Field Treatment To Stimulate an Oil Well in an Offshore Sandstone Reservoir Using a Novel, Low-Corrosive, Environmentally Friendly Fluid

H.A. Nasr-El-Din, Texas A&M University; H. Dana and V. Tomos, Energean Oil & Gas; and T. Stanitzek, C.A. de Wolf, and A. Alex, AkzoNobel

Summary

Acidizing sandstone formations is a real challenge for the oil and gas industry. Fines migration, sand production, and additional damages caused by precipitation are some of the common concerns related to sandstone treatments. Furthermore, the complexities of sandstone formations require a mixture of acids and loadings of several additives. The environmentally friendly chelating agent glutamic acid N,N-diacetic acid (GLDA) was used successfully to stimulate deep gas wells in carbonate reservoirs. It was tested extensively in the laboratory to stimulate sandstone cores with various mineralogies. Significant permeability improvements were reported in previous papers over a wide range of conditions. In this paper, the result of the first field application is evaluated with a fluid based on this chelating agent to acidize an offshore, sour oil well in a sandstone reservoir.

The field treatment included pumping a preflush of xylene to remove oil residues and any possible asphaltene deposited in the wellbore region, followed by the main stage that contained 25 wt% GLDA, a corrosion inhibitor, and a water-wetting surfactant. The treatment fluids were displaced into the formation by pumping diesel. The treatment fluids were allowed to soak for 6 hours, then the well was put into production, and samples of flowback fluids were collected. The concentrations of key cations were determined using inductively coupled plasma, and the chelant concentration was measured using a titration method with ferric chloride solutions.

Corrosion tests conducted on low-carbon-steel tubulars indicated that this chelant has low corrosion rates under bottomhole conditions. No corrosion-inhibitor intensifier was needed. The treatment was applied in the field without encountering any operational problems. A significant gain in oil production was achieved without causing sand production, or fines migration. Analysis of flowback samples confirmed the ability of the chelating-agent solution to dissolve various types of carbonates, oxides, and sulphides, while keeping the dissolved species in solution without causing unwanted precipitation. Unlike previous treatments conducted on this well, where 15 wt% hydrochloric acid (HCl) or 13.5 wt%/1.5 wt% HCl/hydrofluoric acid (HF) acids were used, the concentrations of iron and manganese in the flowback samples were negligible, confirming the low corrosion rates of well tubulars when using GLDA solutions.

Introduction

Acidizing sandstone formations is a real challenge, mainly because of the presence of several minerals in sandstone. On the average, the composition of sandstone contains sand, carbonates, aluminum silicates, oxides, and sulphides. The reaction rate between acids and sandstones depends on the acid type and the mineral that needs to be removed. Most of the time, the acid that is preferred for the removal of a specific mineral cannot be used because it may be incompatible with another mineral present in the same reservoir. For example, if a sandstone reservoir is damaged by lost-circulation material (e.g., calcium carbonate), then the logical, cost-effective choice is to use HCl. However, if the same zone contains illite clay or zeolite, then HCl can cause severe damage (Mahmoud et al. 2015). HCl is not compatible with illites and zeolites. Another example occurs when organic acids are used and the formation contains smectite, a swelling clay. Acetic acid will cause swelling in smectite and can cause formation damage.

The selection of the proper fluid to be used in sandstone is also impacted by the metallurgy of well tubulars, especially at high temperatures. It is affected by the composition of crude oil and the presence of acidic gases carbon dioxide (CO_2) and hydrogen sulphide (H_2S). For example, for wells completed with corrosion resistant alloys, lower HCl concentrations should be used. Also, for low-carbon steels, pickling well tubulars is required if the acid is to be bullheaded. Finally, the presence of H_2S will require the addition of a H_2S scavenger if HCl or formic acid were used.

If the damage in sandstone reservoirs is caused by clays, then a form of HF-based acid should be used. These acids require a preflush to remove carbonates, oxides, and some sulphides. Regular mud acid (12 wt%/3 wt% HCl/HF) was the traditional acid used for sandstone reservoirs for years. Various HCl/HF ratios were suggested to minimize formation damage by the precipitation of reaction products with the rocks. Regular mud acid should be used if the damage is close to the wellbore. If the damage is deeper, a retarded HF acid should be used. Two main retarded acids were used in the field. The first was developed by Thomas and Crowe (1978), and was based on boric acid. The second, developed by Gdanski (1985), was based on AlCl₃.

