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ORIGINAL PAPER - PRODUCTION ENGINEERING

Evaluation of using HEDTA chelating agent to clean up long horizontal heterogeneous sandstone wells without divergent

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Abstract The removal of the calcium carbonate water-based filter cake and the associated formation damage after drilling is a very difficult task, especially in horizontal and extended reach wells. The horizontal section length could be 20,000 ft or more with different permeability distributions, which makes the damage caused by the drilling fluid vary from one section to another. The filter cake removal in heterogeneous long horizontal lateral needs diverters to distribute the cleanup fluid through the entire section. In this paper, a smart fluid (HEDTA of 20 wt% and pH 4, hydroxyethyl ethylenediamine triacetic acid trisodium salt) was evaluated to remove the damage caused by calcium carbonate weighted drilling fluid for the horizontal and extended reach wells without adding gelling agents. This fluid will react with the calcium carbonate in the filter cake and the calcium carbonate in the formation to produce high viscosity fluid that will divert the fresh flow through the less permeable sections in the horizontal well. Parallel coreflooding experiments were used to confirm the diversion ability of this chemical through two sandstone cores with different permeability. The results obtained showed that the viscosity of the stimulation fluid increased at least 3 times after the treatment of the sandstone cores and the parallel coreflooding showed good ability of diversion for the fluid. The experimental results were used to describe the process of diversion using this fluid mathematically. HEDTA chelating agent showed good ability to remove the damage caused by drilling fluid from different sandstone cores with different permeabilities.

Keywords Water-based drilling fluid · Filter cake · Sandstone reservoir · Horizontal wells · Formation damage · Divergent · Stimulation

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Introduction

Well productivity can be maximized by drilling horizontal, multilaterals, and extended reach wells (Yildiz 2005). In overbalanced drilling operations, the drilling fluid tends to filtrate into the formation with fine particles, which are smaller than the pore size of the formation and cause major formation damage around the wellbore in addition to the filter cake damage. Robert and Richard (1998) stated that the main sources of the formation damage are the drilling, completion, and workover operations.

The drilling fluid should be designed to form impermeable filter cake on the formation face to minimize the formation damage. Sag tendency of the weighting material (Nguyen et al. 2011) should be avoided by using the proper additives. The rheological properties of the drilling fluids play key factor in the drilling operations. It is recommended to add additives such as blast furnace slag (BFS) to reduce the spurt loss and form a good filter cake (Nandurdikar et al. 2002). Formation damage can be repaired and prevented by adding microemulsion additives to the drilling fluids (Abdo and Haneef 2012). Nanoparticles addition to the drilling fluid enhanced the rheological properties of the drilling fluid (Penny et al. 2005). Nanomaterials are those materials that have an average particle size of 1–100 nm with a very high surface to volume ratio (Amanullah and Al-Tahini 2009). Because of the huge surface area of the nanoparticles, it can be used as a fluid loss control, shale inhibitor, and for rheology control when added to the drill-in fluid with a small concentration (Amanullah and Al-Abdullatif 2010). The main idea is that the nanoparticles will provide good sealing at the early stage of filtration and will form thin and impermeable filter cake, which will prevent more filtration to the formation and reduce the formation damage.

Damage removal in carbonate reservoirs

In carbonate reservoirs, calcium carbonate-based filter cake cleanup fluids include acids, oxidizers, enzymes, or combinations of these chemicals. Rapid reaction of HCl with calcium carbonate at reservoir conditions will cause excessive consumption of calcium carbonate at the heel and this will lead to non-uniform distribution of the acid through the horizontal section (Buijse et al. 2004). Due to leak off, large volume of HCl is usually lost into the formation (Ryan et al. 1995; Burnett 1998; Parlar et al. 1998).

Oxidizers were not effective in removing the polymer residue, especially in horizontal intervals (TjonJoe-Pin et al. 1993). Oxidizers required an activator to start working at low temperature. In addition, oxidizers may be consumed in many different competing reactions occurring downhole, reducing their availability to break the polymer (Norman et al. 1989).

Enzymes have some limitations; for example, they will only attack specific polymer chains, and the calcium carbonate components will not be removed (Battistel et al. 2005). Enzyme did not completely remove the filter cake polymer (Hembling et al. 2000). Specific enzymes were effective in removing most of drill-in fluid filter cake, and they were able to break xanthan gum and starch that are used in the drill-in fluids (Al-Otaibi et al. 2004).

