The rheology result for the lead cement slurry.*

Rheology Data						
Temperature	**Rheology at Room Temperature**			**Rheology at BHCT**		
Reading rpm	**Up**	**Down**	**Avg**	**Up**	**Down**	**Avg**
300	78	78	78	85	85	85
200	58	62	60	72	57	65
100	38	40	39	46	32	39
60	27	30	29	33	22	27
30	19	22	20	22	13	17
6	12	14	13	9	4	7
3	11	16	13	8	3	6
10 sec		13			3	
10 min		57			9	
Density			101 pcf			

Table 5 *The rheology result for the tail cement slurry.*

Rheology Data						
Temperature	**Rheology at Room Temperature**			**Rheology at BHCT**		
Reading rpm	**Up**	**Down**	**Avg**	**Up**	**Down**	**Avg**
300	78	78	78	98	98	98
200	69	99	84	84	84	84
100	68	96	82	68	67	67
60	68	94	81	61	60	61
30	68	93	81	55	55	55
6	5	85	45	28	33	30
3	5	64	34	15	20	17
10 sec		44			20	
10 min		61			29	
Density			118 pcf			

Fig. 6 *The thickening time chart for the lead slurry at 101 pcf.*



by API RP 10B to show compatibility between the two fluids. The two fluids are said to be compatible when the rheology of the mixture, whether it be spacer or mud, does not significantly differ from the rheology of the pure fluid. When the rheology value significantly increases in comparison to a pure fluid, such as a spacer, the mixture has gelled, which is undesired and incompatible[8].

The innovative inhibited cement spacer is compatible with the drilling mud and the cement slurry, as shown by the compatibility test results in Figs. 9 and 10.

Free Fluid Result

Since the lead and tail slurry is repeatedly subjected to high pressure and temperature for an extended period of time when pumped into a long horizontal part of the wellbore, a free fluid test was carried out to ascertain the thermal stability of the novel inhibited spacer. The results of the free fluid test, which are presented in Table 8, reveal great stability, no separation, and no free fluid volume.

Conclusions

Finally, the newly developed polyamine based inhibited cement system exhibits notable qualities and improved functionalities, such as:

1. The polyamine-based shale inhibitor performed well in the

Fig. 7 *The thickening time chart for the tail slurry at 118 pcf.*

Fig. 8 *The cement after the thickening time test for the: (a) lead, and (b) and (c) tail slurry.*

dispersion test, recovering 96.5% of the dispersed shales. This suggests that polyamine acts as an excellent covering and protective layer, helping to keep the shale formation dry, and reduce swelling.

2. The rheology characteristics and pumpability of the unique inhibited cement system are within standard perimeters.

3. According to the findings of the compatibility tests, the novel inhibited cement spacer is compatible with both cement slurry and drilling mud.

4. The thickening time test results prove that the novel amine-based shale inhibitor has no adverse impact on the setting time, neither accelerating nor retarding effect.

5. The innovative inhibited cement slurry system is highly stable, does not separate, and has no free fluid volume, which is demonstrated in the free fluid test result.

Acknowledgments

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Table 6 The compatibility test result for the spacer with mud.

Mud/Spacer (%)		Rheologies at 110 °F								
		300	200	100	60	30	6	3	PV	YP
100% Mud		96	81	64	58	47	32	27	64.49	38.68
95% Mud	5% Spacer	87	78	58	50	41	28	23	62.08	33.45
75% Mud	25% Spacer	79	68	45	38	29	18	16	63.40	22.03
50% Mud	50% Spacer	76	65	41	34	23	15	14	64.01	18.08
25% Mud	75% Spacer	73	62	37	30	19	13	12	63.68	14.78
5% Mud	95% Spacer	71	59	34	27	16	11	10	63.72	12.03
100% Spacer		72	60	35	28	16	11	10	64.76	12.26

Table 7 The compatibility test result for the spacer with cement.

Mud/Spacer (%)		Rheologies at 110 °F								
		300	200	100	60	30	6	3	PV	YP
100% Spacer		72	60	35	28	16	11	10	64.76	12.26
95% Spacer	5% Cement	72	60	35	28	16	11	10	64.76	12.26
75% Spacer	25% Cement	72	61	36	29	17	11	10	64.73	12.89
50% Spacer	50% Cement	74	62	37	31	18	12	11	65.37	14.03
25% Spacer	75% Cement	76	64	37	30	18	11	10	68.69	13.00
5% Spacer	95% Cement	78	65	39	31	19	10	10	70.63	13.22
100% Cement		80	66	41	32	20	11	10	71.82	14.01

Fig. 9 *The compatibility chart for the novel inhibited spacer with mud.*

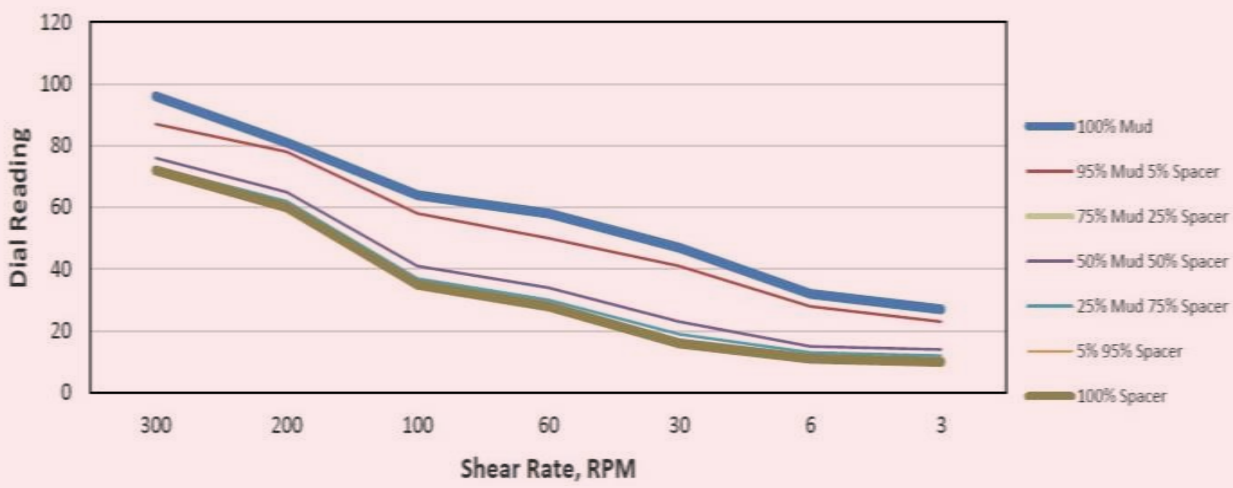

Fig. 10 The compatibility chart for the novel inhibited spacer with cement.

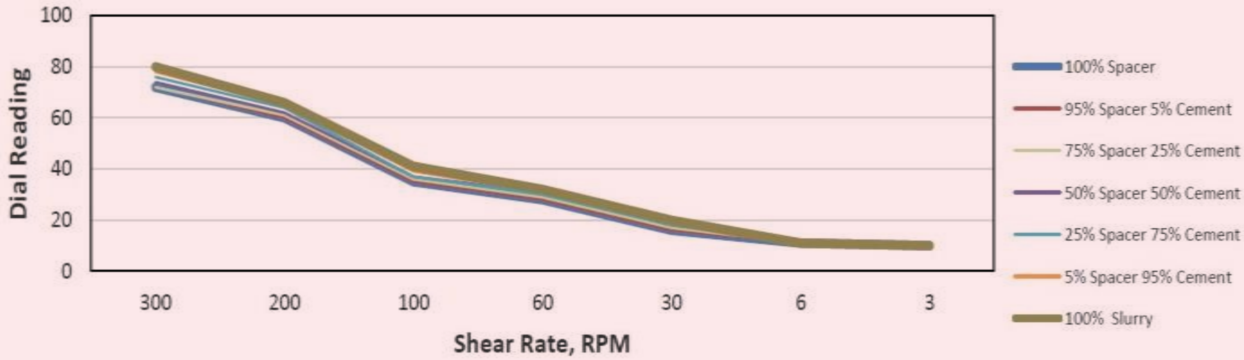

Table 8 The free fluid results for the lead and tail slurries.

