Well Stimulation

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Redefining Success in Well Stimulations

This feature highlights three papers that are examples of working smarter, better, or cheaper to help us be more competitive in an ever-growing world energy market. In 2004, oil and gas production was the leading supplier of energy generation with approximately 55% of the world market. Four key competitors made up more than 44%: coal, nuclear, hydroelectric, and biomass/waste. It would seem that new competitors continue to appear.

One major E&P company is touting its lead as the largest producer of magma-heated steam to drive power generators—enough to support millions of homes. The water captured after power generation is reinjected and reheated to temperatures as high as 570°F, completing a renewable-energy cycle. Then there is the latest liquid-sodium-cooled nuclear power plants, such as the "Toshiba 4S." Additionally, others are pushing solar, wind, bitumen, and now power plants that can switch between coal and natural gas. As the price of oil climbs, our competitors will catch up all the quicker to meet the world's growing energy needs.

Now is the time to raise the bar for defining well-stimulation success, not after our competitors have caught up. Is it possible that we spend too much time looking at future wells and not enough quantifying past results? Let us take the example of stimulating a four-fold increase in production, which generates a high economic return. If we determine that we could have achieved a six-fold increase with a greater return, or perhaps even a 20-fold increase by combining with a multistage-treated horizontal well, does this alter our idea of success?

It is time to take stimulation effectiveness to the next level, being measured and understood more reliably through integrated and detailed approaches. Success should be demonstrated through consistent engineered improvements. It is defining a greater understanding from previous stimulations that will allow us to realize more rapidly what is possible, thereby increasing our level of competition in a world market, one well at a time. **JPT**

Well Stimulation additional reading available at the SPE eLibrary: www.spe.org

SPE 110707 *• "Real-Time Diversion Quantification and Optimization Using DTS" by Gerard Glasbergen, SPE, Halliburton, et al.*

SPE 111512 *• "Innovative Water-Shutoff Solution Enhances Oil Recovery From a West Venezuela Sandstone Reservoir" by Goran Andersson, PetroBoscan, et al.*

Through-ESP Stimulation: A Cost-Effective Alternative

A major disadvantage of electrical submersible pumps (ESPs) is that they block access to well re-entry for surveillance and through-tubing intervention. One case of the latter is acid stimulation. In Petroleum Development Oman (PDO), acid jobs have been carried out as part of workovers to retrieve the pumps first. The cost implication can be large, ranging from USD 250,000 to 400,000. Two deployment techniques were adopted in PDO recently, bullheading acid into the reservoir through an ESP and spotting acid through coiled tubing (CT) into the reservoir; by so doing, 80 to 93% of comparative cost was saved. The techniques involved the use of abrasion-resistant ESPs for vertical wells and an ESP bypass (Y-tool) for CT deployment in horizontal wells.

Introduction

The X field in Oman is a sour, low-pressure carbonate formation 600 m deep and under natural depletion since the early 1970s. The field suffered a sharp pressure decline early, leading to installation of gas lift in all wells. By the mid-1990s, the remaining producers were converted to ESP wells because of gas-supply constraints. Gross production increased by more than 200%, and water cut increased from 50 to 80% at that time. A total of 18 wells are completed in this carbonate formation, which includes three cased horizontal and two openhole observation wells. By 2006, only four of these wells were producing, with an 80% average water cut. X-field wells are characterized by high productivity indices (PIs) of 1 to 4 $m^3/(kPa \cdot d)$, mainly a result of an active fracture network and faulting. Almost all matrix-completed wells did not produce, causing all production to be from the fracture and fault network.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 112315, "Through-Pump Stimulation: A Cost-Effective Alternative," by ***K.I. Ojukwu,*** *SPE, Petroleum Development Oman, prepared for the 2008 SPE International Symposium and Exhibition on Formation Damage Control, Lafayette, Louisiana, 13–15 February. The paper has not been peer reviewed.*

Game Change

Several matrix wells had been treated with acid after drilling and before production but still did not produce sustainably. To obtain the best results from acid treatments, spent acid should be removed from the well soon after the treatment, which usually is not a problem in wells that produce naturally. However, in low-pressure wells completed with pumps such as ESPs, post-stimulation acid pumpout is hardly possible and has not been a standard practice. This game change was necessary to exploit matrix production in the X field and would mean developing new ways to deploy acid effectively at a reasonable cost and yet with capability to pump out spent acid in time to avoid further reaction or damage (within 1 to 2 hours).

For an existing ESP well, one possible technique was to recomplete with a new ESP and a Y-tool to provide bypass required to isolate the pump while deploying acid by means of the Y-tool. However, the cost associated with this technique is quite high. An alternative cost-effective approach is to bullhead acid through the ESP without the need for a workover. A cost analysis and comparison were made to make the business case and evaluate risk. This cost was based on a 10-m treatment interval and 600-m well depth.

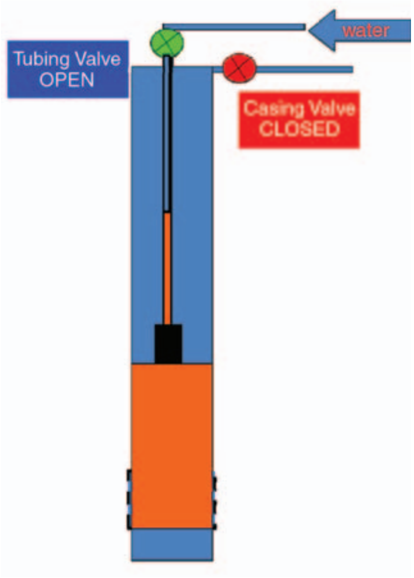

Fig. 1—Spotting acid into Well X-17 wellbore.

