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Performance analyses of hydroxyethyl cellulose (HEC) polymer as gelling agent in gravel-pack carrier fluid formulation for sand control of hydrocarbon production wells

ABSTRACT

This study considers the performance of 40ppt and 60ppt hydroxyethyl cellulose (HEC) polymer used as a gelling agent in the formulation of carrier fluids for gravel pack transport in sand control operations in oil and gas wells. The gravel pack carrier fluid was prepared by adding adequate amounts of sodium persulfate (SP) used as gel breaker, Fe-2 used as an iron control agent, KCL brine as mixed fluid, K-35 used as pH buffer, BE-6, and BE-35 used as biocides, HEC used as a gelling agent, and distilled water. The effects of temperature, gel loading, and breaker fluid concentration on the rheology, gel break time, and sand settling of the formulated HEC carrier fluid were considered. The results showed that shear stress, plastic viscosity and yield point and consistency factor decreased with an increase in bottomhole temperature for both 40ppt and 60ppt HEC gels. Furthermore, flow behaviour index was observed to be within the range of 0.45±0.1 40ppt and 0.5±0.04 for 60ppt HEC of gel loading, respectively and showing shear-thinning characteristics. Good gravel settling was observed for the HEC gels when in contact with gravel, addition of breaker fluid greatly improved the sand/gravel suspension for 40ppt and 60ppt gel loadings. Gel break time of the HEC gel increased with increasing gel loading, and at higher breaker fluid concentrations, HEC gel degradation becomes more critical as temperature increases. The results highlight the adequate performance of HEC polymer as gravel pack fluid in sand control operation.

Keywords: *Carrier fluid, HEC, Sand control, Breaker fluid, Gravel pack*

1. INTRODUCTION

Sand production during the production of oil and gas from reservoirs is a global problem that has severe consequences on petroleum field development. Sand production occurs mostly in unconsolidated reservoirs and poses serious threats to the productive life of the reservoir and/or well [1]. Sand production results when the stress exerted on the formation exceeds the strength of the formation causing failure of the rock. The rock fails due to tectonic activities, overburden pressure, pore pressure, drilling-induced stress, and drag force occasioned by the producing fluid. Sand production is most prominent in sandstone formations and unconsolidated sandstones have generally compressive strengths less than 6.9 MPa [2].

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Moreover, sand production is caused by high-rate production. An increase in the production rate from the reservoir increases the drawdown pressure between the reservoir pressure and the wellbore flowing pressure causing higher frictional pressure forces that may rise to exceed the compressive strength of the formation and cause sand particles to be broken down and detached from the bulk formation [2]. Owing to these, most wells are produced below a calculated critical flowrate which is below the frictional pressure force, and not above the compressive strength of the formation [2].

The problem of sand production can be mitigated by effective sand control methods. Effective sand control is significantly imperative to avoid operational challenges including casing or tubing wear, erosion and damage of downhole and surface equipment, casing collapse, environmental problems associated with sand disposal, and expensive workover operations [3] which ultimately results to decreased well productivity alongside increased well operational costs.

The most common method of sand control available in the industry to maximize hydrocarbon involves installing a device downhole that acts as a mechanical barrier and excludes sand particles from entering the wellbore. Some of these methods include gravel pack methods and the use of standalone screens such as slotted liners, pre-pack screens, wire-wrapped screens, expandable sand screens, etc. Gravel pack is the most common and utilized mechanical sand control method. It applies to both cased-hole and open-hole completions. However, open-hole gravel packing in unconsolidated formations is most common [4].

Gravel packing is the filtration of formation sands or fines from entry into the wellbore through the use of prepacked screens or screens/slotted liners packed with gravel, placed into the casing or liner in the annulus [5]. For gravel packing to be accomplished, functional carrier fluids are required [6]. These fluids do the work of gravel (proppant) transport from the surface to desired depth in the wellbore. The selection and design of carrier fluid are imperative in achieving a good and successful gravel pack [7]. Certain unique properties are required of the carrier fluid, these include adequate gravel suspension and transport capability, adequate fluid loss or leak-off, good rheology, adequate stability, proper viscosity reduction control, controllable break, and minimal formation damage [8].

In the past, brine-based carrier fluids were used to transport gravel during gravel packing commonly called conventional gravel packing. These fluids have been used to some degree of success [9]. For instance, brine-based carrier fluids have been reported to be inhibitive to water-sensitive zones which give the wellbore adequate stability periods from the onset of the displacement of the brine during gravel pack and well completion phases. However, advancement in drilling and completion which led to the emergence of maximum reservoir contact wells such as highly deviated, horizontal, and extended reach wells require carrier fluids that have much-enhanced properties such as lubricity, rheology, temperature-stability, etc [9].

Gravel pack carrier fluids have been broadly classified into which are water packing and slurry packing techniques. In water packing, low-gravity fluids typically brine is used [10]. This technique typically relies on the fluid velocity occasioned by a high fluid pump rate to achieve the transportation of low-gravel concentration fluids to the annulus. It requires tight annular proppant packs which are, however, susceptible to high leak-off rates in permeable zones leading to sand bridging and causing poor gravel pack jobs [10]. The water-pack technique is characterized by a high tendency for intermixing the gravel (proppants) with the formation sands which reduces the gravel pack efficiency [10].

Meanwhile, slurry packing uses viscous fluids. These fluids having relatively higher viscosity transport high gravel concentrations to the wellbore or annulus based on their viscous properties [6]. Slurry packing techniques permit pumping at low rates and as such achieves more gravel transport to the perforations [11]. Reduced rate and time of pumping reduces significantly the operational costs of the pumping process. Slurry packing reduces the chances of the gravel intermixing with the formation sands due to the increased concentration of gravel in the transported material. Despite its merits, slurry packing is not without its limitations. A high tendency for formation damage and non-uniform packing exists for slurry packing due to the use of polymers [12].

The viscosity agents used in the formulation of slurry packing carrier fluids are classified using their viscosification. These viscosity agents include the polymeric fluids and the non-polymeric fluids due to their use of polymeric and non-polymeric fluids as viscosifying agents respectively [3]. For polymeric fluids, polymers such as random-coil and helical polymers are utilized in the carrier fluid formulation. The random-coil polymers include guar, hydroxypropyl guar (HPG), and hydroxyethyl cellulose (HEC). The Random-coil polymers are susceptible to high viscosity loss at high temperatures. The helical polymers which are more thermally stable include xantham, welan gum, diutan, and scleroglucan [7]. However, xantham, HEC, and viscoelastic surfactant (VES) are most commonly investigated.