Damage removal in sandstone reservoirs

The filter cake properties and the internal invasion were heterogeneous along the horizontal section of sandstone formations (Bageri et al. 2013). It was found that the percentage of sand particles varies within the horizontal latera of the well. The sand content increased from the heel to the toe of the horizontal section. The heterogeneity of the horizontal section permeability will form heterogeneous filter cake along the same section (Bageri et al. 2013). Filter cake heterogeneity plays a key role in designing the chemical treatment process to remove the filter cake (Elkatatny et al. 2012, 2013).

The use of HCl in sandstone formations was proved to be more damaging than removing the damage even after introducing different polymers gelling materials to enhance HCl diversion by increasing the viscosity of the acid. It was found that the illitic-sandstone reservoirs are very sensitive to HCl-based fluids and when HCl contacts illitic-sandstone, it breaks down and increases the risk of formation damage due to fines migration (Mahmoud et al. 2015). The migration of fines through the porous media blocks the pores, reduces permeability, and decreases the production rate of oil and gas wells. 15 wt% HCl caused severe damage to sandstone cores with different illite contents of 1, 10, 14, and 18 wt% of the sandstone cores that were used in the coreflood experiments at 300 °F (Mahmoud et al. 2015).

The process of diversion of the stimulation fluid in carbonate wells by using either viscoelastic surfactant (VES) or polymers-based hydrochloric acids cannot be used in sandstone formations (Al-Mutawa et al. 2005; Nasr-El-Din and Samuel 2007). In sandstone reservoirs, there is no enough calcite to react with these fluids to produce the gel diverting materials and because of the adsorption of polymers and surfactants by the sandstone formations which will create more damage (Friedmann 1986).

Elkatatny (2016) stated that chelating agents were heavily used in oil industry as iron control agents, scale removers, and recently introduced as stand-alone stimulation fluids in sandstone and carbonate reservoirs. Mahmoud et al. (2011a, 2014) performed several coreflooding experiments using different types of sandstone and limestone cores at high temperatures using chelating agents such as EDTA, GLDA, and HEDTA at different pH values and different concentrations. HEDTA and EDTA chelating agents are compatible with sandstone cores containing high percent of clay minerals such as illite and kaolinite. Chelating agents did not cause fines migration or clay swelling when injected through different types of sandstone cores (Mahmoud et al. 2011b). Ali et al. (2005) concluded that HEDTA solutions (low pH) can stimulate sandstone and carbonate formations at high temperature.

Sokhanvarian et al. (2013) evaluated the thermal stability of chelating agents. They concluded that chelating agents start to decompose at temperatures greater than 350 °F and the thermal stability of chelating agents can be enhanced by increasing the pH. Al-Ibrahim et al. (2015) concluded that no precipitation or emulsion was observed when mixing EDTA-based fluid with drill-in fluid (oil-based mud) and the removal efficiency of the formed filter cake was 93% after soaking for 90 h. They stated that chelating agents are not compatible with reservoir formation water and they will form severe precipitation of insoluble damaging by-products when mixed with formation water.

The objectives of this research are to: (1) introduce a diversion fluid to remove the formation damage from the maximum reservoir contact (MRC) and extended reach wells in sandstone reservoirs without adding gelling materials, (2) remove the damage caused by calcium carbonate weighted drilling fluid using the introduced diversion fluid, (3) assess the potential of formation damage by calculating the retained permeability ($K_{final}/K_{initial}$) of the core samples, and (4) use the experimental data to describe the process of diversion using the proposed fluid in horizontal well mathematically.

Experimental studies

Materials

Table 1 shows the composition of the water-based drilling fluid, in which calcium carbonate ($CaCO_3$) was used as a weighting material (70 μm), starch was used for fluid loss control, and xanthan gum was used for viscosity control.

To simulate the reservoir section, Berea sandstone cores with a permeability range of 78–110 md were used. These cores have mineralogical composition shown in Table 2. XRD was used to analyze the mineralogical composition of the core samples. All cores used in this study were cut from a Berea sandstone cube (9 in. × 9 in. × 9 in.). Samples from each core were taken as well as from the block itself, and all showed the same mineralogical composition as listed in Table 2. The core length was 6 inch and the diameter was 1.5 inch for all core samples. The cores have an average porosity of 19%. Chelating agent [20 wt% HEDTA (hydroxyethyl ethylenediamine triacetic acid trisodium salt), pH 4], was used as cleaning fluid to enhance the damaged permeability in the horizontal section of sandstone reservoirs.