In 2006, Well X-17 was converted from an openhole matrix observation well to a cased-hole producer. It was cemented, logged, perforated, and recompleted with an abrasion-resistant ESP with a variable-speed drive (VSD) for rate adjustment. An abrasion-resistant ESP was selected in case this well was in a tight or damaged matrix so that an acid stimulation could be performed. This was not standard practice because most wells in the X field are drilled into the fault or fracture network and require no stimulation. As anticipated, after recompletion, the well did not produce because of poor inflow. With the use of a surface VSD, the well was able to flow approximately 20 m^3/d (instead of the 500-m^3/d design rate) for 3 days, sufficient time to obtain a stable downhole pressure. The brief production showed good oil cut of approximately 90% with a

0.005 $m^3/(kPa \cdot d)$ PI. A skin value of 20 was estimated (using a 10-md known core matrix permeability), suggesting the absence of fractures and presence of severe matrix damage. On the basis of this result, the decision was made to acid stimulate the well, which if successful, would demonstrate the possibility of matrix production from existing wells and perhaps for new matrix infill wells also. The question was, Could acid be bullheaded safely through an ESP to stimulate carbonate reservoirs?

Well X-31 is a horizontal appraisal well drilled and completed in 2006 with an ESP and Y-tool for the primary purpose of providing openhole logs and production logs. The Y-tool is a bypass tool run with an ESP to provide access and seal to logging tools. After completion, it was detected that the well was pumping off. The reason was found to be excessive high-viscosity-pills injection during the drilling to quell losses. The injected pills were too heavy to be lifted by the ESP, which was designed originally to handle a 10-kPa/m formation fluid gradient. The decision was made to try to improve inflow by stimulating the carbonate matrix, to break down the pills and flush them out, and to treat the near-wellbore damage.

Pump Selection

A standard ESP usually is not abrasion-resistant unless abrasion is predicted and a special pump requested. The expectation of solids flowback after the acid job led to the inclusion of an abrasion-resistant ESP in the completion design. Most ESP providers keep an in-house specification of pump tolerance level for acid. The ESP supplier was informed of the objective and specified a pump with a 15% acid threshold as its tolerance limit. This special type of pump is made of tungsten carbide alloy that protects the pump internals from acid and wear from solids. The pump also has special shafts and bearings built to withstand low-to-moderate abrasion. On the basis of this tolerance level, the first through-pump bullhead acid stimulation was designed with a 15% acid formulation. Although the vendor specified a 4-hour maximum exposure time, the technique design limits the pump exposure time to 10 to 15 minutes.

Acid

A 15% inhibited hydrochloric acid (HCl) was formulated for placement. The acid concentration was designed to fall within the tolerance limit of the ESP. Experience with carbonate reservoirs suggest that 1 m^3 of acid per meter is adequate to create enough wormholes needed to overcome the damage without creating short-circuiting channels into the fracture network or water zone. A 10-m^3 total acid volume was considered sufficient for Well X-17. The total cost of stimulation and pumping service was approximately USD 7,000.

Vertical ESP Well

The major problem of bullheading acid through the ESP in Well X-17P was the possibility of damaging the pump impellers. But this problem was mitigated by the installation of an abrasion-resistant ESP during the 2006 completion and through implementation of an innovative deployment practice. The additional upfront cost of selecting an abrasion-resistant ESP was approximately USD 10,000.

The risks facing this operation included the following.

- U-tubing of acid up the casing, which may damage the casing/tubing/pump assembly without achieving desired objective.
- Damage to ESP internal seals, bearings, and impellers if exposed too long to acid.
- The challenge to spot all of the acid into the formation and not in the wellbore or annulus.
- Producing all spent acid back within a reasonably short period of time (1 hour).
- Good cement bond.

To minimize these risks while achieving the required objectives, the following novel deployment approach was adopted.

1. Pump water through the tubing to fill up tubing and annulus at a given rate (higher than outflow rate). Note that outflow rate into reservoir should be quite low because of high skin.
2. Flush until fluid gets to surface.
3. Spot 4 m^3 inhibited-HCl mixture to displace tubing volume up to ESP while circulating through annulus faster to minimize time of exposure.
4. Secure annular compartment by closing annulus wing valve at surface to trap water in annulus while continuing to pump.
5. Continue acid displacement until entire 10 m^3 of acid is delivered into the well **(Fig. 1).**
6. Space out acid with 12 m^3 (two times well volume) of water to ensure all acid is displaced into formation.
7. Wait for 1 hour, and then switch on ESP to flush out spent acid and clean up well.

The effect of a successful acid job is revealed by the significant increase in intake pressure (meaning high inflow), reduced intake temperature (a result of better pump cooling), and gradual increase in temperature over some days (a proof of subsequent cleanup). The well was tested 1 week later with an improved PI of 0.05 $m^3/(kPa \cdot d)$ at an increased production rate of 134 m^3/d gross with 128 m^3/d of net oil.