HEC has been widely applied as carrier fluids in gravel pack placement due to its good gravel transport, good rheological properties easy-to-break and cost-effective, and low formation damage potentials. However, HEC has been reported to offer adequate gel strength to aid the effective transport of gravels in highly deviated wells or long well intervals which commonly cause premature sandouts [5]. Xantham has been selected in gravel transport during sand control operations due to its adequate proppant suspension capacity at relatively low polymer loading, good rheology, insensitivity to salinity, good thermal stability, mechanical shearing resistance, excellent fluid loss/leak off rate and hydrates in most pH range and low formation damage potential. However, it is expensive, and its use leads to cost constraints [13].

This study presents the experimental analyses of the use of Xantham and HEC as gravel pack carrier fluids during sand control operations in an open-hole sandstone formation in a Niger Delta field in Nigeria.

2. SAND PRODUCTION AND CONTROLS IN OIL AND GAS WELLS

Sand production and control have become an interesting topic in oil and gas. Production engineers are specifically faced with the challenges of understanding and managing sand control problems for efficient good productivity

2.1. Sand Production

During fluid production, the nature of the reservoir makes it susceptible for formation sands to be produced alongside the reservoir fluids commonly called sand production [14]. Sand production causes decreased production rates alongside increased operational/processing costs. Furthermore, there is the challenge of wear of the production equipment and surface-coating of vessels. Sand production is typically caused by high-rate production such that the formation stress is exceeded by the production-induced stress [15]. Generally, stress is caused by Tectonic actions, overburden pressures, and pore pressures. However, stress changes result from drilling, and drag forces on producing fluids which alter the original stress distribution and balance in the formation [2]. Stress changes in the formation alter the cementing capacity of the natural materials in the sand grains, thus allowing the movement of sand grains into the wellbore. The Niger Delta is an area noted with high sand production potential.

Figure 1 shows the mechanism of sand production during the production of hydrocarbons.

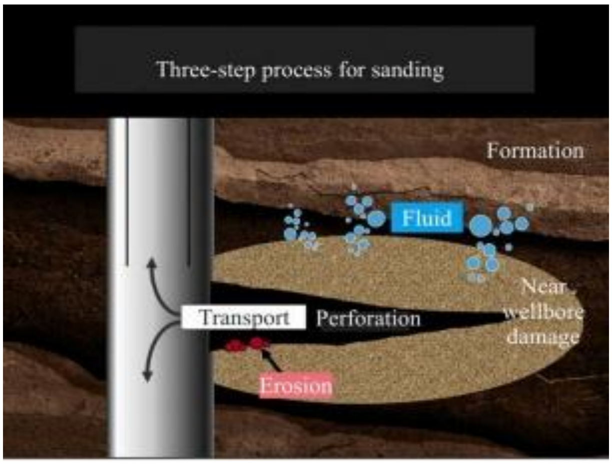

Figure 1. Mechanism of sand production [2]

Slika 1. Mehanizam proizvodnje peska [2]

Figure 1 describes the three-step mechanisms of sand production comprising near wellbore damage, perforation and transportation.

As a result of low production velocities, sand settles in the wellbore and covers the section of the reservoir close to the wellbore causing near-wellbore damage. This sand builds up if not removed and decreases the production rate [2].

2.2. Sand Control

There are various methods applied to achieve sand control during hydrocarbon production from reservoirs. These methods broadly include mechanical, chemical, and combination methods

Mechanical methods utilize devices that create barrier systems and act as semi-permeable membranes placed along the flow line permitting only the passage of reservoir fluids but excluding the passage of formation sands [16]. The efficiency and effectiveness of this method are determined by the grain size of the formation sand, the gravel, and the screen slot widths. Gravel packing (open-hole and cased-hole), frac packs, stand-alone screens, wire-wrapped screens, and expandable sand screen methods amongst others are some of the various mechanical sand control methods that are available [2].

Chemical control involves the use of chemicals such as resins which are injected into the formation to enhance its strength through the cementation of the collapsing/collapse grains of sand. The resins utilized are phenolic, furan, and epoxy resins due to their wide commercial availability. These chemicals when injected into the formation form a wall of stable and consolidated sand grains around the surface of the casing. Chemical control methods require multiple stages to implement which include acid cleaning, pre-flush, and injection of the resin and catalyst [17]. Clay presence inhibits the process of cementation, hence pre-flushing to is done to get rid of clay particles using a clay stabilizer. Combination methods are a combination of both mechanical and chemical methods and utilize both gravels and chemicals [18].

In gravel packing, several factors affect the long-term performance of the gravel pack, this includes the purity of the gravel, pore spaces of the pack, and the stress generated in the process. These factors depend on the correct selection of gravel, carrier fluids, placement technique, etc.

2.3. Gravel Pack Carrier Fluids

Gravel pack fluids are used to transport proppants or gravels to desired depth in the wellbore for sand control. Some of the most utilized gravel-packed fluids include brine, Xantham, HEC, VES, etc. The carrier fluids selection depends on its ability to meet the following conditions: adequate fluid loss to ensure compact packing of gravel, complete break at the required time leaving no residual solids in the formation to minimize formation damage, compatibility with the formation and wellbore fluids with low frictional pressure to avoid fracturing the formation when there is a narrow margin between pore pressure and fracture gradient [11].

2.3.1. Brine

Brine-based solutions applied as gravel pack fluids have been an age-long practice in the oil and gas industry. The use of these fluids is commonly described as conventional gravel packing or water packing. These fluids have been applied especially to alpha-beta (α-β) gravel packing. Although there have been demonstrated degrees and a history of success using brine-based carrier fluids, it has inherent challenges. Brine-based carrier fluids are significantly limited to shale-free formations [18]. Such formations would not hydrate and destabilize the openhole with brine carrier fluids. However, shale-free formations are not common among the prevalent oil and gas reservoirs. To prevent wellbore destabilization and other wellbore-related issues during proppant transport higher viscosity fluids are employed in gravel packing techniques known as slurry packing [18].

2.3.2. Hydroxyethyl Cellulose (HEC)

As a polymer used in carrier fluid preparation, HEC offers low formation damage, good gravel transport, good rheological properties, cost-effectiveness, and ease to break. However, its lack of gel strength makes it less desirous when applied to the transport of gravels in highly deviated or long well intervals which ultimately results in premature sandouts [5]. HEC, although water-soluble is synthesized from water-insoluble cellulose and ethylene oxides. There have been major improvements in the synthesis process of HEC like the mixing procedure, and the shearing and filtration processes; which have eliminated precipitation in the fluid due to incomplete hydration of the polymer.