One of the main problems with HF-based acids is sand production. The cementing material in sandstone is calcite, clays, or both. The first can be dissolved by HCl, whereas the second can be dissolved by HF. Both acids will dissolve the cementing material, which will result in sand production. A decrease in the acid concentration will help reduce sand production. Another solution is to use a chelating agent with HF. A chelating agent is significantly weaker than HCl or simple organic acids. Therefore, it will not dissolve the same amount of cementing material. The chelating agent will also complex with di- and trivalent cations to minimize their precipitation. One example of this type of system is phosphonic acid with HF (Rae and di Lullo 2003). Others used aminopolycarboxylic acids (APCAs) to stimulate sandstone formations (Ali et al. 2002, 2008; Parkinson et al. 2010).

Chelating agents were first used to remove calcium sulphate scale from sandstone formations at Prudhoe Bay (Shaughnessy and Kline 1983; Tyler et al. 1985). They have been used widely in carbonate stimulation as standalone stimulation fluids or as iron control agents. Fredd and Fogler (1997, 1998) were the first to evaluate chelating agents to stimulate carbonate and sandstone reservoirs. Frenier et al. (2001, 2003, 2004) used formulations

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Element	Concentration, wt%		Field Mixing		
С	0.24	lon	Seawater	Water	Produced Water
Mn	1.25	Na⁺	9,650	50	22,000
Si	0.2	K*	376	9	760
Cu	0.1	Ca ²⁺	392	65	770
Ni	0.05	Mg ²⁺	1,245	8	1,750
Cr	0.35	Sr ⁺²	_	-	17
Мо	0.1	Ba ⁺²	_	_	1
Fe	balance	Mn ⁺²	_	-	-
Table 1—Composition of L-80, low-carbon steel.		CI-	20,000	naª	36,000
		SO₄ ^{−2}	2.725	na	1.880

based on the hydroxyethylaminocarboxylic acid (HACA) family of chelating agents to stimulate high-temperature oil and gas carbonate and sandstone reservoirs. Their laboratory tests showed that HACA chelating agents stimulated carbonate formations effectively at high temperatures (250°F).

Ali et al. (2008) used a chelant-based fluid to stimulate sandstone reservoirs with high temperatures and carbonate contents. A significant increase in rock permeability was obtained with the fluid. Parkinson et al. (2010) used HEDTA at pH 4 to stimulate a multilayered sandstone reservoir with different carbonate contents and obtained positive field results.

LePage et al. (2011) introduced GLDA as a standalone stimulation fluid for carbonate reservoirs. Mahmoud et al. (2011a, b) conducted coreflood tests to optimize the concentration and volume of GLDA needed to acidize carbonate rocks at temperatures of up to 300°F. Braun et al. (2012) studied the health, safety, and environmental profile of GLDA. According to their studies, GLDA is nontoxic, and it is accepted for use in the North Sea. Nasr-El-Din et al. (2012) measured the corrosion rate of low-carbon steels with GLDA solutions that contained 20 wt% GLDA. Low concentrations of corrosion inhibitors for organic acids were needed to protect well tubulars (C-75 and L-80). Armirola et al. (2011) developed an acid system on the basis of a chelant, HF, and boric acid. They used it successfully to clean the gravel pack and address fines-migration problems.

Al-Harbi et al. (2013) examined the compatibility of calcium chloride, aluminum chloride with sodium EDTA, and HF acid. Aluminum fluoride was noted when the F/Al ratio exceeded a critical value. Reyes et al. (2013) tested a new biodegradable chelant that belonged to the APCAs. They studied the application of this chelant for acidizing sandstones. Their chelating agent was used at 0.6 mol/L in combination with HF, 0 to 2 wt%, to stimulate Berea and Bandera sandstone cores. They claimed that the new system minimized precipitation caused by HF reactions. Mahmoud et al. (2015) conducted coreflood tests with sandstone cores of various mineralogies. They tested GLDA/HF and HEDTA/HF acid systems with 20 wt% chelant and from 0.5 to 3 wt% HF. Poor results were obtained when HF concentrations exceeded 1 wt%. At HF concentrations less than 1 wt%, a significant increase in core permeability was noted.

From the previous discussion, GLDA was examined extensively in the laboratory with great results. It was also used in carbonate reservoirs with positive field results (Nasr-El-Din et al. 2013). This paper presents the first field application in an offshore sour oil well in a sandstone reservoir. The objectives of this paper are to (1) discuss the first field application of GLDA in an offshore sandstone reservoir and (2) evaluate this treatment on the basis of the analysis of the produced fluids following this treatment.