Table 1 Drilling fluid composition on laboratory scale

Material	Quantity	Units
Distilled water	308	g
Defoamer	0.33	g
XC-polymer	1.20	g
Biocide	0.2	g
Starch	2.00	g
KCl	97.6	g
KOH	1.00	g
Sodium sulfide	0.25	g
$CaCO_3$ (70 μm)	7.99	g
Lubricant	6.58	g

Table 2 Mineralogy of sandstone cores

Mineral	Berea sandstone (wt%)
Quartz	86
Dolomite	01
Calcite	2
Feldspar	3
Kaolinite	5
Illite	1
Chlorite	2
Plagioclase	–

Drilling fluid properties

Table 3 shows that the water-based drilling fluid density is 120 lbm/ft^3 and the plastic viscosity is 35 cP, yield point is 25 lb/100 ft^2, and gel strength is 13 and 18 lb/100 ft^2 for 10 s and 10 min, respectively.

Viscosity change in the cleaning fluid

The main idea of using HEDTA as a divergent depends on the increase in the viscosity of the chelating solution when it reacts with calcium carbonate. As the viscosity of the fluid increases, the required pressure to flow the fluid into the permeable formation increases.

HEDTA chelating agent shows the ability to react with carbonate in the sandstone cores and produce high viscosity (at least 3 times more than the initial value of its initial viscosity) that will divert the flow through the less permeable core sample in the parallel core flooding. The viscosity of Newtonian fluids is strong function of their density. When HEDTA chelating agent reacts with the multi-valent cations from the filter cake and the formation, its density goes up and in turn the viscosity also will increase.

Capillary tube viscometer (Ubbelhold type) was used to measure the viscosity of 20 wt% the HEDTA solution at different calcium concentrations at 80 °F. Figure 1 shows that as the concentration of calcium increased from 0 to 30,000 ppm, the viscosity of the chelating agent solution increased from 1.8 to 5.64 cP.

Permeability of the horizontal section

A horizontal section (4500 ft) was drilled a long a sandstone reservoir that has a heterogeneity in the horizontal

Table 3 Drilling fluid properties

Property	Conditions	Value
Density, pcf	14.7 psi and 80 °F	120
Plastic viscosity, cP	14.7 psi and 120 °F	35
Yield point, lb/100 ft^2		25
Gel strength (10 s), lb/100 ft^2		13
Gel strength (10 min), lb/100 ft^2		18
pH	14.7 psi and 80 °F	10

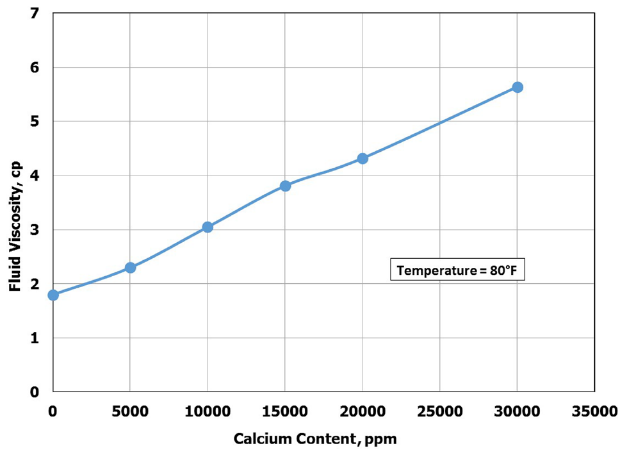

Fig. 1 Viscosity measurements of 20 wt% HEDTA solutions at different calcium concentrations

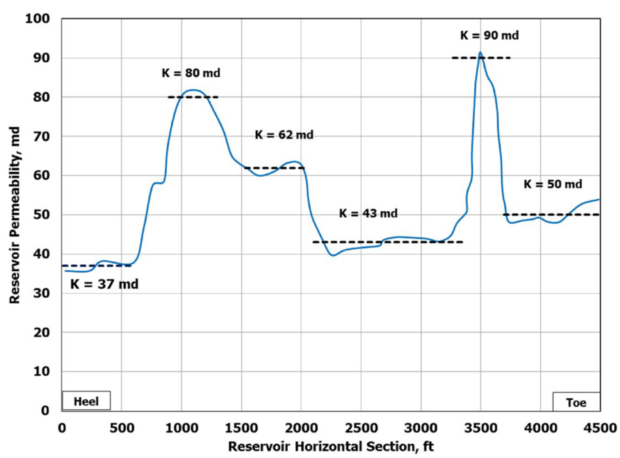

Fig. 2 Permeability distribution along the horizontal reservoir section

section as shown in Fig. 2. The permeability of the lateral was obtained from the production logging data after flowing the well during running the production logging tool. The horizontal section can be divided into six parts with an average permeabilities (37, 80, 62, 43, 90 and 50 md), respectively, form the heel to the toe. The alteration in permeability was due to the damage caused by drilling fluid during drilling this section.