Acid Placement by CT Into a Horizontal ESP Well

Stimulating a horizontal well presents a different and difficult challenge because the acid placement must be engineered carefully to avoid a localized treatment. Because high volumes of acid usually are required for horizontal sections, the occurrence of localized placement can result in extensive wormholes that can connect to the fracture network or faults. CT was used to spot the acid along the horizontal path while pulling the injection nozzle out of the hole. However, to deploy CT in a horizontal ESP well, a Y-tool is necessary. In Well X-31, the ESP was installed with a Y-tool for production logging. CT could be deployed through the Y-tool to inject fluid while pumping. The program for deployment was planned as follows.

1. Run CT to 10 m below ESP/Y-tool tail pipe. Use Y-tool CT plug to prevent leak between CT and Y-Tool.
2. Pump water through CT at a high rate to fill up annulus to surface.
3. Close annulus wing valve while still pumping.

4. Switch on the ESP to flush well by means of annulus while slowly running CT in the hole to well total depth (TD).
5. Reopen annulus wing valve.
6. Stop ESP, and inject acid rapidly to fill up CT.
7. Close annulus wing valve.
8. Start to pull out of hole with CT while injecting inhibited acid at 0.05 m^3/m. Spot a total of 37.5 m^3 inhibited acid to fill 750 m of $6^1/_8$-in. open hole.
9. Space out with 10 m^3 of water, and wait for 1 hour.
10. Run CT back to TD while injecting water at 0.05 m^3/m.
11. Pull out of hole and rig down CT.
12. Turn on ESP to clean out and produce well.

Although the job was planned properly, it was impossible to run the CT past an obstruction at 792 m. After several failed attempts to re-enter past the obstruction, The decision was made to abort the program at Step 4. The acid was spotted at this holdup depth, yielding an improvement of 75 m^3/d of net oil and 150 m^3/d of gross production (50% water cut). However, this production was short-lived because the high-viscosity pills filled the well again. The treatment will be repeated after repairing the well. Although uncompleted, this trial proved the well viable and of high potential, justifying well-repair activity.

Conclusions

Stimulation through an ESP is possible and economically effective. This technique is also fit-for-purpose for better stimulation effectiveness in low-pressure carbonate reservoirs such as those in the X field because the time between stimulation and cleanout is controllable and can be limited to 1 to 2 hours, which is not the case in workovers.

These cases mark the first attempt in PDO to implement the techniques, which was made possible by the low unit technical cost (UTC) and by ease of application. Conducting the trials has opened new opportunities for reviving many closed-in matrix wells in the X field, which otherwise would not be considered worth exploiting. In addition, it has become a best practice worth replicating in similar circumstances across the organization. Since the acid treatment, Well X-17 has been producing at the lowest water cut of all X-field wells. At USD 0.5/bbl UTC and 7,000 per job, there is not much to lose with this approach. **JPT**

Interactions of Iron and Viscoelastic Surfactants: A New Formation-Damage Mechanism

Viscoelastic-surfactant (VES)-based acids have been used extensively in the last few years in matrix- and acid-fracturing treatments. The results from one treatment were below expectations. Analysis of the live acid used indicated that this acid contained nearly 10 000 mg/L total iron. This study was conducted to provide a better understanding of interactions between iron and VESs.

Introduction

The existence of iron in the stimulation process is almost a given in every step of the treatment. Therefore, the interaction of iron with acid additives should be examined carefully. Acid additives that were introduced recently are VESs. These surfactants (amphoteric, anionic, or cationic, or combinations of these types) are used to divert the acid in carbonate formations. Amphoteric and cationic surfactants contain function groups that can interact with iron. The full-length paper examines the effect of ferric ion (Fe^{3+}) on amphoteric- and cationic-based VESs.

When stimulating a carbonate, the acid, mostly hydrochloric acid (HCl), will react with calcium carbonate ($CaCO_3$) to produce calcium chloride ($CaCl_2$) and increase the pH value. The increase in pH value will transform the special micellars into long rod-shaped ones. This transformation is accompanied by a significant increase in fluid viscosity.

It is very important to measure the effect of Fe^{3+} on the viscosity of VES solutions because Fe^{3+} is expected to be significant during well treatment; iron concentration could be as high as 100 000 mg/L. Also, it is important to study the formation of various ferric species with VESs. The presence of iron can affect the behavior and function of VES-based fluids adversely. Therefore, the objective of the present study is to examine potential interactions between Fe^{3+} and two categories of VES that have been used in the field: amphoteric and cationic VES.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 112465, "Interactions of Iron and Viscoelastic Surfactants: A New Formation-Damage Mechanism," by ***A.R. Al-Nakhli,*** *SPE, Saudi Aramco;* ***H.A. Nasr-El-Din,*** *SPE, Texas A&M U.; and* ***A.A. Al-Baiyat,*** *King Fahd U. of Petroleum and Minerals, prepared for the 2008 SPE International Symposium and Exhibition on Formation Damage Control, Lafayette, Louisiana, 13–15 February.The paper has not been peer reviewed.*

Sources of Fe^{3+}

During acidizing treatments, the acid can be contaminated with iron compounds at all stages. Rust in storage tanks and mixing tanks can be dissolved by the acid and produce a mixture of iron(II) and Fe^{3+}. However, dissolved oxygen in the acid will oxidize iron(II) to Fe^{3+}. Large amounts of iron in live acids can result during acid injection as the acid dissolves mill scale in new tubing or corrosion products. Iron content was measured in an acid solution at four different points in the acidizing process. Iron content at the wellhead varied from 200 to 3500 mg/L, and the returning acid showed iron concentrations of 9000 to 100 000 mg/L during cleanup treatments of new wells. Moreover, thin deposits of iron sulfide scale on tubing can result in large quantities of iron(II) in solution during an acid treatment. Also, the formation brine may have iron in solution.