Corrosion Testing

Corrosion tests under downhole conditions were performed in a 1-L Buchi autoclave (maximum pressure = 1,500 psi), which contained a glass liner to prevent any other metal/acid contact, except for the test coupon itself. The thermocouple is also equipped with a glass liner. The subject well had tubulars made from low-carbon-steel alloys (C-75 and L-80). **Table 1** gives the elemental analysis of L-80. The weight and size of the test coupons were

Table 2—Analysis of the seawater used for injection, field mixing water, and the well-produced water just before the treatment. All concentrations are expressed in ppm.

na

2,185

^ana = not available.

200

HCO₃

measured accurately before the test; the coupons were cleaned with a paper towel and isopropyl alcohol before and after the test. The dimensions of the coupons were the following: length of 1/2 in., width of 3/4 in., and thickness of 1/16 in., with a 0.2-in. hole in the centre resulting in a total surface area of 0.9 in.² The total acid volume was 0.4 L, giving an acid-volume/coupon-surface-area ratio of 0.44 L/in.²

The corrosion rate was determined as the weight loss of the metal coupon after 6 hours at downhole conditions, because most treatments required approximately 6 to 8 hours of corrosion protection (Kalfayan 2008). An L-80 coupon was submersed in the chelant solution (25 wt% GLDA) and attached to a glass hook. After assembly and closure of the autoclave, the vapour space was purged three times with nitrogen (N₂) gas. The unit was then sealed and pressurized to 70 psig with hydrogen sulphide (H₂S). The pressure was then increased to 100 psig with CO₂ and then to 1,000 psig with N₂ to generate an approximate 7 mol% H₂S, 3 mol% CO₂, and 90 mol% N₂ in the vapour space. The pressure rose further to 1,000 to 1,200 psi.

As soon as the desired temperature was reached, a timer was started. A pressure greater than 1,000 psi was maintained during the entire test. After 6 hours, the autoclave was cooled with water to less than 150° F in 20 minutes. After cooling, the pressure was relieved and the unit purged with N₂ gas through a caustic-soda scrubber system (approximately 60 minutes). This step was performed to remove H₂S from the system. The unit was opened carefully, and the samples were retrieved. Before reweighting, the coupon was cleaned with a nonmetallic brush, washed with acetone, and dried. Spent acid was collected and analyzed with ICP to measure the concentrations of Fe and Mn ions. Photos of the coupons were taken after the corrosion testing.

Field Case

A vertical oil well in an offshore, sour sandstone reservoir was damaged because of blocked perforations. The perforations were damaged by calcium carbonate particles that were used in a workover that was performed in this well. There was a need to stimulate this well to increase the well production rate. Previous acid treatments conducted in this field included 15 wt% HCl or 13.5%/ 1.5% HCl/HF mud acid. However, using these acids in this well was a concern because of the age of the well, the conditions of well tubulars, and the presence of sour gases. The well produces sour gases with 7 mol% H₂S and 3 mol% CO₂. The target zone contained sand, feldspar, small amounts of kaolinite, illite, and trace amounts of calcite and dolomite, with an average porosity of 19 vol% and a permeability of 180 md. The sand particles in this reservoir were cemented by calcareous and argillaceous materials. The field was under seawater injection, and the composition of the seawater is given in Table 2. The well was producing water at a water cut of 90 \pm 1 vol%, and the concentrations of key ions in the produced water only before the treatment are given in Table 2.

Parameter	Corrosion Rate, lbm/ft ²
Without corrosion inhibitor	0.168
With 1 vol% corrosion inhibitor	0.0044

Table 3—Corrosion rates for L-80 coupons with 25 wt% GLDA solutions with and without 1 vol% corrosion inhibitor. The test was performed at 260°F, 7 mol% H₂S, and 3 mol% CO₂, and the test period was 6 hours.

The well was perforated with a perforation density of 4 shots/ft at 60° phasing. The length of the target zone was 125 ft. The well tubulars were made of C-75 and L-80; both were made from low-carbon steel. A gas lift was being used to produce this well, and oil production before the treatment was approximately 207 B/D. The depth of the target zone was approximately 9,323 ft. The gas mandrel was located at 3,323 ft, and the injected gases contained methanol, nitrogen, CO₂, and a small concentration of H₂S.