Free Fluid Test Result		
	Lead	**Tail**
Slurry volume (ml)	250	250
Temperature (°F)	110	110
Test angle	45°	45°
Free fluid volume (ml)	0	0
Percentage of free fluid	0.00%	0.00%

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Ali is the coauthor of one Society of Petroleum Engineers (SPE) paper in the area of drilling fluids.

High Specific Gravity, Ultrafine Particle Size and Acid Soluble Manganese Tetroxide Succeeds in Replacing Heavy Brines as Completion and Workover Fluid

Ismaeel El Barassi Musa, Dr. Arthur Hale, Ahmed M. Ali, Mamdouh A. Elmohandes and Ibrahim M. Ali

Abstract /

A high-density completion and workover fluid (18 ppg to 20 ppg) was required for deep high-pressure gas wells. The traditional clear completion brines, which provide a solids-free environment to run and set downhole completion equipment were evaluated and were not approved as they came with an expensive price tag, and more importantly, they came with serious health, safety, and environmental concerns in addition to formation damage concerns.

The available alternative barite ($BaSO_4$) weighed water-based mud (WBM) was used as a completion fluid to set the lower completion; however, due to the concentration and size of the solids contained in this system, serious issues became evident. These included leaks due to poor sealing, string plugging, and stuck completions due to $BaSO_4$ settlement issues.

Manganese tetroxide (Mn_3O_4) was evaluated as an alternative to $BaSO_4$ as it has a higher specific gravity (SG) and a much smaller particle size.

To overcome all limitations of brines and $BaSO_4$ WBM, and achieve the required density for well control purposes, rigorous lab work was performed to formulate a completion and workover fluid with viscous sodium chloride brine. Additional density was achieved with the use of Mn_3O_4.

Mn_3O_4 has a very low sag index due to its ultrafine particle size. This small size eliminated the solids sag and settlement issues that were associated with the $BaSO_4$ weighed fluid and allowed for longer static fluid periods without the need to interrupt operations to circulate and condition the fluid. This saved a significant amount of time lost in sorting out all $BaSO_4$ sagging related issues in previous completion and workover operations.

This article presents laboratory design data and comparative data where this type of high-density fluid is used to successfully run lower completions and perform successful workover operations in gas wells without any problems.

Introduction

Commonly in the field of drilling oil and gas wells, once the reservoir section is drilled, a different phase of the well begins. Typically, the hole is displaced to completion fluid, which should have special characteristics and properties such as non-damaging to the reservoir with a proper density to keep the well under pressure control. If a high-density completion fluid (> 2.0 gm/cc specific gravity (SG)) is required, there will be challenges, which can include health, safety, and environmental concerns, high cost and operational robustness.

Replacing heavy brines with barite ($BaSO_4$) weighted water-based mud (WBM), has been shown to create significant issues ranging from formation damage to proper wellbore clean out procedures to $BaSO_4$ settlement. These two options — heavy brines and $BaSO_4$ laden fluids — required an effective alternative. An alternative safer fluid option is the use of manganese tetroxide (Mn_3O_4) weighted fluids.

Mn_3O_4 has been identified as a good alternate to $BaSO_4$ in weighted WBM with significant improvement in the overall fluids characteristics (plastic viscosity, fluid loss and filter cake quality and formation damage), thereby achieving many of the fluid key performance indicators while minimizing the significant risks of nonproductive time.

One of the major risks that has been associated with high-density solids weighted fluids is sag. Sagging is the term that describes the density variation of the fluids with a recordable change in the density while circulating the bottoms up, after tripping operations[1]. Drilling fluid companies initially responded to these challenges by utilizing micronized $BaSO_4$ as an alternative weighting agent. Micronized $BaSO_4$ has been used to help lower the equivalent circulating density (ECD) values for years. Subsequently, a non-$BaSO_4$ Mn_3O_4 weighting agent has proven to provide ECD values and anti-sag at a lower cost[2].

Studies have shown that small particles settle slower than larger sized particles. Density plays a role in settling, but not to the same extent as size. The tendency to observe either dynamic or static sag is lower with the utilization of weighting materials that have smaller particles[2]. Many operations have failed due to the combined problems that have been encountered, due to the usage of high-density fluids that contain a high concentration of relatively large size weighting materials, i.e., $BaSO_4$. Many factors have been identified and documented studying the tendency of oil field fluids to sag; however, the exact mechanism of the phenomena is still debated, but most of the industry experts believe there is a relationship between fluid rheology and the tendency to sag. Moreover, the exact rheological properties and measurement that indicate the propensity for sag are still not clear[2].

The studies and discussions about the sagging behavior of the solids' weighted fluids have concluded that the most important aspects for success is careful attention to the detailed planning before the initiation of the project and the close monitoring of those fluids during the execution stages. In particular, the recommendation that those studies came with were summarized in four main areas that need to be addressed to avoid the major risk of sagging: (1) well planning, (2) fluid properties and testing, (3) operational practices, and (4) operations monitoring at the well site[1].

Most of the publications that looked at the fluid behavior in high-pressure, high temperature wells had concluded that the main challenges include fluid rheology control, weighting material sagging tendencies, as well as polymer performance and corrosion[3,4]. These concerns along with the large environmental impact and safety issues at the high costs associated with most heavy brines options suggests that an alternative safer fluid option is needed.

The use of the Mn_3O_4 weighted fluids has been identified as the most reasonable selection to overcome all of these risks and concerns, and achieve the desired target of having safe and effective operations, especially in offshore environments.

Mn_3O_4 Features and Benefits

One of the most common uses of Mn_3O_4 in the industry is as a weighting agent in cement slurries and in some extended reach wells where $BaSO_4$ sag is an issue — especially in nonaqueous fluids. This weighting agent is spherical with a submicron particle size, and a SG of approximately 4.8. The spherical shape has been shown to be beneficial to maintain relatively low plastic viscosity values in drilling fluids[5].

As reported in the literature, the major characteristics of the Mn_3O_4 can be summarized with the following main points:

- An "inert" weighting agent.
- A red-brown powder.
- Not milled from natural ores, but man-made.
- Spherical particles.
- Surface area = 2 to 4 m^2/g.
- D50 < 1 micron.
- Density = 4.8 SG (15% higher than $BaSO_4$).

Physical Properties of Mn_3O_4 in Comparison with $BaSO_4$

The physical and chemical property comparison supports the use of smaller spherically shaped higher density particles in fluids, Table 1, and Figs. 1, 2, and 3.

Chemical Properties for Mn_3O_4

1. Solubility (water): Insoluble/slightly soluble.
2. Solubility (organic solvents): Insoluble/slightly soluble.
3. Materials to avoid: Strong hydrochloric (HCl) acid. Reacts violently with hydrogen peroxide.
4. Hazardous decomposition products: Strong HCl acid reacts with Mn_3O_4 forming toxic chlorine gas under certain conditions.
5. Solubility with glycolic acid:
   - 4 wt% dissolved 75 wt% Mn_3O_4 particles at 190 °F.
   - 5 wt% had removal efficiencies of 85% to 90% of Mn_3O_4 based filter cake after 20 hours of soaking.

Field Implementation and Operational Challenge

A gas well was identified for workover operations. The well developed a leak on the tubing retrievable subsurface safety valve (TRSSSV). The goal of the workover operation was to replace the leaking TRSSSV with a new valve.

This plan had special challenges requiring a kill weight of 17 ppg to 18 ppg (~127 pcf to 135 pcf) fluid to be used as a barrier to suspend the well while nippling down the production tree and nippling up the blowout preventer (BOP). To de-complete the well, circulating holes were punched in the tubing and the tubing casing annulus (TCA) displaced to the kill fluid as a part of controlling the well pressures before proceeding with cutting and pulling the old tubing string to change the faulty valve.

The plan to change out the leaking valve had several major risks, such as the high possibility of severe to total losses during the operations of bullheading — breaching the upper completion seals. The second risk was identified as the need of a second barrier in the TCA during the extended operations of removing the production tree and installing the BOP. This need for a second barrier required a fluid with good suspension characteristics so no change in fluid pressure gradient takes place over time. This was required to avoid any possible gas migration to the surface and prevent debris from plugging the lower production string. This will require additional coil tubing work to clean the lower completion from those settlements and restore the well productivity after the workover work was completed.

Table 1 The material's physical properties; a comparison between $BaSO_4$ and Mn_3O_4 (Courtesy of Elkem AS).

