Carbonate sequences, those comprising limestone and dolomite formations, present some of the most difficult challenges facing field operators. Carbonate reservoirs often have large and highly variable completion intervals, which can greatly complicate stimulation and production operations. In many cases, these reservoirs exhibit marked vertical and lateral heterogeneity caused by permeability barriers, natural fractures, and complex porosity distributions. These variations can be particularly bewildering for engineers who are trying to devise effective workover and stimulation strategies.

In this article, Steven Davies and Shrihari Kelkar examine the techniques and technologies that field operators can use to stimulate carbonate reservoirs.
When the productivity of a well in a carbonate reservoir decreases as a result of formation damage or low natural permeability, the production team will attempt to increase productivity through intervention and appropriate treatments. If they decide to work over the well, they must identify and implement a treatment program that creates conductive flow paths between the reservoir and the borehole. This is the essence of carbonate stimulation.

Almost two-thirds of the world’s remaining oil reserves are contained in carbonate reservoirs. Carbonate formations tend to be extremely heterogeneous, with complex porosity and permeability variations, barriers, and irregular flow paths. Across the oil and gas industry, geologists, petrophysicists, and reservoir engineers are working to enhance their understanding of carbonate formations and reservoir behavior. There is a clear commercial focus to these research efforts; experience has shown that even small improvements in recovery methods can yield dramatic production results. Schlumberger is focusing its carbonate research and technology development on three critical areas: characterization, simulation, and stimulation. This article focuses on the last of these—increasing the productivity of carbonate reservoirs through better intervention and stimulation treatments.

For many years, reservoir teams have sought to extend the useful lives of wells in carbonate reservoirs and to avoid early abandonment when productivity decreases as a result of formation damage or low natural permeability. In clastic reservoirs, a range of stimulation techniques can be applied with a high degree of confidence, and asset teams routinely intervene to create conductive flow paths. Although many of these standard stimulation methods can be applied in carbonate reservoirs, it may be difficult for engineers to predict how they will influence subsequent production.

A stimulating environment

Acids play a key role in boosting production or increasing injectivity in oil and gas fields. Stimulation of carbonate rocks usually involves a reaction between an acid and the minerals calcite (CaCO₃) or dolomite CaMg(CO₃)₂ that is intended to enhance the flow properties of the rock. Modern acid stimulation systems can be controlled and targeted to achieve specific aims for the asset team. Stimulation methods in carbonate sequences can be divided into two main groups: matrix treatments and acid fracturing treatments.

Matrix stimulation involves pumping acids, solvents, or other treatment chemicals into the formation at less than the reservoir fracture pressure. When acids are introduced into a carbonate formation, some of the minerals in the rock dissolve, which creates intricate, high-permeability channels or wormholes (Fig. 1). Matrix treatments are often applied in zones with good natural permeability to counteract damage in the near-wellbore area.

Acid fracturing stimulations, in contrast, are performed above the fracture pressure of the formation. A viscous pad (a fracturing fluid that does not contain proppant) is pumped into the formation at pressures above the fracture-initiation pressure, which fractures the rock. Then an acid stage is pumped to etch the fracture surfaces. The acid also creates conductive wormholes at or near the fracture surfaces. After stimulation, the fracture closes, but the increased conductivity between the formation and the well remains because of the etching and the creation of wormholes.

Matrix stimulation in carbonates

Matrix stimulation methods can be applied in clastic or carbonate rocks. It is designed to remove or bypass damage in the pore spaces and to leave the zone barriers intact (Fig. 2). In sandstones, matrix treatments are used to restore or improve the natural formation permeability around the wellbore by removing formation damage. This is accomplished by dissolving material that is plugging the pores or by enlarging the pore spaces. In carbonates, matrix stimulation creates new, highly conductive channels (wormholes) that bypass the damage.

Because of these different requirements, the selection criteria for the treating fluid are also distinct. For sandstone rocks, it is vital that the stimulation engineer understands the extent, type, location, and origin of the damage, the reservoir mineralogy, and the compatibility of the treating fluid with the formation. In carbonate treatments, reservoir temperature, pumping rate, and fluid type become more significant because these parameters have a direct influence on the reaction between the treating fluid and the reservoir rock.

In carbonate reservoirs, hydrochloric acid (HCl) is the most commonly applied stimulation fluid. Organic acids such as formic or acetic acid are used, mainly in retarded-acid systems or in high-temperature applications, to acidize either sandstones or carbonates.
Acid fracturing

Acid fracturing is a hydraulic fracturing treatment performed in carbonate formations. The objective is to etch the open faces of induced fractures using an HCl treatment (Fig. 3). When the treatment is complete and the fracture closes, the etched surfaces provide high-conductivity flow paths from the reservoir to the wellbore.

Hydraulic fracturing of clastic rocks, in contrast, uses a propellant to hold the fracture open and so create a high-permeability flow path along which fluids flow into the well. To reduce or prevent leakoff (loss of treatment fluids to the formation), conventional acid fracturing treatments use multiple stages of nonreactive fluids and acids. This is designed to minimize the leakoff by increasing the fluid viscosity. By increasing the acid’s viscosity, the stimulation engineer can also slow the rate of reaction between the acid and the formation, which helps to improve fracture geometry. Viscosity can be modified by adding a polymer to the treatment fluid. This technique has proved successful in many oil fields, but the polymers form a filtercake that can reduce production, especially in tight formations.