Fig. 1—VES precipitate.

Experimental Studies

Materials. Ferric chloride hexahydrate, $CaCO_3$, and concentrated HCl (37 wt%) were obtained from Fisher Scientific (American Chemical Society grade) and were used as received. $CaCO_3$ was used in this study to represent reservoir rock. The concentration of HCl was determined by titration, and the acid was used with distilled water to prepare acid solutions. Acid solutions with additives were prepared such that the final acid concentrations were 3 or 20 wt% HCl.

Corrosion inhibitors and VESs were oilfield chemicals and were used as received. Mutual solvent (2-butoxyethanol) was used to dissolve gel-like material that formed from VES and Fe^{3+}.

Procedure. VES-based acids were prepared such that the final solution contained 6 vol% surfactant, 3 or 20 wt% HCl, and 0.3 vol% corrosion inhibitor. Ferric chloride was added to these solutions at various concentrations.

Equipment. A Fann Model 35 viscometer was used to measure the apparent viscosity of acid solutions at

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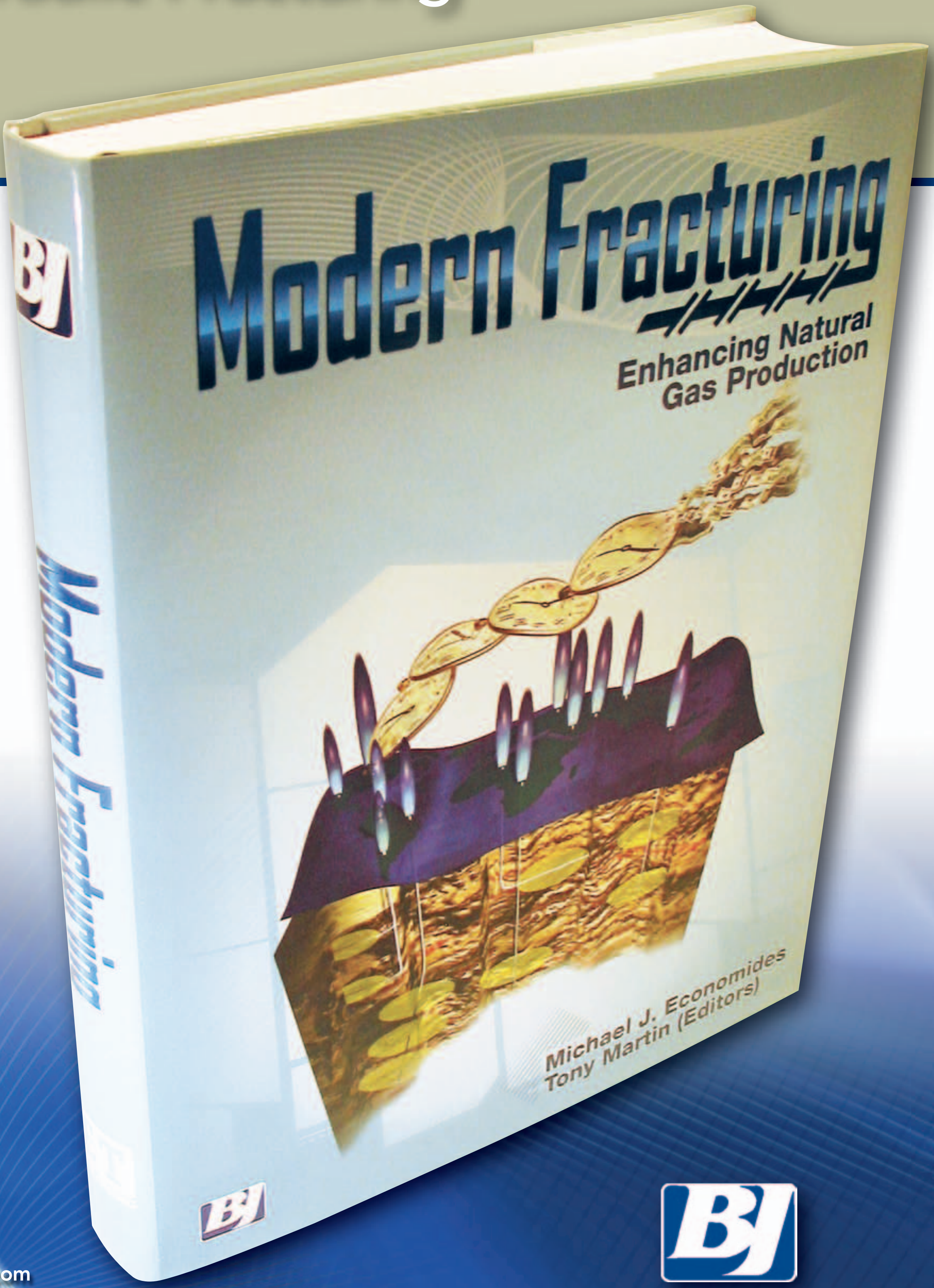

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Written in 2007 by a team of industry experts and edited by Michael J. Economides, petroleum engineering/strategy consultant and professor at the Cullen College of Engineering, University of Houston, and Tony Martin, BJ Services business-development manager for international stimulation.