2.3.3. Xantham

Xanthan gum is a natural heteropolysaccharide of heavy molecular weight obtained from *Xanthomonas campestr*is that undergoes bacterial fermentation. Xantham is characteristically preferred due to its good proppant suspension capacity at relatively low polymer loading, good rheology, insensitivity to salinity, good thermal stability, mechanical shearing resistance, excellent fluid loss/leak-off rate, and hydrates in most pH ranges. Additionally, some grades of xanthan gum maintain their stability even up to 176.7^{o}C [13]. Xantham has good gel strength which makes it preferred for gravel packing in highly deviated wells or long intervals. However, it has a high potential for damaging formation. This challenge can be tackled by improving the manufacturing processes and the availability of equipment to mix, shear and filter the polymer [7].

2.3.4. Viscoelastic Surfactant

Unlike polymers, VES induces viscosification as the result of the formation of aggregates commonly called micelles from the association of the surfactants. Its stability depends on the surfactant used to create it [5]. the use of VES as carrier fluids leaves behind no filter cake on the wellbore wall, hence they are non-wall building fluids. However, VES carrier fluids are characterized by higher fluid leakage into the reservoir matrix than polymeric carrier fluids

2.4. Other Additives

There are other additives applied in the formulation of carrier fluids for gravel packing. These include salts, biocides, surfactants, iron-chelating agents, acids, bases, breakers, etc. The salts function as clay stabilizers and aid in the increment of the weight of the mixed water for well control. Biocides aid in the elimination of bacteria that might infect polymetric materials. Moreover, iron chelating agents prevent gel crosslinking and the formation of iron precipitates. Surfactants help in the reduction of the surface tension of the fluid system, while the pH of the fluid is adjusted by the use of buffer solutions. These generally ensure polymer dissolution, hydration, stability, and break in the fluid system [7].

Gel breaker addition is mainly done at the surface to reduce the viscosity of the fluid downhole and achieve adequate well clean-up. The gravel pack placement process could be jeopardized due to premature sand outs when the carrier fluids break too early. It is required that breaking occurs at the required time to provide allowance for complete packing in the entire interval thus eliminating damaging effects on the formation permeability. Some of the commercially available gel breakers are oxidizers, acids, and enzymes. Temperature, type, and concentration of breakers, type, and concentration of polymer, and pH are vital as they affect the gel breaker reaction [7].

From studies on the effect of breaker concentration, breaker type, crosslinker, and pH of guar/cellulose-based fracturing fluids, Almond [19] showed that after break the resulting residual polymer can plug the formation and reduce the flow of fluids

According to Powell et al. [20], the optimal performance of biopolymer viscosifiers such as Xanthan is attained when the minimum critical polymer concentration (CPC) is reached. Several factors such as the type of fluid and wellbore conditions such as temperature, average shear rate, shear history, salinity, velocity gradients, hole angle, polymer configuration, polymer size, density, and concentration of suspended solids.

2.5. Description of some tests conducted for gravel pack carrier fluids

Carrier fluids are tested for various properties during experimental analyses, some of these are discussed below

2.5.1. pH

The pH of the carrier fluid is necessary to determine if it is acidic or basic. pH is evaluated using the pH meter. The performance of the fluids is affected by pH. Some fluids performed best at certain pH while the same fluids may be adversely affected by pH changes [5]. It is thus pertinent to determine the pH of the fluid to make sure that the pH. For gravel pack carrier fluids, HEC performs optimally in acidic pH mediums while Xantham is not affected by pH. It is, however, to note that operating in acidic pH mediums is detrimental to the integrity of the well's tubular such as the casing, the pipes, the tubing, etc., and as such is avoided by operators. Proper fluid design is critically imperative to determining the effects of pH on the fluid and how the pH medium affects the overall operational integrity of the well. It is however possible to achieve pH alteration to desired pH ranges using pH adjusters which are broadly employed in gravel pack carrier fluid designs to meet required well conditions and optimal performance [5].

2.5.2. Rheology

The most important rheological parameters tested on carrier fluids are the apparent viscosity and gel strength. The viscosity of the gavel pack carrier fluid is perhaps the most important property of the fluid. The viscosity determines how well the fluid would suspend the gravel to the target depth before being released [5].

It is important to design the proper viscosity for the fluid. This is because too high or too low viscosity are both detrimental to the gravel pack placement process [6]. Very high viscosity poses the risk of well damage while too low viscosity translates to the intermittent release of the gravel before reaching the target depth thus creating additional problems relating to increased frictional resistance and skin. Fann 35 viscometer is utilized in the determination of the apparent viscosity of the carrier fluid

2.5.3. Solids settling test

It is necessary to test the capacity of the carrier fluid to suspend solids. The solids settling test evaluates the ability of the carrier fluid to hold the solids in place until the target depth is reached. An efficient carrier fluid design will not release the suspended gravel until it reaches the target depth. In this test, the standard 10 ppg gel/slurry sand is used [5].

2.5.4. Gel Break

The gravel pack carrier fluid upon reaching the target depth is expected to release the suspended solids (gravel). This is a fundamental property of the carrier fluid that must be achieved in the fluid design. The gel break test evaluates the capacity of the carrier fluids to release the solids when needed at the target depth in the reservoir [6]. Breaker fluids are used to achieve the release of suspended gravel. However, the proper design and concentration of the gel breaker fluid must be calculated using static or dynamic methods. The gel is said to be broken when a viscosity of 10cp or less has been obtained for a dial readingof Fann 35 or Fann 50 which is used for temperatures above 93.3^{o}C.

2.6. Equations for Determination of Rheological Parameters

From the viscometer results, rheological parameters can be calculated using some SPE models. However, the equations to use are based on the type of rheological model. The basic rheological models include the Bingham plastic model, the power law model, and the Herschel-Bulkley model

2.6.1. Bingham plastic model and parameters

The Bingham plastic model is a two-parameter model that is described by the linear equation given in Equation 1.

$$\tau = \tau_y + \mu_p \gamma \quad (1)$$

where

τ= shear stress in lb/100ft^2

τ_y= yield point (PV) in lb/100ft^2

μ_p= Plastic viscosity (PV), cp

γ= shear rate, sec^{-1}

The two parameters described by the Bingham plastic model are the plastic viscosity and the yield point. Bingham plastic mode does not describe accurately the flow behaviour of low-shear-rate regions.