Property	$BaSO_4$	Mn_3O_4
Density (gm/cm^3)	4.2	4.8
Mean particle diameter (µm)	15 – 20	0.5
Hardness (Moh's scale)	3.0 – 3.5	5.0 – 5.5
Abrasive (Relative scale)	1	0.3
Shape	Angular	Spherical
Sag factor	0.56	0.51

Fig. 1 The material's physical properties comparison graph (Courtesy of Elkem AS).

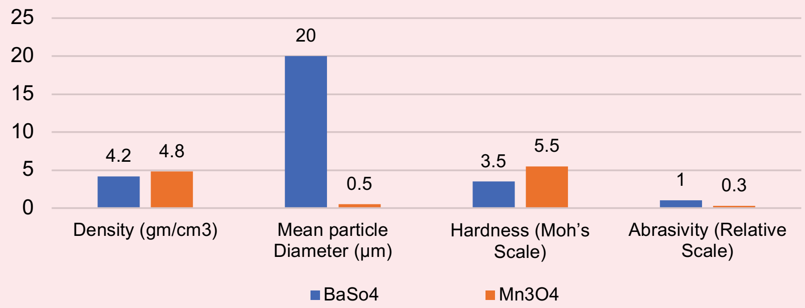


Fig. 2 The material's sag factor comparison graph (Courtesy of Elkem AS).

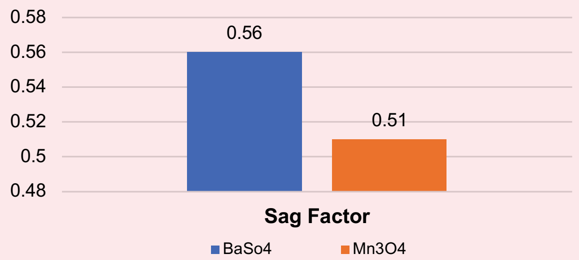
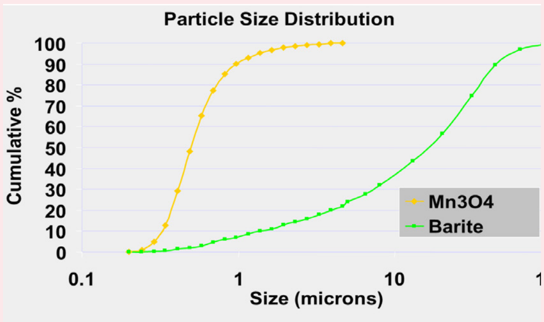


Fig. 3 The material's particle size comparison between $BaSO_4$ and Mn_3O_4 (Courtesy of Elkem AS).



Discussing those risks and the possible mitigations, a carefully designed fluid that utilizes Mn_3O_4 as the weighting material was formulated to have the proper density and suspension characteristics given the temperature profile of the well and the long period needed for the fluid to remain uniformly suspended.

Fluid Formulation and Customization

Extensive formulations testing in the laboratory was conducted to study the rheological and solids settlement trends of these formulations both before hot rolling (BHR) and after hot rolling (AHR) to simulate the downhole conditions that the fluid will be exposed to, in addition to monitoring and recording extended sag outcomes, over a period of 504 hours of static aging.

The main goal of the formulation was to minimize the fluid solids content, matching the operational needs and tools limitations to have low solids content for logging and perforating tools that are planned to be used to punch and cut the old tubing with solids settlement that can hinder operational progress.

Building on the basic physical properties of the Mn_3O_4 with a SG of 4.8 and small particle size a base fluid of sodium chloride and sodium bromide mixture was chosen to get the basic fluid up to 11 ppg to 11.5 ppg (82.3 pcf to 86 pcf). Although a little more expensive, this base fluid had the added advantage of lowering the solids content and keeping the percentage of suspended solids at the minimum possible ranges.

Pre-hydrated industrial bentonite flocculated with pH sources was used as the main source of viscosity in the fluid to avoid the temperature limitation of xanthan gum polymer. A small amount of xanthan gum was used to provide initial low shear rheology control.

Two different density ranges were formulated and hot rolled for 16 hours under 270 °F to simulate actual bottom-hole temperature; both formulations showed excellent sag factors at 270 °F for up to 504 hours. Once the formulation testing was concluded and field formulation was approved, the fluid was mixed in an offshore mixing facility.

Field Execution Challenge

The well was killed by bullheading seawater followed by 1,100 barrels of polymer mud weighted by $BaSO_4$ to assure that all percolated gases in the tubing has been pushed back to the reservoir and the well is secured. The specially designed workover fluid was pumped to cover the volume from the surface to the top of the lower completion string.

An isolation retrievable plug had been set at the top of the lower completion string. The old tubing was punched using wireline and confirmed the communication with the TCA before pumping continued to displace the calcium bromide brine in the annulus. Once the displacement was completed and confirmed, the fluid was circulated for three full circulations to ensure the fluid was homogeneous. Once the targeted parameters had been achieved, circulation was stopped, and a mechanical cutter was run into the well to cut and retrieve the old tubing. Once completed, the production tree was rigged down and the BOP was nippled up.

This operation required static fluid conditions under downhole temperature and pressure for over 280 hours. As soon as the BOP was nippled up and tested, circulation was established before proceeding with pulling the old tubing string. Circulation was established without any issues with no change in the drilling fluid's density at bottoms up and during the circulating time. The entire operation was deemed successful with the well production rate coming back on at the same rate recorded before shutdown.

This remarkable success has encouraged the team to plan other wells that require complicated workover operations with the same approach and fluid type. Currently, two wells are undergoing the same process with the same expected results achieved on the subject well. Subsequently, full data on those wells are not available at this time to include in this article, nevertheless, the progress is identical to the results discussed in this article.

Lab Testing and Results

When the samples had been collected from a completion fluid, which was weighted up with $BaSO_4$, Table 2, failed for the extended static periods — since the sag factor exceeded 0.53 as shown in the lab test — it was mandatory to reformulate a fluid that can sustain those periods.

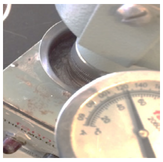
Detailed lab testing had been carried out to optimize and finalize the formulation that could achieve those required operational key performance indicators. Table 3 illustrates the

Table 2 *The sagging test for the $BaSO_4$ formulation.*

Formulation 1: 127 pcf – 17 ppg			
Hours	**Top**	**Bottom**	**Sag Factor**
48	1.73	1.74	0.501
96	1.7	1.8	0.514
144	1.7	1.82	0.517
192	1.65	1.83	0.526
240	1.62	1.85	0.533

Formulation 2: 132 pcf – 17.6 ppg			
Hours	**Top**	**Bottom**	**Sag Factor**
48	2.09	2.19	0.512
96	2.11	2.21	0.512
144	2.07	2.27	0.523
192	2.04	2.27	0.527
240	2.04	2.34	0.534

Table 3 *The reading of the rheological properties of the workover fluid formulated using Mn_3O_4.*

Rheology	Formulation 1 BHR	Formulation 1 AHR	Formulation 2 BHR	Formulation 2 AHR
	125 pcf – 16.7 ppg		132 pcf – 17.6 ppg	
Temperature (°F)	120	120	120	120
600 rpm	119	79	125	100
300 rpm	76	52	78	65
200 rpm	57	42	59	51
100 rpm	36	30	40	36
6 rpm	13	12	20	16
3 rpm	11	11	18	15
10 s gel (lb/100 ft²)	19	14	20	17
10 min gel (lb/100 ft²)	109	36	148	60
30 min gel (lb/100 ft²)	157	46	300	72
PV (cP)	43	27	47	35
YP (lb/100 ft²)	33	25	31	30
The picture proves fluid homogeneity and no proof of strange, coagulated particles being formed.				

rheological outcomes of the formulation BHR and AHR for 16 hours, simulating the shearing of the fluid under the expected downhole pressure and temperature.

The testing objective mainly focused on recording the rheology of both formulation 1 at 125 lb/ft^3 (16.71 ppg) and formulation 2 at 132 lb/ft^3 (17.6 ppg). Table 4 shows the corrected solids percentage as 13.34% and 16.44%, respectively, demonstrating the lower solids content when compared to the $BaSO_4$ polymer mud. The lower solids content, where the rheological profile and the small size of the Mn_3O_4 demonstrated an outstanding sag result for formulations 1 and 2. This was conducted with significant density requirements at 270 °F.