Parallel core flooding

The parallel core flooding system shown in Fig. 3 was used to evaluate the performance of the Na_3HEDTA to divert the flow through the low-permeablity core sample and determine the change in permeability of the cores after flooding.

The experiments were performed at 100 °C reservoir temperature, and the following are the flooding sequence:

1. The drilling fluid was injected (1 cm^3/min) through the parallel core flood until the pressure reached the maximum limit of the transducer (1500 psi).
2. Flow back was conducted to determine the damaged permeability using 3 wt% KCl solution.
3. The cleaning fluid (Na_3HEDTA of 20 wt%) was injected through the damaged Berea sandstone cores with different permeability contrasts. The injection rate was 1 cm^3/min, and it was injected for three pore volumes.
4. Flow back was conducted to determine the final permeability using 3 wt% KCl solution.

Three sets of core samples were selected as shown in Table 4. In set #1, both cores have very close initial permeability (almost 85 md), the damaged permeability of both cores was almost 42 md, and permeability contrast of the damaged cores was equal to one ($K_{core\ \#2}/K_{core\ \#1} = 1$). In set #2, both cores have different initial permeability and the contrast of damaged permeability was 2 ($K_{core\ \#2}/K_{core\ \#1} = 2$), and set #3 has a contrast of 3 ($K_{core\ \#2}/K_{core\ \#1} = 3$) after damage. The cleaning fluid (Na_3-HEDTA 20 wt%) was used to stimulate the three sets of core sample that were selected.

The coreflooding setup used in this study consists of two back pressure regulators at the outlet of each core holder. A hydraulic pump was used to apply the required confining pressure on the core. High-accuracy pressure transducers were used to measure the pressure drop (accuracy = 0.02 psi) with the range of 0–300 psi. The coreflooding experiments were carried out at 100 °C. Before running the coreflooding experiments, the core was first saturated with brine and the pore volume was calculated. In each coreflooding experiment, the core was first loaded into the core holder at an overburden pressure 500 psi more than the inlet pressure was applied at 100 °C. The pressure was stabilized by injecting the brine solution, and then the injection of HEDTA started.

Results and discussion

Stimulation of Berea sandstone using Na_3HEDTA

The results obtained showed that the Na_3HEDTA (20 wt%) stimulated the sandstone core and there was a high degree of enhancement in the damaged permeability. The ratio of final permeability to the damaged permeability ($K_{final}/K_{damaged}$) was high for the lower permeability core of each sample of the three selected sets, as shown in Table 5. These results explained the divergence mechanism of the Na_3HEDTA as it started reaction with calcium carbonate particles in the high-permeability core first, and as a result