For the Bingham plastic model, the formula to calculate the plastic viscosity is given as

$$\mu_p = \frac{300}{N_2 - N_1}\left(\theta_{N_2} - \theta_{N_1}\right) \quad (2)$$

where

θ_{N_1}= viscometer reading at rotary speed N_1

θ_{N_2}= viscometer reading at rotary speed N_2

The Bingham plastic yield point is calculated using the formula

$$\tau_y = \theta_{N_1} - \mu_p \frac{N_1}{300} \quad (3)$$

2.6.2. Power Law Model

The power law is a non-linear two-parameter model described by Equation 4

$$\tau = K\gamma^n \quad (4)$$

where

K = power law consistency factor, cp or Pa.s

n = power law flow behaviour index, dimensionless

The two parameters described by the power-law model include the power law consistency factor and the power law flow behaviour index.

The power law consistency factor and flow behaviour index can be calculated using the API-recommended formula

$$n_p = \frac{Log\left(\frac{\theta_{N_2}}{\theta_{N_1}}\right)}{Log\left(\frac{N_2}{N_1}\right)} \quad (5)$$

$$K_p = \frac{\theta_N}{(1.703N)^{n_p}} \quad (6)$$

2.6.3, Herschel-Bulkley Model

The Herschel-Bulkley model is a three-parameter model that is described by Equation 7

$$\tau = \tau_y + K\gamma^n \quad (7)$$

where

K = Herschel-Bulkley consistency factor, cp or Pa.s

N = Herschel-Bulkley (HB) flow behaviour index, dimensionless

τ_y= yield stress lb/100ft^2 or Pa

For the Herschel-Bulkley model, the yield stress is calculated at low shear rates according to Equation 8

$$\tau_y = 2\theta_3 - \theta_6 \quad (8)$$

The flow behaviour index and consistency factor for the HB model can be estimated using equations 9 and equation 10 respectively

$$n_{HB} = \frac{Log\left(\frac{\theta_{N_2} - \tau_y}{\theta_{N_1} - \tau_y}\right)}{Log\left(\frac{N_2}{N_1}\right)} \quad (9)$$

The Herschel-Bulkley consistency index is calculated using Equation 10

$$K_{HB} = \frac{\theta_N - \tau_y}{(1.703N)^{n_{HB}}} \quad (10)$$

However, it must be noted that the correct model that would fit the experimental data and the accurate estimation of the rheological model parameters can only be determined by a curve using non-linear regression or machine learning such as genetic algorithm

3. MATERIALS AND METHODS

This section describes the materials and methods used in this study.

3.1. Materials

The materials used in the experiment include sodium persulfate (SP) used as gel breaker, Fe-2 used as an iron control agent, KCL brine which is the mixed fluid, K-35 used as pH buffer, BE-6, and BE-35 used as biocides, HEC used as a gelling agent, and distilled water. The concentrations and the functions of the materials used are given in Table 1.

Table 1. Description of materials used

Tabela 1. Opis upotrebljenih materijala

Materials	Concentration/1000gal	Function
KCl brine	2% bwow	Base fluid
BE-3S	0.15 lbs	Used as biocide
BE-6	0.15 lbs	Used as biocide
Fe-2	10 lbs	Used as iron control
HEC	40 lbs, 60 lbs	Functions as the Gelling Fluid
K-34	(pH 7-8)	Utilized as the pH Buffer
SP	10 – 25 gals	Used as gel breaker
Distilled Water	1000 gal	Used for mixing

The gravel pack carrier fluid was prepared by using the materials listed in Table 1. 40lbs/1000gal (40ppt) and 60lbs/1000gal (60ppt) HEC respectively were prepared using 2% bwow KCl as base fluid and varying concentrations of sodium persulfate (SP) breaker fluid. The HEC carrier fluid was mixed using a blender and additives were appropriately added according to the concentrations specified in Table 1. Each HEC concentration carrier fluid formulation was achieved by slowly adding HEC polymer, and then pH buffer to raise the pH to around 8 to 9 after the HEC was dissolved in the base fluid. The resulting mixture was then allowed for 30 minutes to achieve full gel hydration and then the pH, temperature, rheology, viscosity, and sand settling data were taken and recorded

3.2. Methods

The methods consist of experimental procedures and tests for the HEC carrier fluid formulation design. 40 ppt and 60 ppt gel loading of HEC were considered and investigated relative to the tests performed. The following tests were conducted: the pH test, the rheology test, the solids settling test, and the gel breaker test.

3.2.1. pH Test

For the pH test, first, 1000 ml of water was measured out and then 20 gals of KCl was measured and added to 1000 ml of water. the mixture of water and KCl was then stirred thoroughly. Then a pH meter was brought and inserted into the mixture to check its pH. Then, 0.15 pptg of BE-6 and 0.15pptg (of BE-35 biocides) were measured and added to the brine solution and stirred, then 10pptg of Fe-2 (iron control agent) was added to the resulting mixture. The resulting overall mixture was then thoroughly stirred and the pH was then taken with the pH meter and the result was recorded. Next, 40ppt of HEC was measured separately and added to the mixture, and then stirred until a viscous solution was achieved. Then sodium hydroxide was then added to the mixture to raise the pH of the mixture to near neutral value. Then the pH of the viscosified solution was then taken as the final gel pH of the mixture. The process was repeated for 60ppt of HEC gelling agents

3.2.2. Rheology Test

The hydrated gel was allowed to stand for 1 hour complete dissolution of the fish eye. The gel is then put into a VG viscometer and stirred at various revolutions per minute (RPM). The viscometer readings at the different RPMS were noted and recorded. This was repeated for various tempe-ratures indicative of reservoir conditions achieved by putting the gel in a bath and increasing its temperature by heating

3.2.3. Gel Breaker Test

The gel breaker test was conducted using SP gel breaker fluid. 200 ml of hydrated gel was measured out and then 1 ml of SP gel breaker fluid was measured and added to the hydrated gel. The resulting mixture was then put in a water bath and watched for some time until the gel broke. The gel breaking time was then realized and recorded and the viscosity of the fluid at the time of gel break was also recorded. This was conducted for various RPMs

3.2.4. Sand Settling Test

For the investigation of the sand settling test, proppant sand was used as the gravel. First 150ml of the hydrated gel was measured, then 180g of proppant sand (20-40 carbolyte) was measured out. The gel was then poured into the proppant and timed. When the sand settles in the clear liquid with time, the height of the clear liquid was recorded against the time. The test was conducted for 40ppt and 60ppt of HEC gelling fluids while keeping other materials the same

4. RESULTS AND DISCUSSION

The results for HEC fluid are given and discussed in this section. The result comprises the fluid rheology, the sand settling test, the gel break results

4.1. The rheological properties of HEC fluid

For the rheological properties of the HEC gravel pack carrier fluid formulated, rheological parameters determined include the shear stress, plastic viscosity, the flow behaviour index, and the consistency index

The shear stress shear rate relationship for the 40ppt carrier fluid at different bottomhole temperatures is given in Figure 2.