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room pressure and temperature. A pH meter was used to measure the pH of tested solutions. Elemental analysis was carried out by use of inductively coupled plasma mass spectrometry, scanning electron microscope (SEM), and X-ray diffraction.

Results and Discussion

Precipitation of VES by Fe^{3+}. The surfactants used in this study were cationic and two different amphoteric VESs. The effect of Fe^{3+} on the apparent viscosity and Fe/VES complex formation was studied. The three types of VESs examined showed an initial increase in viscosity, phase separation, and then precipitate of VES caused by Fe^{3+} **(Fig. 1).**

The complex formation of Fe^{3+} with VES is pH-dependent because the complex formation is controlled by the availability of free ligands and free Fe^{3+} species. The distribution of ferric species shows that free Fe^{3+} species are dominant at low pH values (i.e., in acidic solutions). At high pH values, $Fe(OH)_3$ is dominant, which is not suitable to form ligands with VES molecules. Fe^{3+} will be present in solution at a pH value of zero. Then the Fe^{3+} will start to precipitate at a pH value of 1 and almost complete precipitation by a pH value of 2.

The results showed that Fe^{3+}, in the presence of VES, caused an increase in acid viscosity and phase separation and eventually caused a precipitate of VES in the form of a gel-like material at pH zero. The same trend was noted in the presence of the corrosion inhibitor.

Ferric species are suitable to complex with VES at low pH values by forming ligands with –N and/or –COO-. The experimental work showed that the addition of ferric chloride to VES solution resulted in an increase in viscosity, phase separation, and precipitation of VES at high Fe^{3+} concentrations.

The results also show a direct effect of ferric-species concentration on VES fluid viscosity. As Fe^{3+} concentration was increased in solution, the viscosity of VES-acid solution increased. However, at higher Fe^{3+} concentrations, phase separation and eventually precipitation of VES were noted. Because VES was precipitated by ferric ions, the supernatant of the acid did not form a gel upon neutralization with $CaCO_3$. Therefore, Fe^{3+} is very harmful to VES-based acids, and every effort should be made to minimize contamination of acids with Fe^{3+}.

Effect of Fe^{3+} on the Apparent Viscosity of VES-Based Acid at 3 wt% HCl

Amphoteric VES. For amino acid VES, the experimental results showed that the increase of Fe^{3+} concentration caused an increase in VES-solution viscosity, reaching a maximum viscosity at 300 ppm of Fe^{3+}. Then the viscosity decreased to reach the minimum, with phase separation at 10 000 ppm.

The results also showed that the corrosion inhibitor by itself caused an increase in VES-solution viscosity.

Cationic VES. Cationic (quaternium) VES had a lower viscosity than amino acid. However, Fe^{3+} caused an increase in solution viscosity, but no phase separation was observed. The corrosion inhibitor clearly minimized the effect of Fe^{3+} on viscosity. The VES viscosity increased gradually with the increase of Fe^{3+} concentration and reached the maximum at 10 000 ppm of Fe^{3+}.

Gel-Like Form of VES With Fe^{3+}. Various phases were seen in VES-based acids in the presence of Fe^{3+}. Mixing of acidic solutions containing Fe^{3+} and VES increases the solution viscosity and gives a heterogeneous system consisting of a gel-like precipitate and a liquid phase. The stability of the formed gel-like material is strongly dependent on the pH of the solution. Upon increasing the solution pH, the ferric-VES gel will dissolve.

The presence of Fe^{3+} in the precipitated material was analyzed by an environmental SEM. The analysis showed the presence of Fe^{3+} in the gel samples. This is clear evidence that there was a chemical interaction between the surfactant and iron ions.

Effect of Fe^{3+} on the Apparent Viscosity of VES-Based Acid at 20 wt% HCl. At a 20 wt% HCl concentration, the initial viscosity of the VES solution was lower than at 3 wt% HCl. However, the fluid viscosity increased with the increase of the Fe^{3+} concentration. A phase separation occurred at 1300 ppm, with a sharp decrease in solution viscosity. Then, there was a precipitate of VES at 3000 ppm of Fe^{3+} and higher. As more iron was added, the precipitated material agglomerated. Eventually, the precipitated material formed a large sludge at 10 000 ppm of iron.

Effect of Corrosion Inhibitor. The corrosion inhibitor minimized the effect of Fe^{3+} on the apparent viscosity. The results showed less increase in VES viscosity, as a result of addition of Fe^{3+} with the corrosion inhibitor in solution. However, the viscosity of VES increased with the increase of iron concentration; moreover, the solution forms a gel at 700 to 900 ppm of Fe^{3+}. There was no clear phase separation at 1300 ppm, as occurred when no corrosion inhibitor was used. However, there was a precipitate at 3,000 ppm of Fe^{3+}, with a sharp decrease in solution viscosity.

The solution color was red-brown at 100 ppm. However, the color changed to greenish at 200 ppm and orange at 300 ppm. Then the color changed to dark brown for higher Fe^{3+} concentrations.

There was a reddish precipitate at the bottom of the solution as Fe^{3+} was added to solution. The amount of precipitate increased with increasing Fe^{3+} concentration. At 3000 ppm of Fe^{3+}, there was another precipitate, because of VES, at the bottom of the solution with a drop in solution viscosity. Some of white sludge was noticed in the solution at 100 and 200 ppm of Fe^{3+}.