Treatment Program

This field case represented a real challenge for the following reasons:

- 1. High bottomhole temperature (257°F).
- 2. The presence of H_2S and CO_2 at significant concentrations.
- 3. The well has been on production for more than 32 years, and tubular conditions were a serious concern.
- Strict limitations on the chemicals used because of environmental issues.
- 5. The well was located offshore, and space available for storing and mixing chemicals was limited.
- 6. Production logs were not available. Therefore, water-producing zones were not known before the treatment.

A matrix treatment was designed to cope with the challenging well conditions, the strict environmental legislation of the region, and space limitations. The treatment included three main stages. The goal of the first stage was to remove possible asphaltenes and residual heavy hydrocarbons from the wellbore region. A total of 86 bbl of xylene was used. It was left to soak for 4 hours. The second stage was the main treatment, which contained 25 wt% GLDA, 1 vol% corrosion inhibitor, and 0.2 vol% water-wetting surfactant. A total of 188 bbl of the chelant-based fluid were injected into the target zone. The intent of this step was to remove any blocking particles from the perforations caused by workover interventions performed in the past. The third stage included pumping diesel to displace the treatment fluids from the wellbore into the target zone. The volume of diesel was equal to the volume of the wellbore (i.e., 81.5 bbl). The treatment was applied by bullheading, and the injection rate (3 bbl/min) was monitored to avoid exceeding the fracture pressure of the formation. The fracture gradient was 0.75 psi/ft. The well flowback was started after 6 hours of soaking time. Samples of produced fluids were collected as a function of time; the aqueous phase was separated and then analyzed to assess the outcome of the treatment. A total of 53 samples were collected over 35 hours.

Methods Used To Analyze Well-Flowback Samples

During the flowback of the well, samples of the produced liquids were collected every 10 to 15 minutes. Sampling intervals increased gradually and reached 3 hours in the last few samples. The samples contained hydrocarbons and aqueous phases. The latter was separated and analyzed to determine the concentrations of various cations. Also, the concentration of the chelant in the aqueous phase was measured by titration using a ferric chloride solution (Sokhanvarian et al. 2012).

ICP emission spectroscopy (ICP-ES) was used to determine the concentrations of key cations. A portion of each homogenized sample was digested with 70 wt% nitric acid for 40 minutes at 240°F (116°C) in a heating block (Digiprep). All samples were analyzed by a radial viewed ICP-ES, with scandium as the internal standard.

Results and Discussion

Results of Corrosion Testing. Table 3 gives the corrosion rates for coupons of the L-80 with and without 1 vol% corrosion inhibitor. Corrosion tests were performed at 260°F for 6 hours under N2 atmosphere that contained 7 mol% H₂S, and 3 mol% CO₂. In the absence of the corrosion inhibitor, the corrosion rate for 6 hours of corrosion testing was 0.168 lbm/ft², significantly higher than the industry-accepted limit for low-carbon steel (0.05 lbm/ft²). A corrosion inhibitor was needed to protect well tubulars. The corrosion inhibitor was designed to protect tubulars from organic acids, and it contained alkoxylated fatty amines, alkoxylated organic acid, and thiourea N,N' dibutyl. The corrosion rate in the presence of 1 vol% inhibitor was significantly less than the acceptable limit for low-carbon steel. Table 4 gives the concentrations of Fe and Mn in spent fluids obtained after the corrosion tests. The concentrations of Fe and Mn were significantly higher if no corrosion inhibitor was used. Iron concentration decreased once a 1 vol% of the inhibitor was used. Fig. 1 shows photos of two coupons of L-80 after corrosion testing at 260°F for 6 hours. No pitting or discolouration was observed if the corrosion inhibitor was used, whereas severe pitting was noted if no inhibitor was used.

Visual Inspection of the Flowback Samples. The samples collected from the treated well did not contain sand particles or fines. This observation indicated that GLDA was compatible with sandstone minerals, and it did not cause sand-production or finesmigration problems. It should be mentioned that the operator conducted compatibility tests with the crude oil and the treatment fluids. No emulsion or asphaltene was noted. The samples collected from the field did not contain emulsions or asphaltene, further confirming that GLDA at a pH of 3.8 was compatible with this asphaltic crude oil.

Fig. 2 shows pictures of the aqueous phase separated from the flowback samples that were collected after the treatment. The colour of the aqueous phase separated from the samples ranged from light to dark yellow. These colours indicated the presence of various iron species.