In Table 5, the timeline for sag testing has been extended to demonstrate that the fluid is stable for several hours at temperature.

Conclusions

Engineered solutions met the required balance between the lower cost, environmentally friendly, and safer applications to assure operational excellence. A formulation of a WBM that utilizes Mn_3O_4 as a weighting material, was engineered to overcome the environmental risks and high cost associated with utilizing heavy brines that are commonly used in well completions and workover operations.

In addition, the work addressed the operational risks associated with the utilization of traditional weighting materials such as $BaSO_4$ that may cause problems such as sagging and formation damage due to its physical and chemical characteristics. It was proven in one of the most challenging workover operations that the use of Mn_3O_4 as a weighting material in a WBM formulation showed success in terms of sag resistance for extended static conditions reaching 504 hours with no circulation at high temperature. The fluid performed flawlessly at downhole temperatures and pressures while executing the workover operation.

Acknowledgments

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Table 4 *The solid's analysis of the tested formulation.*

Retort WBM with Sodium Bromide	Formulation 1 – 16.7 ppg	Formulation 2 – 17.6 ppg
Vol% water	66.66	63.26
Vol% solids	33.34	36.74
Vol% solids corrected	13.34	16.44
Water ratio	100	100
LGS% by vol	1.15	1.18
HGS% by vol	12.19	15.26
LGS (ppb)	10.44	10.76
HGS (ppb)	205.15	256.71

Table 5 *The extended sag testing results for formulations 1 and 2, supported with sample pictures for the samples tested.*

Sag Factor	**Formula 1 (96 hours)**	**Formula 1 (168 hours)**	**Formula 1 (336 hours)**	**Formula 1 (504 hours)**	**Formula 2 (96 hours)**	**Formula 2 (168 hours)**	**Formula 2 (336 hours)**	**Formula 2 (504 hours)**
Separation (ml)	0	8	38	44	3	9	40	42
Layer 1 (SG)	2.0086	2.006	2.05	2.061	1.68	2.111	2.157	2.168
Layer 2 (SG)	2.0088	2.016	2.069	2.092	2.118	2.124	2.199	2.219
Layer 3 (SG)	2.009	2.024	2.09	2.106	2.130	2.138	2.205	2.235
Layer 4 (SG)	2.031	2.036	2.015	2.112	2.136	2.144	2.236	2.251
Layer 5 (SG)	2.032	2.04	2.115	2.118	2.155	2.179	2.246	2.270
Layer 6 (SG)	2.034	2.046	2.121	2.134	2.160	2.18	2.250	2.275
Sag Factor	0.502	0.505	0.508	0.509	0.509	0.508	0.510	0.512

Photos ASA

Formulation 1 (96 hours)

On the bottom

Formulation 1 (504 hours)

Formulation 2 (96 hours)

On the top

Formulation 2 (504 hours)

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Ismaeel El Barassi Musa is a Petroleum Engineer working in the Advanced Technical Services Division of Saudi Aramco's Exploration and Petroleum Engineering Center – Advanced Research Center (EXPEC ARC) as a Research Science Consultant. He began work in the Drilling and Workover organization from 2008-2015, then worked as a Senior Drilling Fluids Specialist with the Drilling Technical Department, and the Upstream Professional Development Center (UPDC), where he developed and taught drilling fluids related courses to drilling engineers.

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CO_2 Foamed Fracturing Fluids for High Temperature Hydraulic Fracturing

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Abstract /

Carbon dioxide (CO_2) foamed fracturing fluids injection can assist water conservation during hydraulic fracturing. Moreover, foamed fracturing fluids offer an attractive alternative over conventional stimulation fluids, particularly in stimulating water sensitive formations, the need for a shortened flow back period, and energizing created fracture geometry. The thermal stability of foam at high temperatures is one of the main challenges. In this article, a CO_2 foamed acrylamide-based terpolymer fracturing fluid was developed for high temperature application.

The foam viscosity development depends on the type of gas, foam quality, external phase fluid viscosity, foaming agent and foam stabilizers. Rheological properties of nitrogen (N_2) and CO_2 foams containing acrylamide-based terpolymer were measured at high temperatures, i.e., 300 °F to 350 °F, and a shear rate from 100 1/s to 500 1/s. A circulating flow loop foam rheometer was used to measure the rheological behavior of foamed fluid prepared using linear gel. Foam stability improvement using nanoparticles was also demonstrated.

The viscous character of the external phase of the foam plays a significant role in the viscosity of foam. In this article, water and linear gel prepared using a 35 ppt acrylamide-based terpolymer has been studied at 75% foam quality and two different temperatures. A 75% quality foam viscosity having water as the external phase gave 70 cP with N_2 and 31 cP with CO_2 at 100 1/s, whereas the viscous linear gel gave 146 cP with N_2 and 64 cP with CO_2 at 100 1/s studied at 300 °F. After increasing the test temperature to 350 °F, there was a significant drop in viscosity noticed. The thermal stability of foam can be improved by the synergetic effect of surfactant and nanoparticles. The foam half-life was delayed from 5.5 minutes to 9.1 minutes after the addition of silica nanoparticles using water as a base fluid.

Viscous properties of the fracturing fluids influence the fracture geometry and capability of transporting proppant into the fracture. Based on available literature reports, the rheological properties of foamed fracturing fluids are limited to 300 °F. This article reveals the rheological properties of CO_2 foamed fracturing fluids in a temperature range of 300 °F to 350 °F, and therefore helps to design a fracturing treatment to stimulate reservoirs with high temperatures.

Introduction

Foam is an emulsion of a dispersed gas phase into an external liquid phase stabilized using a surfactant or foaming agent. Foamed fracturing fluid offers distinct advantages, such as good proppant transport, solid-free fluid loss control, minimum fluid retention due to the low water content of foam, compatibility with reservoir fluids, and low hydrostatic pressure to returned fluids enabling faster cleanup[1].

For carbonate reservoirs, the use of foamed acid for fracture acidizing was studied in laboratories and fields during the 1970s[2]. Foamed acid offers additional benefits over non-foamed acids, such as acid retardation, more profound conductivity generation, and improved acid diversion. During matrix acidizing, foam diverts acid from the high permeability regions into the low permeability regions[3].

Schramm (2000)[4] defined surfactants as short-chain fatty acids that are amphiphilic or amphipathic, i.e., they have one part that has an affinity for nonpolar media and one part that has an affinity for polar media. These molecules form oriented monolayers at interfaces and show surface activity. Based on the nature of the polar head group, surfactants are divided into anionic, cationic, amphoteric, and nonionic categories. Most commonly, an anionic surfactant, e.g., sulfated alkoxylate, a nonionic surfactant, e.g., ethoxylated linear alcohol and an amphoteric surfactant, e.g., betaine is used as foaming agents in foam fracturing[5].

A suitable surfactant that is thermally stable is crucial while designing foam treatment. High temperatures can decompose the surfactant present in the foam, reducing the surfactant concentration in the bubble lamellae. This reduced surfactant concentration eventually causes destabilization of the bubble as there is not enough surfactant to spread on the bubble film and "heal" the lamella (Marangoni effect) that stresses have weakened. In addition, the temperature does accelerate the liquid drainage in the lamella, gradually causing a decrease in the film thickness, and therefore, bubble destabilization[6].

Foam is characterized by mainly three parameters: quality, texture, and rheology[7]. Foam quality, % (Γ) at a given temperature and pressure, is determined using the following equation:

$$\Gamma = \frac{100V_g}{V_g+V_l} \quad (1)$$

where V_g is gas volume, and V_l is liquid volume.

The foam texture refers to the bubble size distribution of the dispersed gas phase. Qualitatively, it describes the distribution of small/large bubbles and how homogeneous/heterogeneous mixtures are. Foams normally form in systematic hexagonal texture as a result of gas dispersion through a continuous surfactant solution[8]. Harris (1989)[5] studied the effect of texture on the rheology of foam fracturing fluids, and it was concluded that the higher the shear rate, the pressure and surfactant concentration produces finer texture foams.

Different investigators reported on rheological models of foam fluids[9]. Almost all reports suggested that foams are non-Newtonian fluids. As some foams behave like pseudo-plastic fluids, others behave like Bingham plastic. The apparent viscosity of foams is measured by measuring shear stress at a varying shear rate. Apparent viscosity is found to decrease as the quality decreases and is not dependent on the bubble size, but on the bubble size distribution[10]. Most commonly, the foam exhibits properties of Power Law fluid[7].