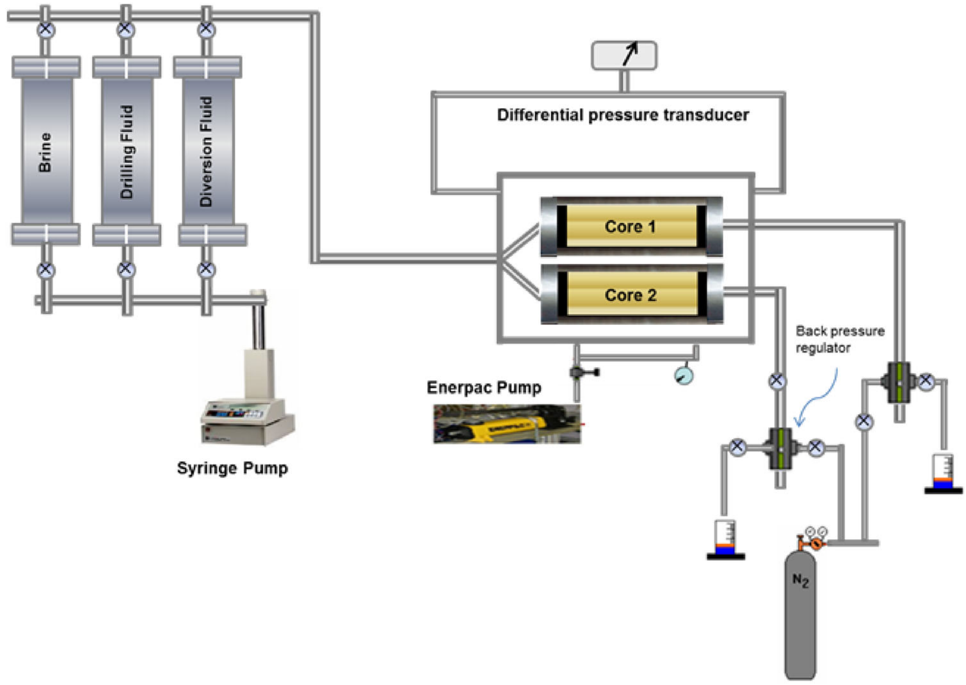

Fig. 3 Schematic diagram of parallel core flooding system

Table 4 Permeability distribution of the three-set experiments

	Initial permeability, md	Damaged permeability, md	Damaged permeability contrast ($K_{core\ \#2}/K_{core\ \#1}$)
Set #1			
Core 1	85	40	1
Core 2	87	42	
Set #2			
Core 1	95	36	2
Core 2	105	74	
Set #3			
Core 1	78	15	3
Core 2	110	50	

Table 5 Results of stimulation of Berea sandstone using Na_3HEDTA

	Final permeability, md	Enhancement factor ($K_{final}/K_{damaged}$)	Retained permeability ($K_{final}/K_{initial}$)*100
Set #1			
Core 1	80	2	94
Core 2	83	1.98	95
Set #2			
Core 1	73	2	77
Core 2	98	1.3	93
Set #3			
Core 1	69	4.6	88
Core 2	94	1.9	85

the viscosity of the chelating solution increased and the fluid was diverted to the lower permeability core. Table 5 shows the retained permeability of sandstone cores which was calculated using Eq. 1.

$$\text{Retained permeability} = \frac{K_{\text{final}}}{K_{\text{initial}}} \times 100 \quad (1)$$

Figure 4 shows the percentage of the recovered permeability of the sandstone cores used in this study within the range of 77–95%.

Diversion using Na_3HEDTA fluid

Na_3HEDTA reacts with carbonate in the sandstone cores and removes the damage, as confirmed in the results of the previous part. In addition to the calcium carbonate removal, HEDTA viscosity will build up due to the calcium chelation and this will promote the diversion features of HEDTA.

This concept introduced Na_3HEDTA as a diversion technique to remove the formation damage from maximum reservoir contact and extended reach wells in sandstone reservoirs. When HEDTA is injected into Berea sandstone cores with different permeability contrast in parallel coreflooding, the fluid enters the high-permeability core and reacts with carbonate in the sandstone core. Then, the viscosity of the fluid increased and caused the pressure drop to increase; therefore, the viscous fluid (Na_3HEDTA) will divert the fresh injected HEDTA (low viscosity fluid) to the less permeable core sample in the parallel coreflooding.

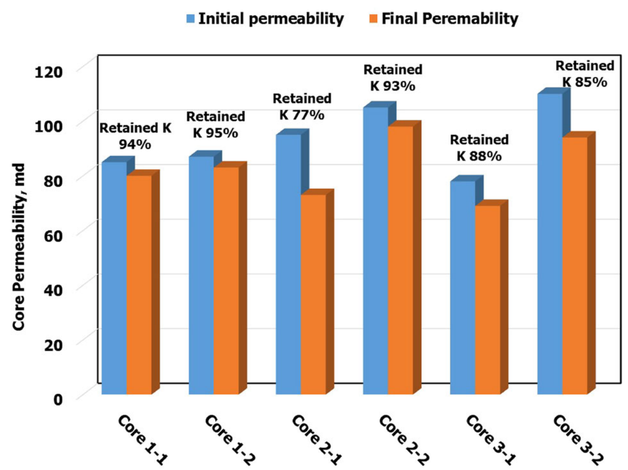

Fig. 4 Retained permeability of sandstone core after using Na_3-HEDTA as a stimulation fluid