Analysis of Well-Flowback Samples. Fig. 3 shows that the pH of the aqueous phase had separated from the flowback samples. The pH of the main treatment was 3.8. The pH started at 4.1, increased gradually to approximately 8, and then remained constant. It is important to note that the pH was measured several weeks after the treatment. Therefore, the actual pH could have been slightly lower than the reported data. This is because of the release of acid gases, H_2S and CO_2 , from the samples. The pH of the produced fluids ranged from 4 to 8. Therefore, facilities upset was not a concern. Also, this range indicated a lower corrosion rate for the well tubulars, as will be discussed later.

The concentrations of sodium and potassium ions are important. They can be used to track the flow of the treating fluids after the treatment. The produced water before the treatment contained 22,000 ppm sodium and 760 ppm potassium (Table 2). The main treating fluids contained 48,000 ppm sodium and 33 ppm potassium. The main source of sodium in the treating fluids was the chelant, where monosodium GLDA was used. **Fig. 4** shows the concentrations of sodium and potassium ions in the flowback

Parameter	Concentration of Iron Ion, mg/L	Concentration of Mn Ion, mg/L
Nithout corrosion inhibitor	2100	2.3
Nith 1 vol% corrosion inhibitor	60	0.6

Table 4—Concentrations of iron and manganese in spent fluids after corrosion testing.



Fig. 1—Two L-80 coupons after corrosion testing at 260° F with 7 mol% H₂S and 3 mol% CO₂. The coupon on the left was tested without corrosion inhibitor, and the one on the right was tested with 1 vol% corrosion inhibitor.



Fig. 2—Flowback samples after the treatment. Yellow colour indicates the presence of various iron species.



Fig. 3—The pH of the aqueous phase that was separated from the flowback samples that were collected after the treatment.



Fig. 4—Concentrations of sodium and potassium ions in the flowback samples.



Fig. 5—Concentration of sulphur in the flowback samples. Sources of sulphur included sulphide, sulphate, and H_2S that were present in the produced gases.

samples. The initial sodium ion concentration ranged from 41,000 to 42,000 ppm, and then it decreased gradually to 21,000 ppm, which was close to its value in the produced water before the treatment. Potassium started at 83 ppm and increased gradually to 760 ppm. On the basis of these results, it took approximately 365 minutes to produce most of the treatment fluids from this well.

The subject well is sour, with 7 mol% H₂S. It is of interest to follow sulphur concentration in the flowback samples. Fig. 5 shows the variation of sulphur concentration in the flowback samples. Sulphur can be present in one or more of the following forms: sulphide, sulphate, and/or organic sulphur. The sources of sulphide are H₂S, which is already present in the produced fluids, and that produced by dissolution of iron sulphide in GLDA. Sulphate source is the produced water that contained 1,880 ppm sulphate. Organic sulphur is present in the corrosion inhibitor used to protect well tubulars during pumping of the GLDA solution. The concentration of the sulphur started at 660 ppm, increased to a maximum of 1,600 ppm, declined to 740 ppm ppm, then increased gradually, and finally reaches approximately 1,500 ppm. These changes in the sulphur concentration can be explained as follows. The subject well produced gases that contained 7 mol% H₂S and a water cut of approximately 90 vol%. The tubulars were made of L-80, low-carbon-steel alloy. It is most likely that the wellbore region contained iron sulphide species before the treatment. Therefore, the initial increase in sulphur concentration was caused by the dissolution of iron sulphide. The final increase in the sulphur concentration was



Fig. 7—Concentrations of total iron and manganese ions in the flowback samples.



Fig. 6—Concentrations of calcium, magnesium, and aluminum ions in the flowback samples.

caused by sulphate ions present in the produced water, which contained 1,880 ppm sulphate or 627 ppm sulphur.

GLDA was used in the treatment to remove the calcium carbonate particles that were used as a lost circulation material. **Fig. 6** shows the concentrations of calcium, magnesium, and aluminum in the flowback samples. The formation contains minor amounts of carbonate minerals. As a result, the main source of calcium and magnesium ions from the start of the flowback to 365 minutes was mainly the lost circulation material. Calcium ion concentration reached 4,500 ppm, whereas magnesium reached 3,000 ppm. Their concentrations approached their values gradually in the produced water. The aluminum concentration is also shown in Fig. 6. The loss circulation material used in this well did not contain aluminum; therefore, the main source of aluminum were the feldspars and clays that were present in the formation.