At 3 wt% HCl concentration, the corrosion inhibitor caused an increase in VES-solution viscosity; the initial viscosity increased by almost 100 cp. However, this was not the case at 20 wt% HCl concentration where the VES solution with corrosion inhibitor had a lower viscosity.

Conclusions

1. The apparent viscosity of VES-based acids increased at low Fe^{3+} concentrations.
2. VES precipitated at higher iron concentrations.
3. The precipitate is a complex that contained iron and VES.
4. Higher iron concentrations can interfere with various VESs and cause precipitation of gel-like material that can cause formation damage. JPT

New HF-Acid System for a Heavy-Crude Brownfield With Fines Problems

Minimizing fines migration and improving high-water-cut-well productivities with improved treatment-fluid designs, detailed candidate selection, and enhanced pumping methods yielded positive results in aged-field production enhancement. A slow-release-hydrogen retarded-hydrofluoric-acid (SRH-RHF) system was used on the basis of a detailed candidate selection, case-specific fluid design for high-water-cut wells, and mechanism of fines and clay migration and control methodology to acidize heavy- or medium-crude reservoirs.

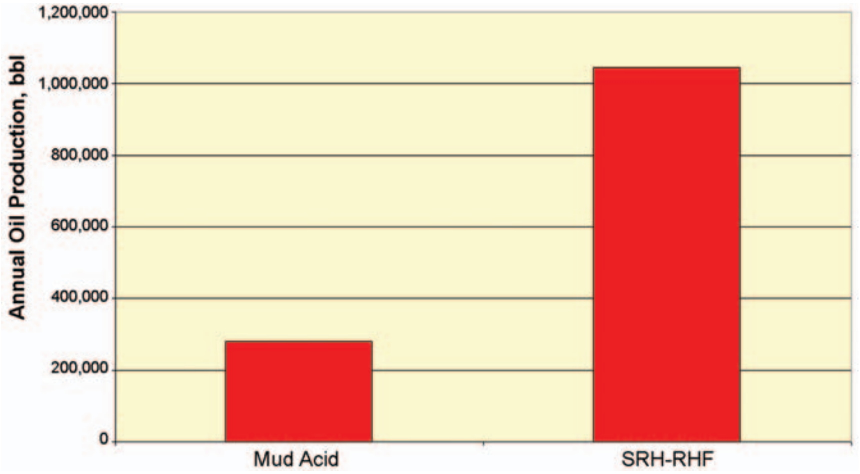

Fig. 1—Champion West CC-well concept.

Introduction

Improving productivity in these Niger delta brownfields that produce heavy crude and experience fines migration had been approached with little or no consideration to such challenges as water production. Many wells were treated with a conventional mud-acid system, either with or without a solvent-soak treatment. Clay-control agents are no longer used to stop fines problems because the additive had little effect. Wells with high water cut were treated only with solvent material, realizing minimal effect. Foam diversion often had inconsistent results. Other diverting techniques also proved unpredictable in this environment. A coating of heavy crude on the formation wall inhibited the reaction of the mud-acid system with the formation. An acid system or formulation that would maintain matrix acidizing was needed for well-productivity problems in the Niger delta.

In December 1996, an SRH-RHF system was used. Data indicated a consistent production increase with evidence of deep penetration into the damaged zone. Failures experienced with this system were traced to a shortage of well information for proper diagnosis and the need for a core-flow test in one field with three treatments resulting in no increase or a reduction in production.

In the past, acid stimulation was limited to wells with water cut less than 30%. In late 2001, an improvement was made in candidate selection, treatment design, foam diversion, and pumping method for high-water-cut wells and heavy-crude wells. The high-water-cut limit was increased to 60%. In 2005, a new SRH-RHF system was developed. Its application in nine wells with heavy or medium crude was successful.

Reservoir Description

The Niger delta basin is a prolific hydrocarbon province covering 80,000 sq km. Wells treated with the new SRH-RHF drain eight different reservoir sands. Most of the treated sands consist of several sequences of shale and sandstone with mostly medium-to-poorly consolidated sands. The sandstones are fine-to-medium quartz; poorly-to-moderately sorted smectite, kaolinite, and illite clays; with feldspathic and carbonate scale materials. Permeabilities of the treated intervals ranged from 500 to 2,000 md, and well bottomhole static temperatures ranged from 125 to 163°F.

Well Completion

Most of the operator's oil wells are dual producers, typically completed with $2^3/8$- to $3^1/2$-in. tubing in a perforated cased hole or gravel packs with wire-wrapped screens inside perforated casing.

Damage

Production impairment is believed to be heavy-hydrocarbon precipitation, clay swelling, fines migration, wettabil-

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This article, written by Technology Editor Dennis Denney, contains highlights of paper SPE 112558, "Increasing Production in a Brownfield With Heavy Crude and Fines Problems by Application of New HF-Acid System: Case Histories," by ***Folorunso Afolabi,*** *SPE,* ***Austa Opusunju,*** *SPE, and* ***Jaspers Henri,*** *SPE, Shell, and* ***Cletus Onyekwere,*** *SPE,* ***Chris Onyekwere,*** *SPE, and* ***Davalos Juan,*** *SPE, Weafri, prepared for the 2008 SPE International Symposium and Exhibition on Formation Damage Control, Lafayette, Louisiana, 13–15 February. The paper has not been peer reviewed.*

ity alteration, and, to a lesser extent, hydrate formation and treatment-fluid damage. Associated damage mechanism may be scale deposition caused by filtrate invasion, especially in wells with high water cut, with occasional problems with emulsions and formation-/treatment-fluid incompatibility.