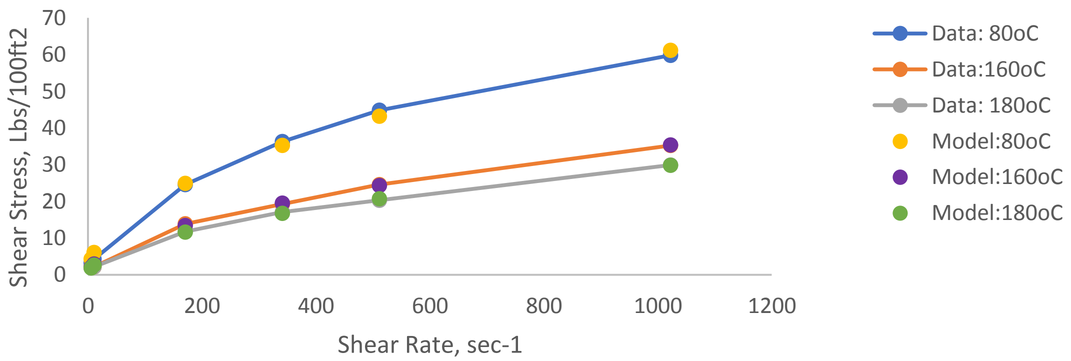

Figure 2. Shear stress vs shear rates for 40ppt HEC carrier fluid formulation

Slika 2. Napon smicanja u odnosu na brzinu smicanja za formulaciju noseće tečnosti HEC od 40ppt

For 40ppt HEC, the shear stress decreases as bottomhole temperatures are increased. The shear stress at 80°C is much higher than that for 160°C and 180°C bottomhole temperatures. However, the shearing properties of the fluid are adequate to maintain the required gravel transport. Non-linear regression was used to fit the data to determine the rheological model of the 40ppt HEC fluids at different test temperatures. From the non-linear regression curve fit, it was observed that the 40 ppt HEC carrier fluid tested at 80°C, 160°C, and 180°C was best fitted by the power law model.

The R^2 values for the power law regression fit the experimental data for the 40ppt HEC carrier fluids are 0.9967, 0.9989, and 0.9989 for 80°C, 160 °C, and 180 °C temperatures respectively. The curve fit analyses reveal low-shear stress at low shear rates for the HEC fluids formulations.

The shear stress shear rate relationship for 60ppt HEC carrier fluid for the downhole temperatures considered is given in Figure 3.

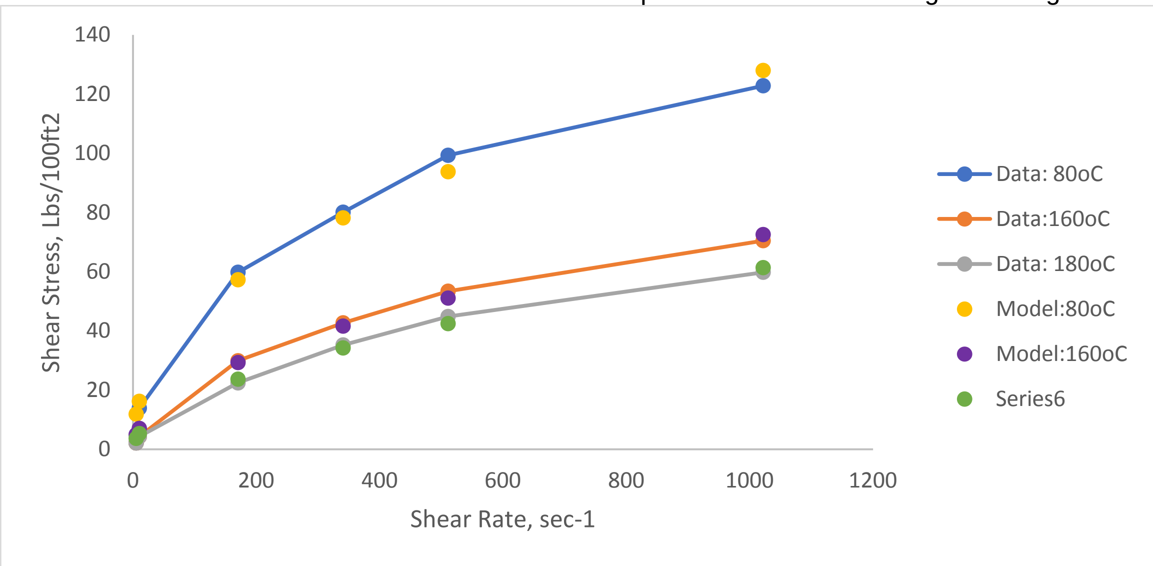

Figure 3. Shear stress vs shear rate plot for 60ppt HEC carrier fluid formulation

Slika 3. Grafikon napona smicanja u odnosu na brzinu smicanja za formulaciju noseće tečnosti HEC od 60ppt

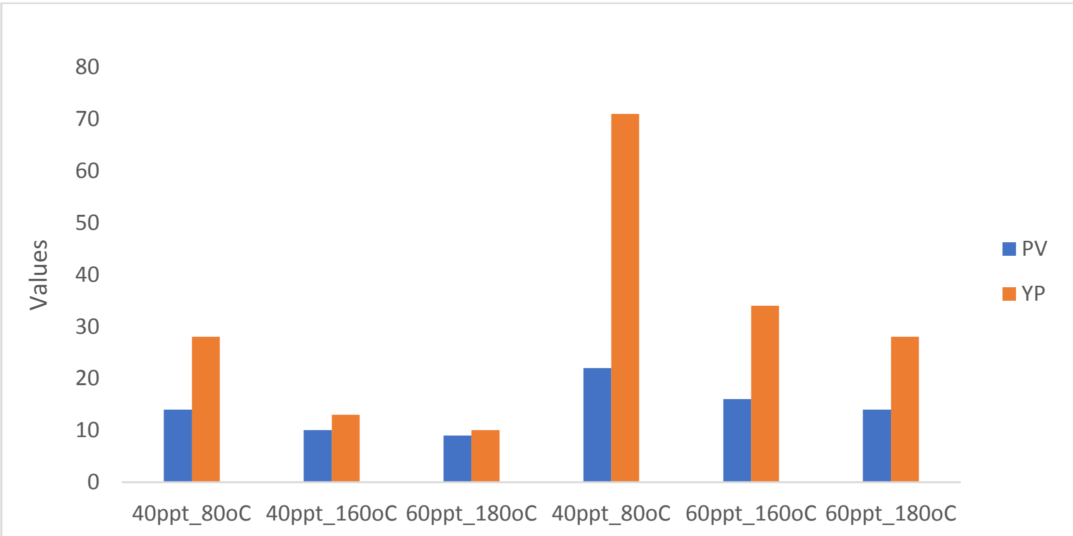

Figure 4. Plastic viscosity and yield point for the 40 ppt and 60ppt HEC carrier fluid