In the 1970s, polymer-based foam fracturing fluids were used to stimulate the production of hydrocarbons from low-pressure and low permeability wells. Initially, guar-based polymers prepared linear gelled foamed fracturing fluids[11]. With the increased use of linear gelled foamed fracturing fluids, crosslinking agents were added to improve the viscous character of fluids for high temperature wells. In the 1980s, borate and titanate crosslinked guar nitrogen (N_2) foam fracturing fluids were developed for high temperatures up to 300 °F, where a significant increase in foam viscosity was observed after crosslinking the linear gel. The introduction of carbon dioxide (CO_2) foams for deeper and hotter formations offset the need for stable N_2 foam. The CO_2 reacts with water in the foam to form carbonic acid, which decreases the overall pH.

Al-Muntasheri et al. (2016)[12] reviewed the use of nanoparticles for enhanced waterless fracturing. Emrani and Nasr-El-Din (2015)[13] used iron(III) oxide and silicon dioxide nanoparticles with 50 nm and 100 nm diameters, respectively, to enhance the stability of foam formed by CO_2 and an alpha-olefin sulfonate (AOS) surfactant. Prigiobbe et al. (2015)[14] studied the synergic effect of nanoparticles and surfactants on the foam texture and the effective gas viscosity during transport in a porous medium. Particle stabilization is influenced by particle size, shape, concentration, contact angle, and interactions between particles.

In this article, the performance of a coiled flow loop viscometer was validated by comparing rotational and pipe viscometer results. The stability of N_2 and CO_2 foams containing acrylamide-based terpolymer linear gel and water were measured at 300 °F and 350 °F. The use of nanoparticles to stabilize CO_2 foam was also demonstrated using a foam half-life measurement and foam texture.

Experimental Methods

Materials

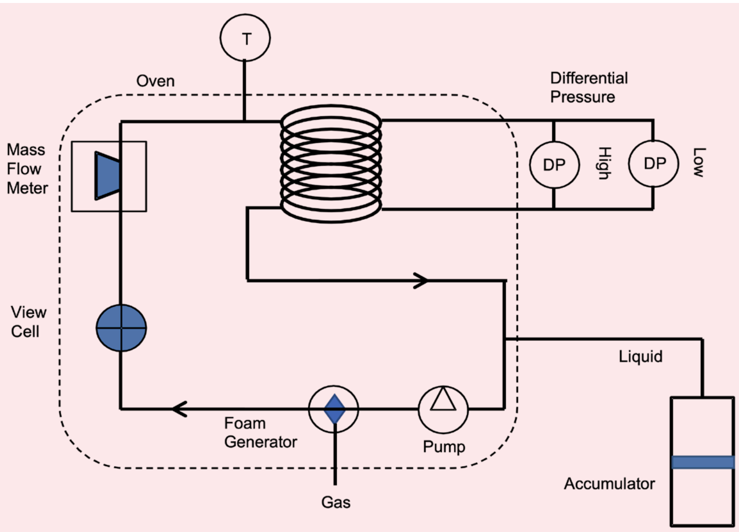
The linear gel was prepared using 35 lb/1,000 gal acrylamide-based terpolymer in deionized (DI) water. The foaming agent used was amphoteric surfactants and the nanoparticles sample was silica, with a 7 nm size. N_2 and CO_2 gas were used from a cylinder having 99.5% purity. A booster pump was used to set the required test pressure and get supercritical CO_2.

Foam Rheology Testing

A circulating loop foam rheometer with a helically coiled, 10 ft long tube with a 0.25" inside diameter was utilized in this stability study of N_2 and CO_2 foamed linear gel at 300 °F and 350 °F. A 75% foam quality was adjusted and maintained for all foamed tests in this article.

Figure 1 shows a schematic of the circulating loop foam rheometer. A 300 shear rate was applied while maintaining the

Fig. 1 *A schematic of the circulating loop foam rheometer.*



foam quality and it was dropped to 100 1/s to measure foam stability. The viscosity of foam was calculated using the ratio of shear stress to shear rate. The fluid is pumped at a constant rate across the coiled loop where the rate is used to calculate the shear rate, and differential pressure across the coil is used to calculate the shear stress.

A required quality foam inside the flow loop was generated by replacing the liquid with gas. The gas is inserted inside the flow loop in the foam generator while maintaining a constant system pressure.

Foam Half-Life Measurements

To study the synergetic effect of surfactant and nanoparticles, a dynamics foam analyzer (DFA-100) from Kurss Scientific Instruments was used. The test solution was prepared by adding the required quantity of surfactant and nanoparticles sample in DI water.

The foam was generated by bubbling CO_2 in a glass column through porous support. The CO_2 gas rate was optimized to 300 cm^3/minute to get maximum foam height. Foam height decay was measured using a camera system connected to the data acquisition system.

Comparison of Rotational and Pipe Viscometers

The rheological measurements of fracturing fluids are commonly done by couette-type viscometers, also known as rotational viscometers. The measurement fluid is contained within the annular space or shear gap between the rotor and bob. The rotor is rotated at a known rotational speed measured as revolutions per min (rpm), and with the used rotor/bob geometry, the shear rate is calculated. The viscous force exerted by the fluid creates a torque on the bob and with the used bob geometry shear stress is calculated.

The viscosity is calculated using the ratio of shear stress to shear rate. In the case of a pipe viscometer, the fluid is pumped at a steady rate, and the differential pressure across the pipe is measured. Table 1 shows the equations to calculate shear rate and shear stress using different types of viscometers.

Table 1 *The shear rate and shear stress equations used in different types of viscometers.*

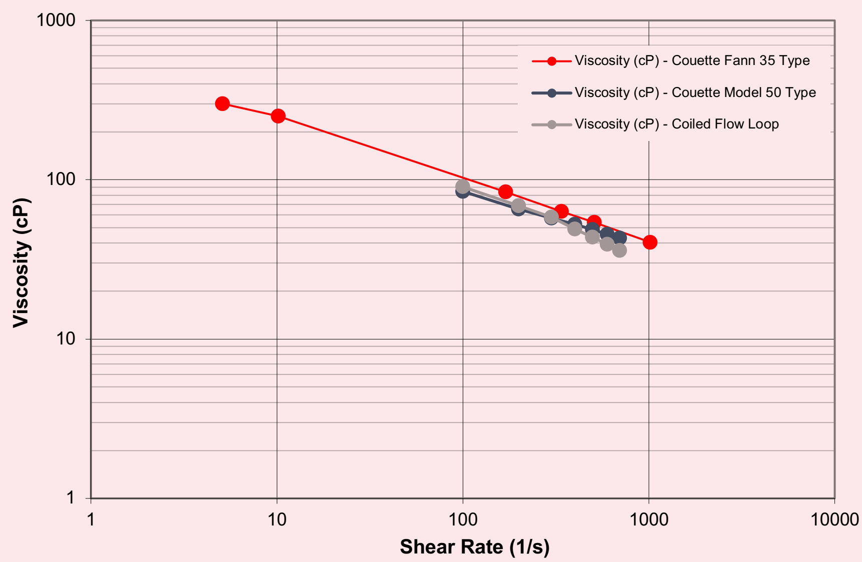
	Couette Fann 35 Type	Couette Model 50 Type	Pipe Viscometer
Shear rate	$k_3.N$	$k_3.N$	$\frac{8V}{D}$
Shear stress	$k_1.k_2.\theta$	K.T	$\frac{D\Delta P}{4L}$

The Fann 35 type rotational viscometer is most used in the field to perform a quality assessment of gel. The Model 50 type rotational viscometer is used as pre-lab testing before field jobs to design fluid systems under high-pressure, high temperature (HPHT) conditions. A pipe viscometer is commonly used to analyze slick water performance where friction is evaluated at a high rate, low pressure and low temperature.

In this article, a helically coiled flow loop is used to measure the viscosity of both non-foamed and foamed fracturing fluid. Table 1 shows the pipe viscometer expressions that were used to calculate the viscosity using a coiled flow loop, where k_1 = torsion constant, dyne-cm/degree deflection; k_2 = shear stress constant for selected bob surface (1/cm^3); k_3 = shear rate constant for selected rotor-bob combinations (1/s per rpm); T = digitally measured torque (dyne.cm); K = multiplying factor for selected bob geometry (1/cm^3); V = velocity (cm/sec); D = tube inside diameter (cm); ΔP = differential pressure across flow loop (psi); and L = length of the flow loop (cm).