Fines Migration. Fines are quartz or clay particles smaller than 44 µm. The origin of fines is multiple and complex, thus making it prevalent in most oil fields. Damage caused by fines migration often is worsened by associated-water production, high oil viscosity, and crude-oil gravity. Fines cause damage by blocking pore throats and acting as nucleation particles for heavy-hydrocarbon deposition and emulsion stability.

Reservoir-Fluid-Flow Rate. There is a critical fluid-flow rate beyond which the hydrodynamic force exceeds the binding forces holding fines particles together, and the fines begin to move. A sudden increase in flow rate also could induce fines migration, such as when choke sizes are changed or not designed properly. Intermittent gas lift and uncontrolled flowback after stimulation can induce fines migration. In the case of kaolinite, illite, and nonclay fines that are attached loosely to formation pores, exceeding the critical flow rate will dislodge and migrate fines.

Wettability. Particle wettability and interfacial forces influence particle mobility. With multiphase flow, particles will move only when the wetting phase moves. Because fines and clays often are water-wet, water production or back-produced water-based treatment fluids likely will cause fines to dislodge and induce mobility. When only oil is flowing, little or no fines migration exists.

Acidizing. Injection of water-wetting treatment fluids or surfactant/solvent can mobilize fines that are held in place by wettability phenomena or interfacial forces.

Two-Phase Flow. Simultaneous flow of water and oil will cause fines to migrate because water is mobile enough to dislodge the fines. Local pressure disturbance caused by multiphase flow keeps fines agitated and reduces the opportunity to develop permanent bridges.

Medium/Heavy Crude. Many of the studied wells produce heavy crude with gravity between 22.3 and 10°API. The challenges encountered in acidizing heavy crude include high sludge tendency from treatment-/formation-fluid incompatibility, resulting in a high tendency for emulsion production after acidizing. Also, viscous crude could inhibit treatment fluids from reacting with damaging material if the treatment fluid is not properly designed.

The resulting low production or insignificant oil gain often is caused by poor candidate selection, possibly through improper or poor well analysis. The high-viscosity heavy crude often limits most HF treatments, especially a nondeep-penetrating HF system, to the near-wellbore region where most of the HF system is spent on clays having very large surface area compared to quartz.

Control/Design

Candidate selection involves analysis of the production-performance history, experience with heavy-crude behaviors, and good analytical skills. A full systems analysis can establish the extent and severity of the damage. Also, the gas/oil ratio, tubinghead pressure, water and gross-fluid production, bottomhole-pressure (BHP) trend, type of (removable) skin damage, information on nonremovable damage, and reservoir pressure are considered in the analyses to assess adequately the feasibility of acidizing. Most of the treated wells are within a screening envelope for matrix stimulation. This screening includes economical remaining reserves, productivity index (PI) <10 (obtained from BHP survey), a flow efficiency (ratio of actual to ideal PI) <0.5, and PI decline >30%. Good knowledge of the water source is important in high-water-cut-well stimulation. A full systems analysis, including cement-bond and porosity logs and production and permeability profiles, is carried out to establish the source of water and severity of the damage. Interval mineralogy, reservoir/damage permeability, and frequency and previous acid stimulations are considered.

Nodal Analysis. To confirm the presence of impairment and to characterize potential improved production from these candidates, nodal-analysis simulations were run in three stages.

- Pressure/volume/temperature matching enables accurate prediction of fluid properties during vertical lift.
- Gradient analysis obtained from correct pressure and test data helps to determine the appropriate wellbore correlation for the prediction of bottomhole flowing pressure.
- Systems analysis quantifies damage and defines the range of expected production increase.

Fluid Choice. It is necessary to evaluate the fluid pumped into the formation to determine the treatment formulation. In many low-pressure wells, diesel oil or a diesel/xylene mixture is used for a prestimulation injectivity test. However, the oil-phase fluid can cause problems when the near-wellbore water saturation is high (as in high-water-cut wells). The oil-phase fluid will cause the formation to become more oil-wet and will occupy the pores in water-producing zones. The effect is reduced oil mobility, increased water and fines mobility, and destabilizing the foam pad placed to divert the acid system from the water zone or high-permeability zones. The new approach uses a water-wetting 3% ammonium chloride (NH_4Cl) salt solution for the injectivity test. Approximately 10 to 20 bbl in excess of the coiled-tubing (CT) or tubing volume is used. This water-wetting fluid acts as a hole-conditioning fluid before foam-pad placement. NH_4Cl is compatible with most formations and with acid and foam systems. When injectivity is low, acid is spotted with CT and injectivity is repeated.

Fluid Design. Fluid design (or acid recipe) depends on the damage mechanism and results of core-flow tests if available. Usually, production impairment in the treated reservoir sands was the result of fines migration and, to a lesser extent, clay dispersion and swelling. A conventional acid recipe was designed with a solvent soak for reservoirs with heavy oil or a history of organic deposits (e.g., wax, asphaltene, and paraffin). The pumping sequence [solvent soak (an oil phase flowed back before foam or acid), foam, foam pad, and then acid] resulted in destabilizing the foam in the near-wellbore region. Use of a soak treatment, without flowback before pumping, retained foam stability and helped displace or push back the fines. The modified sequence [solvent (oil-phase injection with a wetting agent and no flowback), foam, foam pad, and then acid] minimized possible foam contamination by the organic solvent.