Slika 4. Plastični viskozitet i granica tečenja za HEC noseću tečnost od 40 ppt i 60ppt

Figure 3 shows the shear stress vs shear rate relationship for the 60ppt HEC carrier fluid formulation. The solid line plots show the original data while the round dots show the non-linear fit to the experimental data. It can be seen that the shear stress increases with shear rates. This reveals that the fluid has shear-thinning characteristics. More so, the power law model gave the best fit to the experimental data for the non-linear regression analyses conducted with high R^2 values. The R^2 values for the power law regression fit the experimental data for the 60ppt HEC carrier fluids are 0.9939, 0.9973, and 0.9976 for 80°C, 160 °C, and 180 °C temperatures respectively. The curve fit analyses reveal low-shear stress at low shear rates for the HEC fluids formulations

The plastic viscosity and yield point for the 40ppt and 60ppt HEC carrier fluid formulations are shown in Figure 4.

As can be observed from Figure 4, the plastic viscosity and yield point decreased with an increase in bottomhole temperature for both 40ppt and 60ppt HEC gels. Moreover, the plastic viscosity and yield point increase with an increase in gel loading, the 60ppt HEC carrier formulation has higher plastic viscosity and yield point than the 40ppt HEC carrier fluid formulation. The fluid exhibits shear-thinning characteristics because. Fluid with high plastic viscosity is required for optimum sand suspension at low shear rates.

The power-law consistency (k) factor and flow behaviour index (n) as determined from the curve fit for the 40ppt and 60ppt HEC carrier fluid formulations are given in described in Table 2.

Table 2. k and n values for 40ppt and 60ppt HEC carrier fluid

Tabela 2. Vrednosti k i n za 40ppt i 60ppt HEC noseće tečnosti

Gel Loading	Temperature, °C	n	k, Lb-sec/100ft^2
40ppt	80	0.501603	3.56618
	160	0.541212	0.711127
	180	0.526367	0.619569
60ppt	80	0.448689	48.60293
	160	0.505952	4.653233
	180	0.531279	2.268237

The consistency factor (k) and the flow behaviour index (n) for HEC carrier fluids are given in Table 2. The n and k values for 40ppt HEC carrier fluid at 80 °C are 0.5016 and 3.566 Lb-sec/100ft^2 respectively, while for 160 °C, the n and k values are 0.5412 and 0.7112 Lb-sec/100ft^2 respectively. Meanwhile, the n and k values for 180 °C are 0.5263 and 0.6195 Lb-sec/100ft^2 respectively. The consistency factor of 40ppt HEC carrier fluid decreases with increasing temperature. The consistency factor, k relates to the pumpability of the fluid and its viscosity. Thus, 40ppt HEC fluid requires more pump power to transport it to the desired depth. Moreover, the flow behaviour index, n indicates the degree of non-Newtonian characteristics of the fluid. It is seen that for all bottomhole temperatures considered the flow behaviour index was observed to be within the range of 0.5±0.04. Similarly, the n and k values for 60ppt HEC carrier fluids are 0.4487 and 48.6029 lb/100ft^2 respectively for 80°C, 0.5056 and 4.6532 lb/100ft^2 respectively for 160°C and 0.5312 and 2.6282 lb/100ft^2 respectively for 180°C.

It can be generally observed that the consistency index increases with an increase in gel loading, HEC carrier fluid of 40ppt has more consistency index than 60ppt HEC formulation. This is expected as an increase in gel results in to increase in the viscosity of the mixture which increases the consistency factor. Thus, higher pump pressure is required to transport higher HEC gel carrier fluids. Nonetheless, the flow behaviour index did not vary appreciably due to variations in gel loadings or temperature.

The general results for plastic viscosity, yield point, n, k and R2 regression fit to the power law model is given in Table A1 in the appendix carrier fluid formulation is given in Table A2 in the appendix.

Table A1: Rheological properties of HEC fluid

Tabela A1: Reološka svojstva HEC tečnosti

Gel Concentration	Temperature, °C	600 rpm	300 rpm	200 rpm	100 rpm	6 rpm	3 rpm	PV, cP	YP, Lb/100ft2	n	k, Lb-sec/100ft2
40 ppt HEC	80	56	42	34	23	4	3	14	28	0.501603	3.56618
	160	33	23	18	13	2	2	10	13	0.541212	0.711127
	180	28	19	16	11	2	2	9	10	0.526367	0.619569
60 ppt HEC	80	115	93	75	56	13	2	22	71	0.448689	48.60293
	160	66	50	40	28	4	2	16	34	0.505952	4.653233
	180	56	42	33	21	4	2	14	28	0.531279	2.268237

4.2. Sand Settling Test

Sand settling relates to the capacity of the HEC polymer to suspend the gravel (proppant) in the wellbore at wellbore conditions. The general results for sand settling test for the 40ppt and 60ppt HEC

Figure 5 shows the sand settling capacity of 40ppt and 60ppt HEC carrier fluid formulations at bottomhole temperatures of 80 °C, 160 °C, and 180°C.

Table A2. Sand settling test

Tabela A2. Test taloženja peska

Time, minutes	Height of clear liquid, cm					
	40 ppt HEC			60 ppt HEC		
	80°C	160°C	180°C	80°C	160oC	180°C
0	0	0	0	0	0	0
1	10	0	24	3	5	6
2	15	23	25	5	10	12
3	20	25	26	6	15	18
4	25	26	26	8	19	22
5	26	26	27	12	22	23
10	27	27	27	15	22	23
20	27	27	27	19	22	23
25	27	27	27	23	22	23