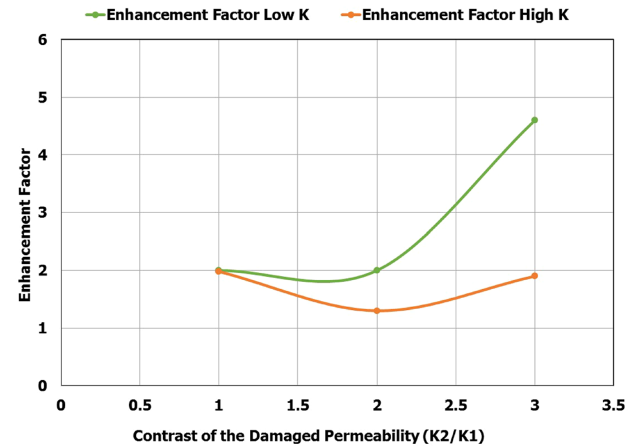

Fig. 5 Relationship between the damaged permeability contrast and the enhancement factor after the stimulation process

Table 5 shows the results of the three sets of experiments with permeability contrast 1, 2, and 3. The results of the first set with damaged permeability contrast ($K_{\text{core \#2}}/K_{\text{core \#1}} = 1$) showed almost the same retained permeability of 95% for both core samples. In the second set with damaged permeability contrast ($K_{\text{core \#2}}/K_{\text{core \#1}} = 2$), the results showed the ability of the treatment fluid to recover 93 and 77% of the original permeability of the high and the low-permeability core samples, respectively. Finally, the results of the last set ($K_{\text{core \#2}}/K_{\text{core \#1}} = 3$) confirmed the necessity of using this fluid as a diversion fluid. The ratio of the final permeability to the damaged permeability of the low-permeability core was 4.6, as shown in Table 5. Also, it gave a retained permeability of 88% of the low-permeability core and a retained permeability of 94% for the high-permeability core sample in set #3.

The data obtained showed that using Na_3HEDTA as a diversion fluid will significantly improve the stimulation process and remove the formation damage after drilling or completion processes in sandstone reservoirs. Permeability measurements showed the ability of Na_3HEDTA to stimulate heterogeneous sandstone cores without adding gelling materials at high temperatures. The enhancement of core permeability with low damage was about 94% and about 80% of the high damage cores. Therefore, this fluid will guarantee that the oil and gas production will be from the entire horizontal section.

Description of the diversion process in horizontal section

Mathematically, the obtained experimental results will be used to describe the process of diversion using Na_3HEDTA (20 wt%) in horizontal well based on the real permeability distribution along 4500 ft horizontal section, Fig. 2. The horizontal section has six parts with average permeabilities (37, 80, 62, 43, 90 and 50 md), respectively, form the heel to the toe.

Figure 5 shows the relationship between the enhancement factor of the permeability ($K_{\text{final}}/K_{\text{damaged}}$) after the stimulation using the diversion fluid, Na_3HEDTA, and the damaged permeability contrast ($K_{\text{core \#2}}/K_{\text{core \#1}}$). Based on this relation, the diversion mechanism in the horizontal section will be evaluated using two scenarios.

In the first scenario, the reservoir was divided into three sections; each section has a damaged permeability contrast, and the stimulation treatment was assumed to be performed in three separate stages. In this scenario, the evaluation of the stimulation and diversion mechanism of the cleanup fluid (Na_3HEDTA) was evaluated through each section separately, while in the second scenario, the stimulation fluid was injected in one stage and the diversion mechanism of Na_3HEDTA was evaluated through the damaged permeability contrast along the horizontal heterogeneous reservoir section.

For example for set #3 in which the permeability of the two cores were 50 and 15 md, the viscosity of the HEDTA at the first of injection was 1.5 cP at the test temperature. The pressure drop required in this case can be calculated as follows:

$$\Delta p = \frac{122.812 q \mu L}{k D^2} \tag{2}$$

where Δp is the pressure drop across the core, psi, q is the injection rate, cc/min, μ is the HEDTA viscosity, cP, L is the core length, inch (in our case it is 6 in.), and D is the core diameter, inch (in our case it is 1.5 in.). The pressure drop required to inject the HEDTA at the start of the experiment from the above equation is 10 psi; we collected the effluent samples, and the ICP (inductively coupled plasma) showed that the calcium concentration was

30,000 ppm and the viscosity of HEDTA at this concentration was 5.2 cP. Because of the increase in the viscosity, the pressure drop will increase to 34 psi. This increase in the pressure drop due to the viscosity buildup will divert the fresh fluid flow to the low-permeability core (15 md) because the required pressure drop in this case will be 32 psi. This process will continue until the fluid break through the two cores and both core permeabilities will be enhanced as mentioned earlier.