Fig. 7 shows the concentrations of elements that are related to corrosion. On the basis of the analysis given in Table 1, the two main ions of interest for low-carbon steel are Fe and Mn. The Fe and Mn were present in the flowback samples at extremely low concentrations, showing that the treatment had no significant impact on the integrity of well tubulars. These data can be used to calculate average corrosion rate during the treatment. The amounts of Fe and Mn dissolved during the treatment can be obtained by finding the area under the curves in Fig. 7, sample density, and flowback rate. The total amount of Fe and Mn present in the flowback samples was found to be 17.146 lbm. The average corrosion rate can be obtained by dividing the amount by the inside area of the tubing (inside diameter = 2.992 in. and length = 9,323 ft). The average corrosion rate was found to be 0.0023 lbm/ft², which is on the same order of magnitude as the corrosion rate determined in the laboratory.

Analysis of GLDA Present in the Well-Flowback Samples. An extensive analysis was conducted on the aqueous phase present in the well flowback samples. The objective was to determine the fate of this chelant under downhole conditions. The GLDA concentration in the aqueous phase of each sample was measured by titration with a FeCl₃ solution (Sokhanvaian et al. 2012). The concentration of GLDA in the main treatment was 25.4 wt%, which was slightly higher than the planned concentration of 25 wt% GLDA. The concentration of GLDA in the produced fluids (Fig. 8) was lower than that in the main treatment. The reduction in the concentration of GLDA was mainly caused by the dilution of the treating fluids with the formation brine. The GLDA concentration decreased gradually and reached 1 to 2 wt% after 365 minutes. This time period was comparable to the time taken for other ions to reach their levels in the produced brine. Fig. 8 also shows the cumulative weight of Na-GLDA recovered in the well flowback samples. The total amount of GLDA recovered was found to be 88%. This number is reasonable because the last



Fig. 8—Concentration and cumulative amount of GLDA recovered in the produced fluids.

GLDA concentration measured was 1 to 2 wt%. A higher recovery would be expected had we continued collecting more samples from the well.

Fig. 9 shows the pH of the flowback samples in addition to the amount of GLDA that was complexed to any of the metal cations measured by ICP analysis. A fully effective treatment in carbonate formations would show more than 80% complexation of the GLDA solution (Nasr-El-Din et al. 2013). During this treatment, the flowback analysis showed that the percentage of chelated product in the first 100 minutes was low, which indicated that all calcite and dolomite had already been dissolved by the GLDA solution that was pumped into the sandstone formation first and

flowed back later. The pH confirms a gradual increase in complexation of GLDA because with an increase in carbonate dissolution, the pH would increase from 3.8 to approximately 4 to 5 in. carbonate formations. The last flowback samples show a chelation percentage greater than 100% caused by the mixing with formation water that contained calcium and magnesium ions (Table 2).

Treatment Results. Fig. 10 shows the oil-production rate as a function of time before and after the treatment. The oil production of the subject well improved from 207 std B/D and stabilized after some fluctuations in approximately 5 weeks to 243 std B/D.



Fig. 9—Percentage of complexed GLDA and the pH value of the flowback samples.



Fig. 10—Oil production before and after the treatment.

Consequently, after 60 days, the additional production as a result of the treatment was 2,307 bbl.

It is important to mention that the treatment fluid was bullheaded with no means for diversion. Also, the water-producing zones were not known before the treatment. There is great possibility that some of the treating fluids invaded water-producing zones

Fig. 11 shows water cut before and after the treatment. Water cut slightly increased after the treatment from 90 to 92–93 vol%.



Fig. 11—Water cut before and after the treatment.

and caused this slight increase in water cut. In addition, no sand was produced, indicating that the treatment removed the damaging material without destabilizing the formation.

Previous treatments with HCl or mud acid showed pinholes, and the gain in well performance lasted for 2 months. In addition, several additives were needed to protect the tubulars from these strong acids and to prevent asphaltene precipitation. The treatment with GLDA showed no pinholes, and the treatment lasted close to 6 months. The treatment maintained the integrity of the old tubulars and did not cause fines migration or asphaltene or emulsion problems.