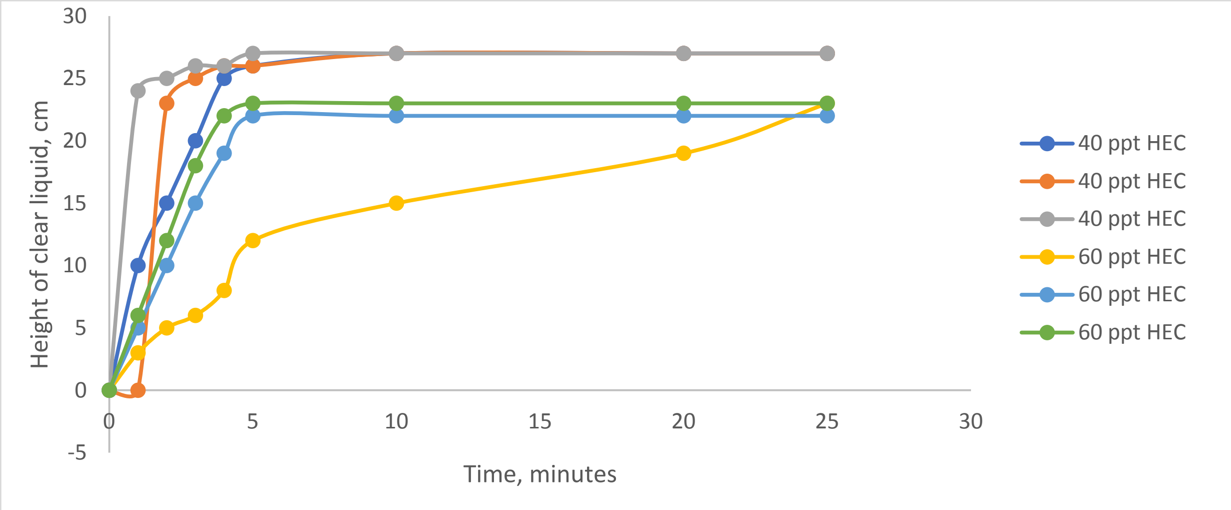

Figure 5. Sand settling for the polymer concentrations at different temperatures

Slika 5. Taloženje peska za koncentracije polimera na različitim temperaturama

It can be observed from Figure 5 that the sand settling capacity of HEC polymer is a function of temperature and polymer concentration. The sand settling capacity of the 40ppt HEC is more than that of 60ppt HEC no matter the bottomhole temperature. For each gel loading for 40ppt and 60ppt gel HEC fluids, the gravel settling time increases as bottomhole temperature is reached until a maximum point is reached for which the settling time remains constant even with increased temperatures. Moreover, 40ppt gel shows higher sand settling than 60ppt gel. This is because, at higher viscosity, the less the sand can settle in the fluid.

Furthermore, it is observed that sand settling for 40ppt HEC began almost immediately even at surface temperature, and then increases with increasing temperature. At lower sand settling times, a significant increase in the settled sand was observed as temperature increases for both the 40ppt and 60ppt HEC carrier fluid formulations. However, at higher time intervals, the sand settling almost became constant no matter the temperature for each gel loading. Increasing polymer concentration gel loading from 40ppt to 60ppt greatly improves the gravel suspension capacity of HEC fluid both at low and higher temperatures.

4.3. Gel Break

Gel break analyses were achieved using SP breaker fluid by exploring different concentrations. The results of the gel break for the 40ppt and 60ppt HEC fluids formulation are shown in Figure 5. The gel break test was carried out at 300 RPM. In the field, a gel is regarded as broken if its viscosity downhole is close to the viscosity of water at wellbore temperatures. Normally 10cP is taken as the minimum or base viscosity in analyzing gel break and is used in this study. Thus, a gel is considered to be when its viscosity after some time when a breaker fluid has been added is equal to or less than 10cP. The general results for gel break test for the 40ppt HEC carrier fluid formulation is given in Table A3 in the appendix. Figure 6 shows the gel break result for 40ppt HEC.

Table A3. Gel break result for 40ppt HEC

Tabela A3. Rezultat razbijanja gela za 40ppt HEC

Temp	Time, min	20lbs	10lbs	5lbs	1 lbs
160	0	43	43	43	43
	10	20	22	23	26
	20	10	15	17	20
	30	9	10	13	15
	60	0	7	10	14
180	0	43	43	43	43
	10	10	18	21	24
	20	7	8	10	18
	30	6	6	7	13
	60	0	0	0	10

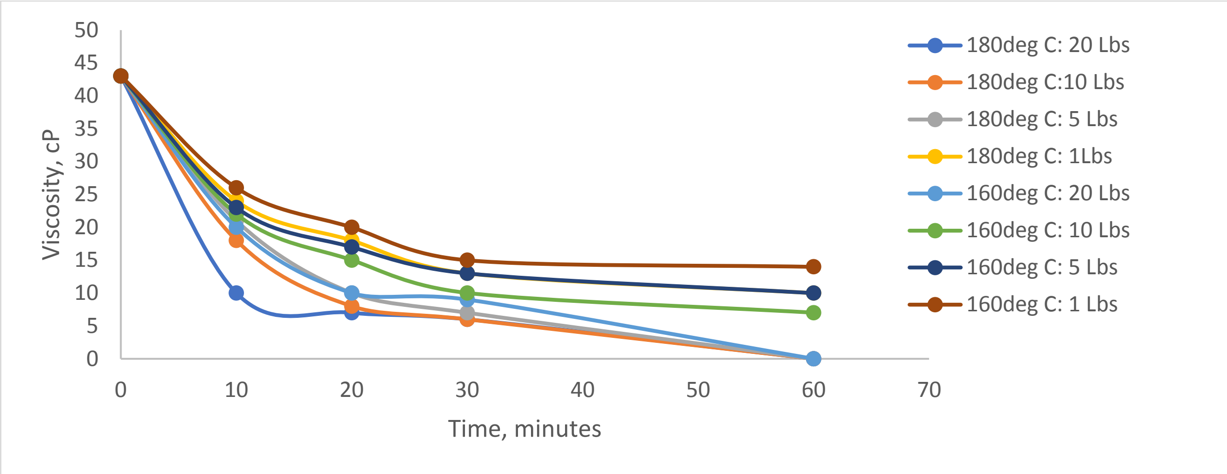

Figure 6. 40ppt HEC fluid gel break at different breaker fluid concentrations and temperatures

Slika 6. 40ppt HEC tečni gel razbijanje pri različitim koncentracijama i temperaturama tečnosti za razbijanje

Figure 6 shows the gel break for different concentrations of breaker fluid for the 40ppt HEC fluid. It is seen that temperature and breaker fluid concentration affects the HEC fluid gel break. The time of gel break was observed to decrease with an increase in temperature. This is expected because, at high temperature, the viscosity and gel properties of the fluid decreases. Furthermore, the gel break time decreases with an increase in breaker fluid concentrations. Moreover, the effect of temperature on break time is more pronounced at higher breaker concentrations than at lower concentrations. The general results for gel break test for the 60ppt HEC carrier fluid formulation is given in Table A4 in the appendix

As can be observed from Figure 7, the break time for 60ppt HEC decreases with increasing concentration of SP breaker from 1ppt to 20ppt at the same temperature. Furthermore, it was observed that the break time decreases when the temperature was increased from 160°F to 180°F. The effect of temperature on break time was more pronounced at higher breaker concentrations than at lower concentrations. Generally, the 40ppt gel broke at an earlier time than the 60 ppt gel.