Placement and Diversions. Several diversion techniques improve treatment-fluid placement into the zone of interest. Mechanical techniques include straddle packers, wash cup, and ball sealers, while chemical techniques use viscous fluids, foam solutions, and oil-soluble resin. Because the pumped fluid will take the path of least resistance, it is vital to select the placement method and diversion techniques carefully for stimulating high-water-cut wells.

Most of the studied wells are in highly permeable heterogeneous reservoirs with a gravel pack across producing intervals that range from 10 to 50 ft long. Acid placement in a few of the wells was carried out with CT, while most jobs were performed by bullheading treatment fluid into the formation. Foam diversion was used in selective stimulation of oil zones preferential to water zones and to aid the effective distribution of treatment fluids in zones with a perforated interval greater than 15 ft.

Identifying the water source or point of inflow into the wellbore is essential in designing the foam pad for diverting acid from the water zone. Matrix stimulation of intervals having water influx from high-permeability zones in a heterogeneous reservoir will benefit more from foam diversion. Treatment of a reservoir in which water influx is from a low-permeability zone (water encroachment or mature coning effect) or zones with homogeneous permeability could be achieved by increasing the foam pad. In this case, the foam is expected to degrade faster in the oil phase. The volume of foam required is estimated at 25 to 30% of main treatment volume, and 65- to 70%-quality foam was used.

Maximum Safe Injection Rate and Pressure. The formation-fracture pressure (or maximum surface-pumping pressure) is considered in the decision. Use of CT is preferred with long intervals (greater than 200 ft) having a permeability contrast greater than 300 md. Preference also is given to the use of CT for horizontal wells with zones longer than 400 ft. Bullheading at maximum safe pressure is a suitable approach to short-string-interval stimulation when the CT cannot access that portion of the wellbore. The rate available through the CT can be limited especially in some high-production intervals with high water cut. Most fluids (even foam pad) pumped through CT degrade before acid injection as a result of the long pumping time at the low rates and accompanying high CT pumping pressure, leading to stimulation of the water zone and reduction in acid-penetration depth. A successful treatment was achieved with the combination of high-rate pumping (bullheading) of treatment fluids and foam diversion.

During high-rate and foam-diversion operations, production tubing is pickled with 10% hydrochloric acid. The pickling fluid usually is nitrified and lifted out of the tubing (with a plug set in the deepest nipple profile) to prevent ferrous scales and rust from contaminating the stimulation recipe or entering the formation.

New Retarded-HF System. Retarded acid is a slow-reacting acid system or an acid system with a controlled rate of reaction. This slowed reaction with formation-damaging material enables deeper penetration into damaged zones and prevents formation of damaging byproducts.

The SRH-RHF system is formed both at the surface and in-situ. The HF is generated through slow release of hydrogen ions by an organic salt, acid, or ester compound with multiple hydrogen atoms capable of ionizing into solution for replacement reaction or endothermic reaction. The delayed release of hydrogen assists in deep penetration of the formation.

In 2005, a new acid system was developed that generates HF from the reaction between ammonium bifluoride and an ester compound with multiple hydrogen ions. The release of the hydrogen ion from this ester is governed by pH changes, first at the surface and later in-situ. The consumption of one hydrogen ion will shift the equilibrium and, thus, release additional hydrogen ions to balance the system. The end product of the ester compound is a good wetting agent. Its slow reaction reduces fines size and allows longer reaction time on the formation without deconsolidation.

Laboratory Analysis and Fluid Selection. Field trial by the operator of any new acid system is allowed after detailed core-flow tests and fluid-compatibility tests confirm that the new acid system is better than a conventional acid system. Core-flow-test results of the SRH-RHF system proved that the retarded-acid system has superior performance over regular mud acid. However, for all the treatments carried out, compatibility tests between treatment fluid and formation fluids were conducted and recipes were modified until the sludge and emulsion tendency was eliminated. Fluids were not pumped until a clean mixture was observed in each case, indicating no insoluble precipitates formed when commingled.

Analysis

Of the 10 intervals analyzed for this paper, seven were heavy crude and two had medium crude. They also had water cuts between 17 and 36%. Seven of these stimulation candidates had been treated earlier with mud acid before the application of the new SRH-RHF system. The importance of selection of placement methods, injection-fluid types, and recipe designs also was part of the analysis.

Technical Comparison. All of the heavy-crude wells treated with this new approach demonstrated a significant increase in PI; longer productivity; and reduced, or minimal increase in, water cut after the treatment. Skin damage was removed in most cases, while true stimulation (negative skin) was recorded in two cases. The partial success experienced in one case could be attributed to poor planning that led to keeping spent acid in the critical near-wellbore region overnight because of a lack of liquid nitrogen and loss of lift gas. The reduced water cut and sustained production seen in most of the wells were the result of the effectiveness of foam diversion and high-rate pumping along with high-water-wetting, scale-inhibition, and deep-penetrating characteristics of the SRH-RHF system and fines stabilizer.

Economic Comparison. Fig. 1 shows that wells treated with this technique had considerable incremental production compared with marginal gains from previous techniques used on the same wells. The wells treated with the new SRH-RHF system paid back faster (within 20 days) than previous mud-acid treatments (100 days). The full-length paper details the treatments and results of the nine heavy- and medium-oil intervals. **JPT**