First scenario

The horizontal section was divided into three parts each part had different damaged permeability contrast set. The first part (from heel to 1500 ft) with an average damaged permeabilities of 37 and 80 md. The damaged permeability contrast ($K_{core\ \#2}/K_{core\ \#1}$) in this section was equal to 2.66, which was close to the third set of the experiment work (damaged permeability contrast of 3). Using the relation from Fig. 5, the enhancement factor for 80 md is 1.5 and for 37 md is 3.1. Based on the enhancement factor, after the stimulation treatment using Na_3HEDTA, the final permeability will be 120 and 115 md, Fig. 6.

The second part of the horizontal section has damaged permeabilities of 62 and 43 md, which is located between 1500 and 3500 ft with damaged permeability contrast of 1.45. The enhancement factor (using Fig. 5) is 1.5 for the 62 md and 1.9 for the 43 md. The final permeabilities after the stimulating process will be 93 and 82 md as shown in Fig. 6.

The permeability distribution through the last 1000 ft of the horizontal section is 90 and 50 md with a damaged permeability contrast ($K_{core\ \#2}/K_{core\ \#1}$) of 1.8. Applying the same concept, the final permeabilities after the stimulation treatment will be 117 md and 100 md as shown in Fig. 6.

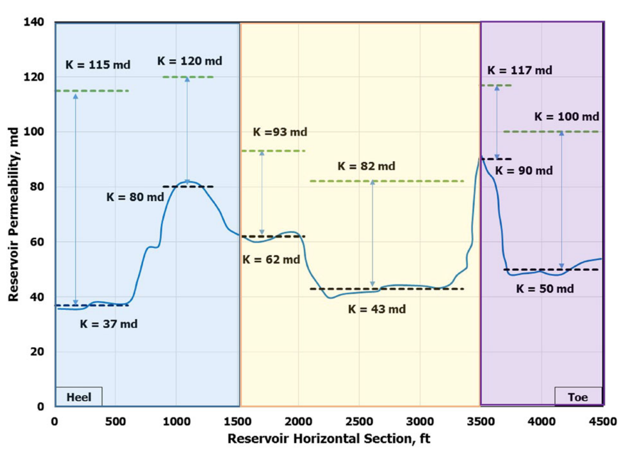

Fig. 6 Scenario 1: permeability distribution through the assumed three horizontal sandstone sections before and after the stimulation treatment using Na_3HEDTA

Figure 6 shows the permeability distribution along a horizontal section of a sandstone formation before and after the stimulation treatment using the diversion fluid, Na_3-HEDTA. The profile of the permeability shows a significant improvement of the low-permeability parts of the horizontal section.

Second scenario

In this scenario, the HEDTA chelating agent was injected to the open hole section in the horizontal well in one stage, which simulated the real situation in the field. Mathematically, due to the difference in the permeabilities of the horizontal section, the fluid will start stimulating the high-permeability sections.

Based on the diversion mechanism obtained from the experimental work, Na_3HEDTA will react with the carbonates in the sandstone formation and this reaction will produce high viscosity that will divert the flow of the fluid through the less permeable part in the horizontal sections.

In this scenario, the permeabilities of the horizontal section were sorted from the highest to the lowest as shown in Table 6. The damaged permeability contrast ($K_{core\ \#2}/K_{core\ \#1}$) between the high-permeability section and the next section is calculated in the second column of Table 6. The enhancement factor of the lateral's permeabilities after the stimulation treatments using the diversion fluid Na_3-HEDTA was determined using the correlation in Fig. 5.

The results in Table 6 show that there were some values of the permeabilities repeated as high- and/or Low-*K* part. The 80-md part was the low-*K* part compared to 90 md; therefore, the enhancement factors were 1.83 for the 90 md as a high-*K* core and 2 as a low-*K* core using damaged permeability contrast (K_2/K_1) of 1.125 in Fig. 5. After that the same part with 80 md was the high-*K* part compared to

Table 6 Case 2, final permeability calculation after stimulating the horizontal section using Na_3HEDTA

Sorted damaged *k*, md	Comments	Damaged contrast K_2/K_1	Enhancement factor (Fig. 5)	Final permeability, md
90	High-*K* part	1.125	1.83	164.7
80	Low-*K* part		2	160
80	High-*K* part	1.29	1.75	140
62	Low-*K* part		1.9	117.8
62	High-*K* part	1.24	1.75	108.5
50	Low-*K* part		1.95	97.5
50	High-*K* part	1.11	1.9	95
45	Low-*K* part		2	90
45	High-*K* part	1.21	1.8	81
37	Low-*K* part		1.9	70.3