Table A4. Gel break result for 60ppt HEC

Tabela A4. Rezultat razbijanja gela za 60ppt HEC

Temp	Time, min	20lbs	10lbs	5lbs	1 lbs
160	0	98	98	98	98
	10	68	70	71	71
	20	28	44	58	65
	30	16	28	44	55
	60	9	15	34	51
180	0	98	98	98	98
	10	23	24	29	62
	20	8	10	18	46
	30	6	7	9	37
	60	4	4	6	25

The gel break result for 60ppt HEC is given in Figure 7.

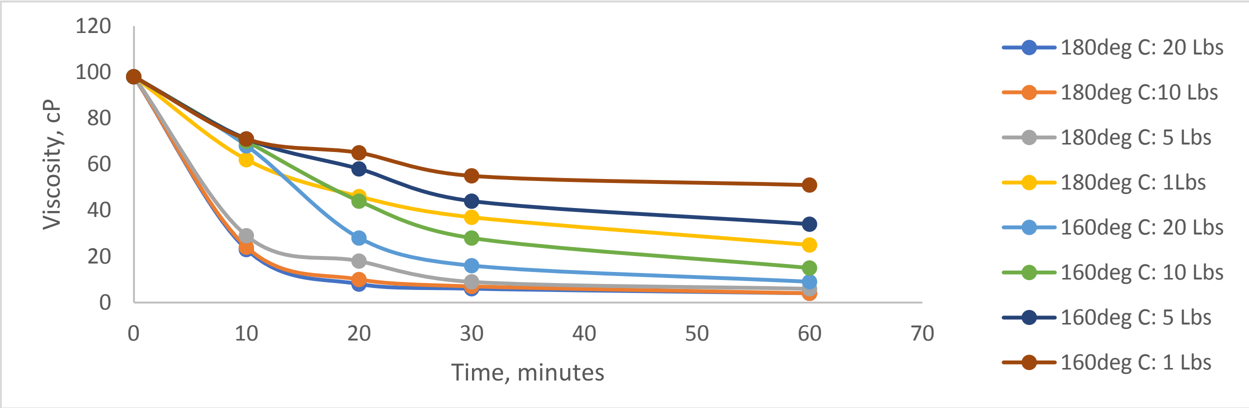

Figure 7. 60ppt HEC fluid gel break at different polymer concentrations and temperatures

Slika 7. 60ppt HEC tečni gel razbijanje pri različitim koncentracijama i temperaturama polimera

5. CONCLUSION

Gravel pack carrier fluid requires adequate design and analyses because of downhole operational conditions. Effective gravel (proppant) transport hinges on the choice and design of the carrier fluid. The use of HEC as a polymer in gravel pack carrier fluid formulation was investigated in this study. Several factors such as wellbore temperature, HEC polymer concentration, and gel breaker concentrations were evaluated to determine the performance of HEC in gravel pack carrier fluid formulation for the transport and placement of gravels during sand control operations.

HEC fluid showed good gravel settling which began immediately in contact with the gravel. Sand/gravel suspension was improved greatly with the increased addition of breaker fluids both for 40ppt HEC and 60ppt HEC fluids. Furthermore, temperature affected the gel break time by causing the HEC carrier fluid to break faster. Quicker gel break was achieved by adding higher concentrations of gel breaker fluids.

The break time of HEC polymer increases with an increase in polymer concentration. The effect of temperature on the rate of HEC polymer degradation was more pronounced at higher gel breaker concentrations. The consistency index and flow behaviour index are very important parameters used in predicting the flow behaviour of fluids in the tubing.

The condition of the well is imperative in the design and formulation of carrier fluid for gravel pack placement and used for sand control. Adequate well data will translate to optimal design to enhance the performance of the carrier fluids as relevant information regarding the well will help the production engineer to design efficient carrier fluid. HEC exhibited good rheological properties, sand settling, and break capability and should be used both for low-temperature and high temperature wells.

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IZVOD

ANALIZA PERFORMANSI POLIMERA HIDROKSIETIL CELULOZE (HEC) KAO SREDSTVA ZA ŽELIRANJE U TEČNOJ FORMULACIJI NOSAČA ŠLJUNKA ZA KONTROLU PESKA U BUNARIMA ZA PROIZVODNJU UGLJOVODONIKA

Ova studija razmatra performanse polimera 40ppt i 60ppt hidroksietil celuloze (HEC) koji se koristi kao sredstvo za želiranje u formulaciji nosećih tečnosti za transport šljunčanog omotača u operacijama kontrole peska u naftnim i gasnim bušotinama. Tečnost za nosač šljunka je pripremljena dodavanjem adekvatnih količina natrijum persulfata (SP) koji se koristi kao razbijanje gela, Fe-2 koji se koristi kilo sredstvo za kontrolu gvožđa, KCL slani rastvor kao mešana tečnost, K-35 koji se koristi kao pH pufer, BE-6, i BE-35 koji se koristi kao biocid, HEC koji se koristi kao sredstvo za želiranje i destilovana voda. Razmatrani su efekti temperature, opterećenja gela i koncentracije tečnosti za razbijanje na reologiju, vreme lomljenja gela i taloženje peska formulisanog HEC nosećeg fluida. Rezultati su pokazali da se napon smicanja, plastični viskozitet i tačka tečenja i faktor konzistencije smanjuju sa povećanjem temperature na dnu rupe i za 40ppt i za 60ppt HEC gelove. Štaviše, uočeno je da je indeks ponašanja protoka u opsegu od 0,45±0,1 40ppt i 0,5±0,04 za 60ppt HEC opterećenja gela, respektivno i pokazuje karakteristike smicanja-razređivanja. Dobro taloženje šljunka je primećeno za HEC gelove kada su u kontaktu sa šljunkom, dodavanje tečnosti za razbijanje uveliko je poboljšalo suspenziju peska/šljunka za 40ppt i 60ppt gel opterećenja. Vreme loma gela HEC gela se povećava sa povećanjem punjenja gela, a pri višim koncentracijama tečnosti za razbijanje, razgradnja HEC gela postaje kritičnija kako temperatura raste. Rezultati ističu adekvatne performanse HEC polimera kao tečnosti za šljunak u kontroli peska.

Ključne reči: *Noseća tečnost, HEC, kontrola peska, tečnost za razbijanje, šljunak*

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