Figure 2 shows the viscosity of the 35# linear gel measured at room temperature using different types of viscometers. The

Fig. 2 *The viscosity of the 35# linear gel was measured using different types of viscometers.*



viscosity measured using two couette/rotational viscometers and a pipe/coiled flow loop follows the Power Law model. The viscosity of the rotational viscometer showed slightly higher viscosity than the pipe viscometer.

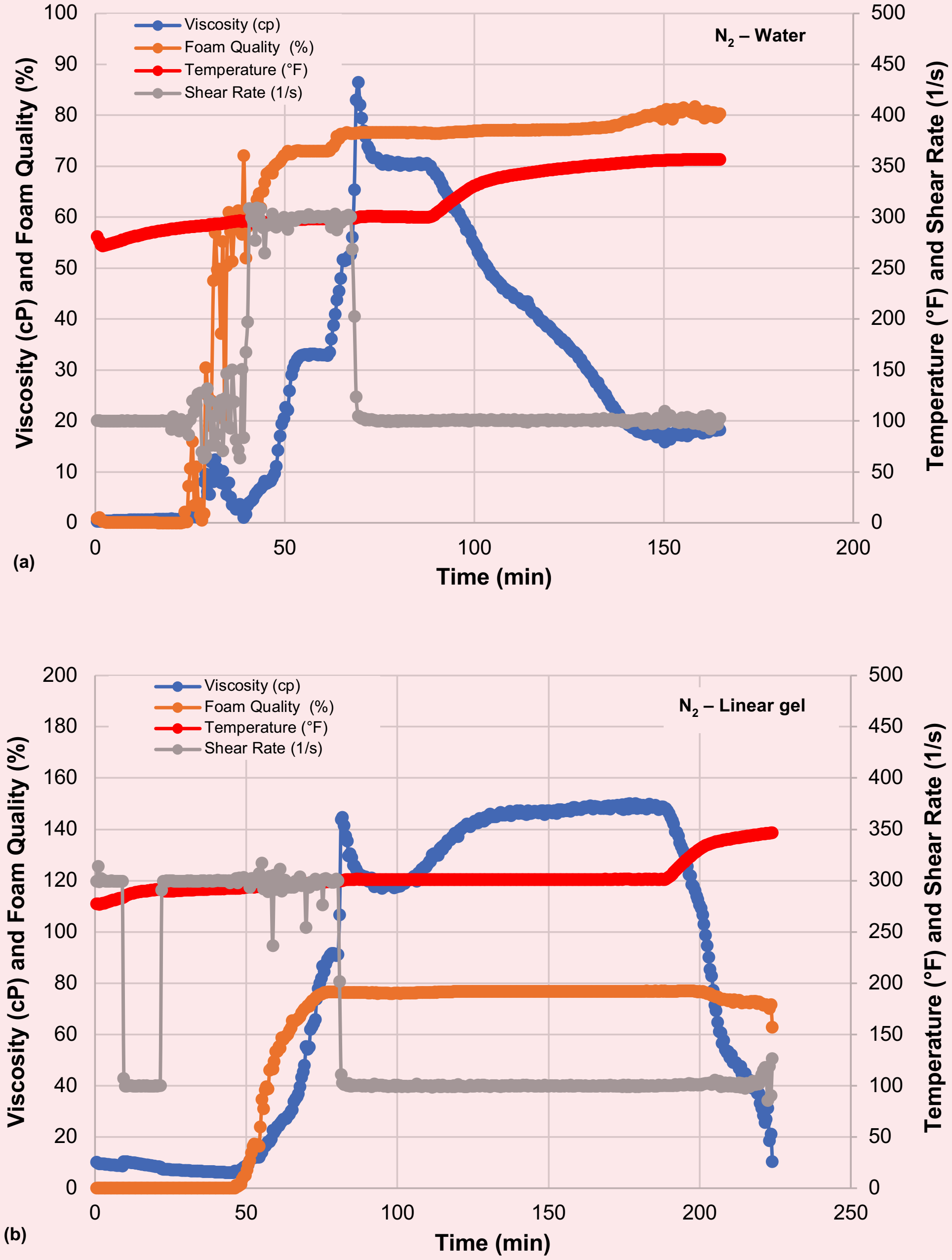
Knoll (1985)[15] reported a similar observation where the rotational viscometer showed higher viscosity due to the slipping effect. This surface phenomenon creates the possibility of the fluid not adhering to the bob or cup of the viscometer, which shows slipping at the wall of the bob or cup.

The viscosities measured using a Model 50 type viscometer at 100 1/s to 300 1/s were closely matched with a coiled flow loop and slightly deviated at a higher shear rate. This validates the use of a coiled flow loop showing similar viscosities as the Model 50 type rotational viscometer. In the coiled flow loop, the addition of foaming capability made it possible to measure foam rheology under HPHT conditions, which we cannot do with a rotational viscometer.

Foam Rheology

Foam rheology is a time-dependent viscosity measurement governed by the external phase of the two-phase fluids system. A flowing foam will attain an equilibrium texture, which depends

Fig. 3 The N_2 foamed viscosity was measured at 2,000 psi and 300 °F to 350 °F for (a) N_2-Water, and (b) N_2-Linear gel.



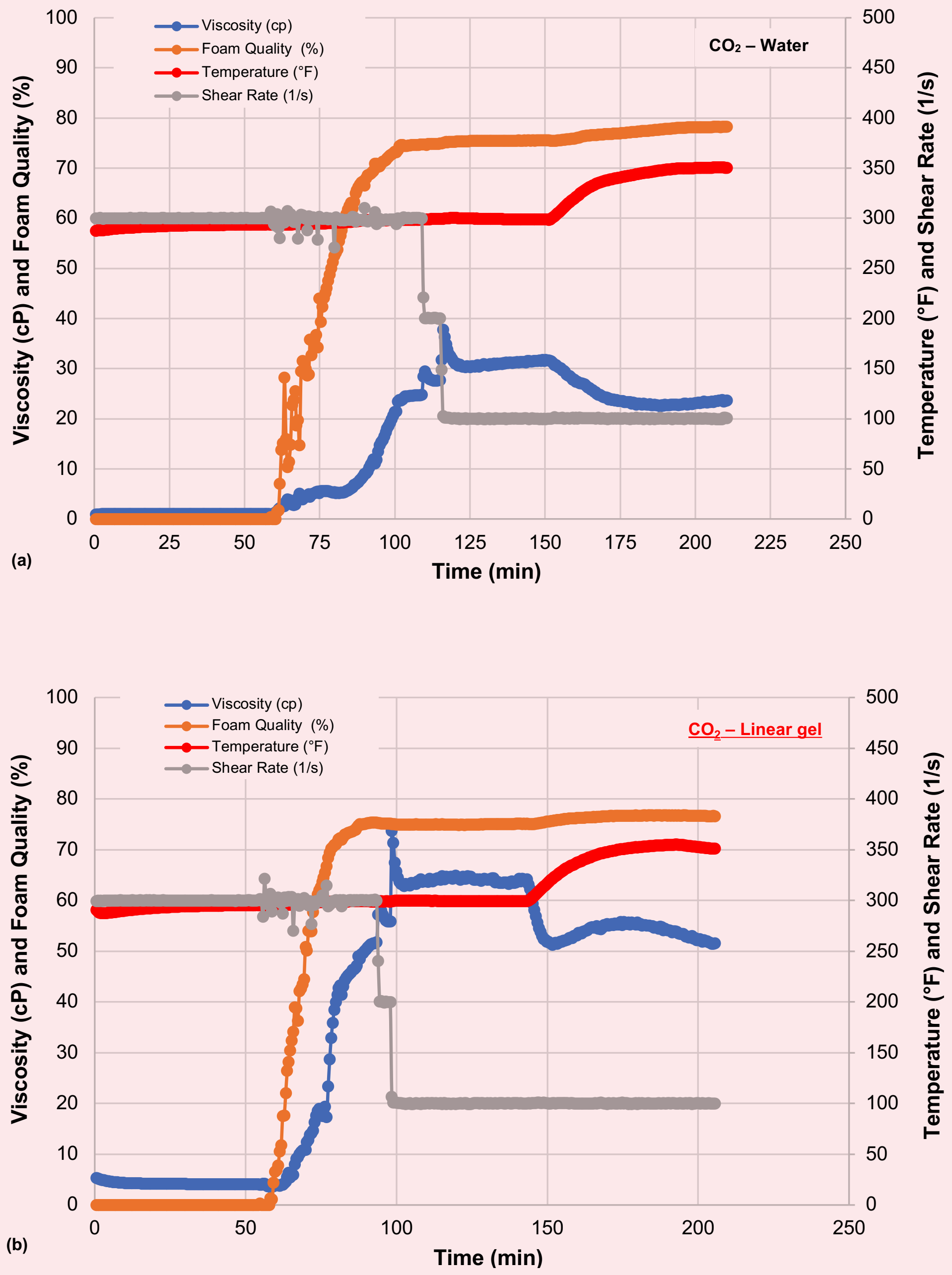
on the shear rate, temperature, pressure, and viscosity of the external phase. Interactions between different forces caused by surface tension, viscosity, inertia, and buoyancy produce a variety of effects in foams[16]. These effects include different bubble shapes and sizes, anomalous effects due to slippage, buoyancy, and inertia forces on the foam destroy the discrete bubble structure, which makes the foam dynamically unstable.