62 md; thus, the enhancement factors were 1.75 for the 80 md as high-K core and 1.9 as a low-K core using damaged permeability contrast (K_2/K_1) of 1.29 in Fig. 5. The increase in enhancement factors (double their value) of some permeability values occurs only due to do the mathematical calculation; in reality, the permeability range of 80-md section after the stimulation treatment will be between 140 and 160 md with an average value of 150 md. Figure 7 shows the permeability distribution along the horizontal section of a sandstone formation before and after the stimulation using the diversion fluid, Na_3HEDTA based on the second scenario.

Figure 8 shows the comparison of the final permeability distribution of the two scenarios after the stimulation treatment. It is clear that the final permeability distribution profile in the second scenario is similar to the initial damaged permeability profile through the horizontal section. While, in the first scenario, the behavior of the initial permeability distribution through the horizontal section was close to the initial damaged permeability distribution behavior except in the first 700 ft as the damaged permeability contrast was high (around 2.66) and as a result, the enhancement factor was also high (3.1) for the low-permeability section (37 md). Also, through the last 500 ft (from 4000 to 4500 ft), the behavior of the final permeability was not close to the behavior of the initial permeability distribution because of the damaged permeability contrast was 1.8, which gave 1.9 enhancement factor for the low-permeability section.

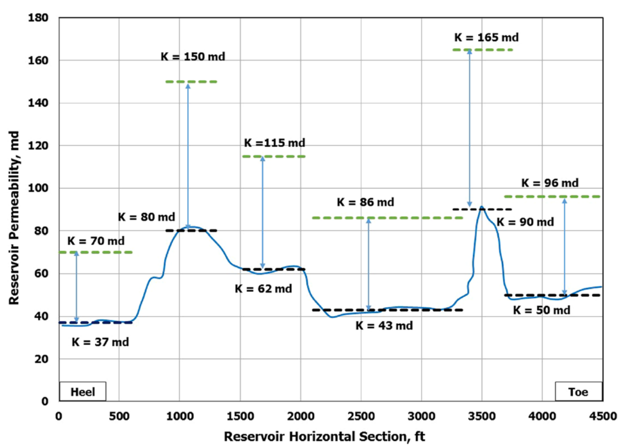

Fig. 7 Scenario 2: permeability distribution along the horizontal sandstone formation before and after the stimulation treatment using Na_3HEDTA

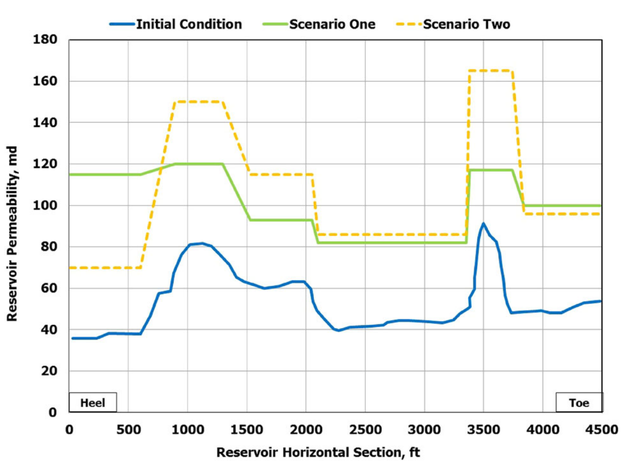

Fig. 8 Comparison of the final permeability distribution through the horizontal section after the two scenarios of stimulation treatment

Conclusions

In this paper, we introduced HEDTA chelating agent as a cleanup fluid for horizontal wells. HEDTA can clean up the well and remove the filter cake and damage due to drilling fluid in heterogeneous horizontal wells. HEDTA has the ability to divert itself through the low-permeability sections in the well due to the buildup in its viscosity after the reaction with calcium carbonate. Experimental results showed that HEDTA improved the permeability of both high- and low-permeability sections in the horizontal well based on two different scenarios. The first scenario is stage injection, in which the HEDTA is injected in three stages along the horizontal well. The second scenario is a continuous injection of HEDTA throughout the entire section in one stage. The analysis of both scenarios shows that HEDTA chelating agent can remove the damage from heterogeneous horizontal sandstone wells. HEDTA acted as an efficient divergent without using gelling agents up to permeability contrast of 3.

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