Conclusions

GLDA was used to stimulate a deep, sour oil well in an offshore sandstone reservoir. On the basis of field results and extensive analysis of well-flowback samples, the following conclusions can be drawn:

- 1. Analysis of the flowback samples showed that the treatment did not affect the integrity of the old well tubulars.
- GLDA did not cause sand production or fines migration. GLDA was compatible with reservoir rocks.
- 3. GLDA did not cause a loss of productivity as a result of asphaltene precipitation or the formation of emulsions and sludges.
- 4. The well responded positively to the treatment, and the outcome of this treatment was better than those treatments where HCl or mud acids were used.

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Hisham A. Nasr-El-Din is a professor and holder of the John Edgar Holt Endowed Chair at Texas A&M University in Petroleum Engineering. Previously, he worked for 15 years as Principal Professional and Team Leader of the Stimulation Research and Technology Team at Saudi Aramco. Before joining Saudi Aramco, Nasr-El-Din worked for 4 years as a staff research engineer with the Petroleum Recovery Institute in Calgary. He also worked as a research associate with the University of Saskatchewan, the University of Ottawa, and the University of Alberta. Nasr-El-Din's research interests include well stimulation, formation damage, enhanced oil recovery, conformance control, interfacial properties, adsorption, rheology, cementing, drilling fluids, two-phase flow, and nondamaging fluid technologies. He holds more than 20 patents, wrote 15 book chapters, and has published and presented more than 600 technical papers. Nasr-El-Din has received many awards within Saudi Aramco for significant contributions in stimulation and treatment-fluid technologies and stimulation design, and for his work in training and mentoring. He holds BS and MS degrees from Cairo University in Egypt and a PhD degree from the University of Saskatchewan, all in chemical engineering. Nasr-El-Din is a review chairperson for SPE Journal, and is a technical editor for SPE Production & Operations and SPE Drilling & Completion. He has been invited to give keynote presentations in various SPE and National Association of Corrosion Engineers conferences. Nasr-El-Din received the SPE Regional Technical Discipline Award for Production and Operations in 2006, was named a Distinguished SPE Member in 2007, and received SPE awards for Outstanding Associate Editor (SPE Journal) and Outstanding Technical Editor (SPE Production & Operations) in 2008. In addition, he received the SPE Production and Operations Award and Outstanding Associate Editor Award (SPE Journal) in 2009. Nasr-El-Din received the SPE "A Peer Apart" status in 2011 for reviewing more than 100 papers. He was named the 2013 recipient of the SPE Distinguished Achievement Award for Petroleum Engineering Faculty.

Halina Dana is a production technologist at Energean Oil & Gas. Previously, she was a production engineer in Petróleos de Venezuela S.A. Dana's research interests include flow assurance, well stimulation, and production optimization. She holds

a BS degree in chemical engineering from the Rafael Urdaneta University in Venezuela.

Vassilis Tomos is a well-interventions and production superintendent at Energean Oil & Gas. He has been with the company for 12 years. Tomos's current interests include well site engineering, completion, artificial-lift design and applications, well testing, pressure surveys, and log interpretation. He holds a MSc degree in petroleum engineering from Heriot-Watt University.

Theo Stanitzek currently works at AkzoNobel Specialty Chemicals and is responsible for the oilfield chemicals business within AkzoNobel. He has worked in the chemical industry more than a decade and has introduced new chemical technologies successfully in various application areas, including the oil field. Stanitzek is a certified business economist in Germany and has training in the area of technology marketing.

Corine A. de Wolf is Senior Technical Marketing Manager Oil and Gas with AkzoNobel (Deventer, The Netherlands). Her main fields of interest include the properties and application of chelate-based formulations in oil and gas applications. Previously, de Wolf worked as a project leader at the AkzoNobel Chelates R&D laboratory (Arnhem, The Netherlands), with a special focus on the functionality and properties of chelates in cleaning, micronutrients, oilfield applications, and food fortification. She holds an MSc degree in chemistry from Utrecht University and a PhD degree in heterogeneous catalysis and surface chemistry from Leiden University, both in the Netherlands. de Wolf holds more than 20 patents and has authored or coauthored more than 40 technical papers on various subjects. She is a member of SPE, has been a member of an SPE conference program committee, and has presented at several SPE workshops.

Alan K. Alex is a chemical engineer by training and is currently working as Development Manager of oilfield chemicals at AkzoNobel. He has coauthored several technical papers in the area of acidizing and corrosion control. Alex holds a degree in chemical engineering from Lehigh University and a Masters degree from Institut Européen d'Administration des Affaires in France.