The foam rheological measurement provides the structural stability of foam to optimize the surfactant/stabilizer concentrations. The viscosity of foam was calculated using the Power Law model. Most commonly, N_2 and CO_2 are used as gas phases, while water-based fracturing fluid is used as the liquid phase. The following sections analyzed N_2 and CO_2 foam stability using water and 35 lb/1,000 gal, an acrylamide-based polymer linear gel.

N_2 Foam

The properties of N_2, including its relative inertness, low solubility, compressibility, and other advantages, are well documented in the literature[17]. The low viscosity N_2 gas can propagate more easily into very small pores and microfractures, which helps in transmitting the injection pressure to get low breakdown pressure. It is also demonstrated that N_2 gas can generate more

Fig. 4 The CO_2 foamed viscosity was measured at 2,000 psi and 300 °F to 350 °F for (a) CO_2-Water, and (b) CO_2-Linear gel.



fracture complexity to improve productivity[18].

The N_2 foamed viscosity was prepared using water and 35 lb/1,000 gal of an acrylamide-based polymer linear gel having a 1% (vol/vol) foaming agent in both. A 76% foam quality was achieved with water using N_2 while shearing fluid at 300 1/s, 2,000 psi, and 300 °F, Fig. 3a. After foam stabilization, the shear rate was dropped to 100 1/s and kept constant throughout the test. The viscosity of the generated foam was stabilized and measured to be 71 cP at 100 1/s. Because of increasing the temperature to 350 °F, the viscosity decreased significantly from 71 cP to 18 cP under the same conditions, Fig. 3b.

Therefore, an approximate 75% decrease in viscosity was observed because of the thermal degradation of foam. In the case of linear gel, a foam quality of 77% was achieved using N_2 while

Fig. 5 The foam stabilization using the synergetic effect of (a) surfactant, and (b) nanoparticles.

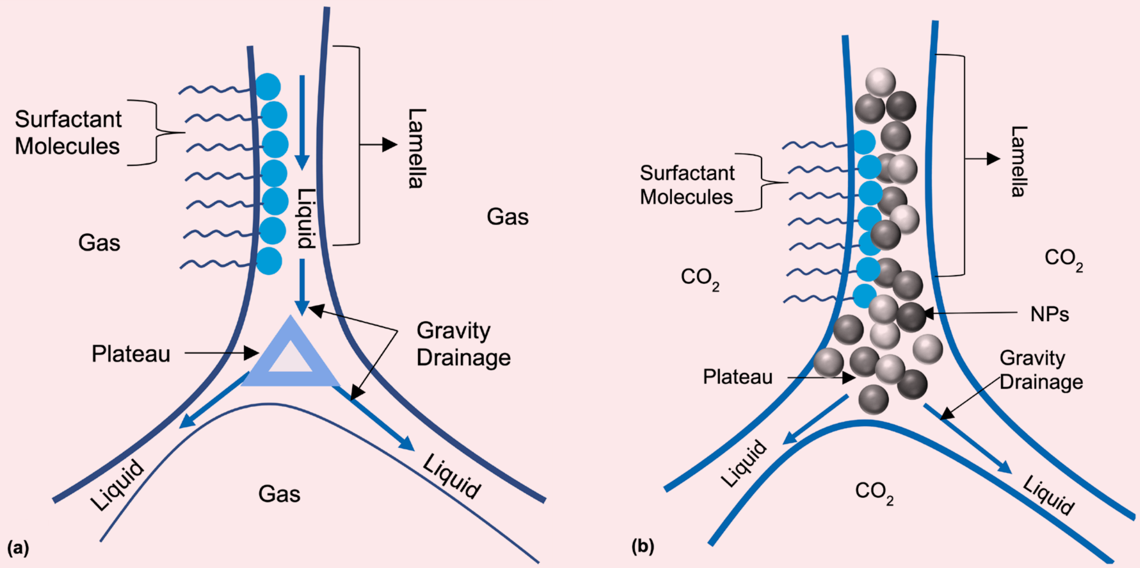


Fig. 6 The foam half-life comparison with and without nanoparticles.

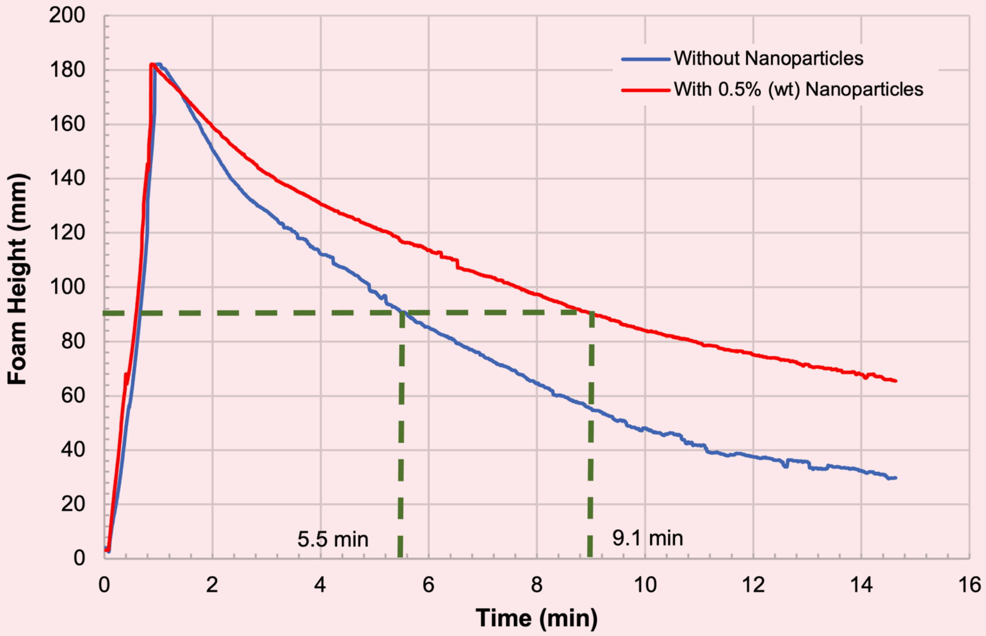
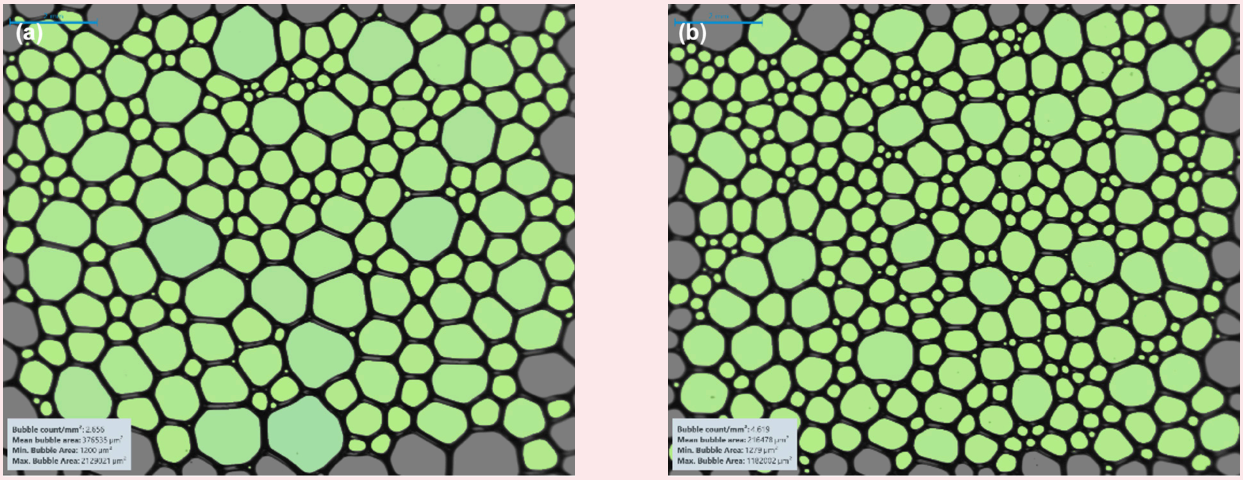


Fig. 7 *The foam texture captured after 3:20 min:sec while measuring the foam's half-life: (a) Without nanoparticles — bubble count/mm² = 2.656, and (b) with nanoparticles — bubble count/mm² = 4.619.*



shearing fluid at 300 1/s and 300 °F. After foam stabilization, the viscosity of the foam was stabilized to 149 cP at 100 1/s. After setting the bath temperature to 350 °F, a continuous decline in viscosity was observed and the viscosity was unstable and dropped below 20 cP at 100 1/s.

At extreme temperatures, the foam quality also dropped suddenly showing an unstable condition of foam. Using different viscosity fluids, i.e., water and linear gel as an external phase of foam, an increase in viscosity was observed.

CO_2 Foam

Under fracturing conditions, CO_2 is in supercritical status and flows like gas with liquid-like densities. The CO_2 solubility increases with pressure and solvent nature, which helps to form a homogeneous mixture of fracturing fluid. CO_2 can be transported at a liquid, non-cryogenic temperature and pumped with conventional equipment in liquid form. Upon heating to reservoir temperature, it expands to reservoir pressure and vaporizes to the gaseous state. The gaseous CO_2 can assist in the flow back and cleanup post-fracturing. Another valuable benefit of liquid/supercritical CO_2 is its high density of approximately 1.014 SG during injection, which helps gain hydrostatic pressure. Other benefits of CO_2 include lowering interfacial tension and clay inhibition[19].

The CO_2 foamed viscosity was prepared using water and 35 lb/1,000 gal of an acrylamide-based polymer linear gel having a 1% (vol/vol) foaming agent in both. A 75% foam quality was achieved with water and linear gel using CO_2 while shearing fluid at 300 1/s, 2,000 psi, and 300 °F, Fig. 4a. After foam stabilization, the shear rate was dropped to 100 1/s and kept constant throughout the test. The viscosity of the generated foam was stabilized and measured to be 31 cP at 100 1/s and decreased to 23 cP with an increase in temperature to 350 °F, Fig. 4b.

A similar decrease in viscosity trend was observed in the case of linear gel. The viscosity dropped from 64 cP to 55 cP because of temperature effects. The viscosity of CO_2 foam showed lower than N_2 in the case of both external phases, water and linear gel. This could be because of the condensability of CO_2 gas to liquid CO_2. At 2,000 psi and 300 °F, CO_2 becomes a supercritical liquid, enhancing solvation properties.

Foam Stabilization Using Nanoparticles

The thermal stability of foam at high temperatures is one of the main challenges. The gas-liquid interface of foam tends to collapse with temperature. The stability of CO_2 foam greatly depends upon the optimum hydrophilic-lipophilic balance of surfactants. Using nanoparticles in addition to a surfactant gives synergetic effects to stabilize foam under harsh conditions of temperature and salinity, Fig. 5a. Nanoparticles can assist in overcoming liquid drainage, decreasing the CO_2 gas diffusion rate, and minimizing the rupturing of foam at high temperatures, Fig. 5b.

To study the synergetic effect of the surfactant and nanoparticles, an amphoteric surfactant and silica nanoparticles were used. Figure 6 shows the decay in foam height measured with respect to time measured using a dynamic foam analyzer. A series of experiments were conducted to optimize the CO_2 gas rate to 300 cm³/minute to form foam in the glass column and decay in the foam was measured using a camera system connected to the data acquisition system. The foaming agent/surfactant concentration — 1 vol% — was kept constant in both tests and 0.5 wt% of silica nanoparticles was used in DI water to study the effect of the foam's half-life under atmospheric conditions. The test without nanoparticles measured 5.5 minutes to decay the foam height to 50%. Using nanoparticles, the foam half-life was improved to 9.1 minutes, showing better stability for foam.

While measuring the foam's half-life, after 3:20 min:sec, a foam picture was captured using a camera system. Using image processing software, the number of bubbles per mm² area without nanoparticles was measured to 2.656, Fig. 7a. In the case of the test conducted with nanoparticles, the number of bubbles per mm² area was increased to 4.619, Fig. 7b. This shows a smaller bubble foam texture, leading to improved foam stability.

Conclusions

Hydraulic fracturing using CO_2 foamed fracturing fluids presented in this article offers freshwater conservation, faster and more efficient flow back recovery and improved hydrocarbon recovery due to CO_2 miscibility with reservoir fluids. Based on lab investigations, the following conclusions can be drawn:

- Viscosity comparison of rotational and pipe/coiled loop flow viscometer validates the use of a coiled flow loop to measure foam rheology under HPHT conditions.
- N_2 foam viscosities for both water and linear gel as a base fluid showed higher viscosity than CO_2 because CO_2 behaves like a gas, but has liquid-like densities. Under test conditions, CO_2 was tested as the supercritical liquid.
- We increased the viscosity of the external phase of foam, i.e., from water to linear gel; viscosity was increased more than twice in both N_2 and CO_2 foam.
- The synergetic effect of the surfactant and nanoparticles showed enhancement in foam stability and texture.

The viscosity of foamed fracturing fluids can be tailored by adjusting the CO_2 foam quality to meet specific fracturing design targets for different bottom-hole static temperature wells and the compatibility with other stimulation additives. Foam stability using nanoparticles and increasing in an external phase viscosity by crosslinking linear gel need to be explored to enhance viscosity for proppant fracturing.

Acknowledgments

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Concurrently, his hydraulic fracturing research explores the use of CO_2 as a fracking agent, striving to reduce water demand and pollution by stabilizing CO_2 foam using functionalized nanoparticles. Both areas of Mohammed's research emphasize environmental considerations in the pursuit of more efficient fossil fuel extraction processes.

He received both his B.S. and M.S. degrees in Chemical Engineering with honors from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia.

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Use to thank those who helped make the article possible.

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Ghadeer M. Alsulami, Dr. Shouxiang M. Ma, Katrina Cox and Allen Britton

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Beyond API: How to Evaluate Industry Standards for Practical Applications Improving Cementing Fluid Designs and Testing Accuracy

Joseph M. Shine Jr. and Kirk Harris

Abstract / A standard can represent the foundational instruction for performing any task consistently and enabling repeatable results. Laboratories as well as personnel can apply the practices and techniques documented in standards without the knowledge of the intent — how it relates to managing the risk at the well site and achieve the execution success. Within standards there can be instructions, which have resulted from field experience, helping to improve the representative test conditions in the laboratory to overcome risks previously identified.

Innovative Approach to Enhanced Well Integrity Evaluation in Unconventional Completions with Fiberglass Casings

Ali A. Hijies, Fauzia R. Waluyo, Kamaljeet Singh and Abderrahmane Benslimani

Abstract / More wells are being completed with fiberglass casings to overcome the challenge of corrosion to the carbon steel casings. A fiberglass casing is expected to increase the longevity of the wells. The wells completed with fiberglass still require the operators to confirm that the casing is in good condition and also the annular cement sheath is able to provide mechanical support and zonal isolation. The evaluation poses a challenge as the properties of the fiberglass are very different to that of the carbon steel casing. Some studies were performed in 2018 to test the ultrasonic physics in fiberglass; this article will describe the challenges and how we have now developed an innovative data acquisition, processing, and interpretation workflow to properly evaluate both the fiberglass casing condition as well as the annular cement condition.

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