Crosslinking compounds are used to control viscosity. These are usually metallic salts mixed with a base-gel polymer fluid, such as a guar gel system, to create a viscous gel. The crosslinker reacts with the multiple-strand polymer to couple the molecules and create a fluid with high, but closely controlled, viscosity. The behavior of the crosslinkers, which enable the polymer system to operate in a narrow pH window, can be difficult to predict at high temperatures. Treatments using crosslinkers should take account of the conditions needed to break the gel structure to ensure satisfactory cleanup and disposal.

When selecting the most suitable fluid for acid fracturing, engineers must take into account factors such as the proposed fracture geometry, the expected leakoff and retardation rates for the acid, rock dissolution, prevention of sludge or emulsion problems, and the requirements for postjob cleanup. Engineers must weigh the costs and these technical factors against the benefits of sustained production improvement.

Acid fracturing increases well productivity in Kuwait

A carbonate reservoir in the Jurassic Marrat formation in southeast Kuwait had been in production since 1986. The reservoir had no stimulation history because the oil had flowed naturally since completion. Recently, however, production had started to decline, and, as a result of reservoir depletion and the high-pressure drawdown applied in the formation, asphaltene deposits had affected some of the wells.

A production enhancement project was devised to improve well performance by reducing the pressure drawdown and so eliminating asphaltene deposition in the near-wellbore area. After carefully examining the production data and reservoir stress characteristics, the asset team decided that fracturing would be the best way to achieve these objectives. The team examined all the wells in the field and selected four of them for a pilot project.

To gain experience and understanding, the team designed an acid fracturing treatment for one well, based on well data and an evaluation of well performance. The treatment was designed to achieve a 70-ft fracture half-length and a fracture conductivity of 1,600 mD·ft. The analysis of the well was based on a permeability model obtained from a buildup test and a stress model built with Dipole Shear Sonic Imager data from an offset well. The stress and permeability models were calibrated by conducting an injection test, including a step-rate test and mini-falloff injection tests to estimate permeability and reservoir pressure, before the main acid fracturing treatment.

The DUOFRAC II acid fracturing technique, which uses acid and gel in alternate stages, was applied. The treatment was scheduled in two stages using a ClearFrac HF system as the nonreactive pad, 15% HCl as the main acid, and VDA® Viscoelastic Detergent Acid as the diverter. Engineers pumped a brine preflush containing a multifunctional surfactant to improve the post-treatment cleanup. This fluid was pumped during the injection test and was followed by a spacer before the main treatment. All the fracturing fluids were tested with the formation oil to ensure that there would be no problems with emulsion or sludge. The treatment was successfully pumped to completion.

The acid was recovered within a day of the well being opened for flowback. This acid fracturing treatment improved well performance and reduced pressure drawdown (to eliminate asphaltene deposition) as predicted in the prejob planning and test phase. Detailed production analysis and stress evaluation helped the team to quantify the probable increase in production that could be achieved. This prediction was confirmed in a production test, where the post-treatment oil rate of approximately 860 m3/d was almost double what it had been under the same operating conditions before stimulation—a–approximately 460 m3/d.

Diversion

Diversion is a technique used in injection treatments, such as matrix stimulation, to ensure uniform distribution of the treatment fluid across the treatment interval. Injected fluids tend to follow the path of least resistance, and this may lead to inadequate treatment of the least permeable areas within the stimulation interval.

Using diversion methods, engineers can focus treatment on the areas that require more stimulation. To be effective, the diversion effect should be temporary to enable the full productivity of the well to be restored when the treatment is complete. There are two main categories of diversion: mechanical and chemical.

Mechanical methods

Mechanical diversion techniques, such as ball sealers, packers, and straddle-packer assemblies, are used to divert reservoir treatments to the target zone. Ball sealers and solid-particle diverting agents incorporated into the treatment fluid form a temporary plug in the perforations accepting the most fluid flow, thereby diverting the remaining treatment fluid to the less permeable zones (Fig. 4a). Packers and straddle-packer assemblies function by performing several short treatments over a longer interval to help ensure even treatment over the entire zone (Fig. 4b).

Though widely used, mechanical diversion methods may not always be feasible or recommended. They are often ineffective for stimulation projects in long horizontal or extended-reach wells.

![Figure 3: To hydraulically fracture carbonate rocks, the workover team pumps acid to fracture the formation and to create a nonuniform etched pattern on the fracture surfaces.](image1)

![Figure 4: Ball sealers and solid-particle diverting agents create a temporary plug in the perforations that are accepting the most fluid flow.](image2)
Chemical methods

Conventional chemical diversion methods include nitrogen foam, bridging agents such as benzoic acid flakers, and crosslinked polymer gels. These create a temporary plug in high-permeability carbonate zones so that the stimulation fluids are diverted into the low-permeability zones that require more treatment.

Polymer-based gels are a well-established chemical diversion technique. These systems use reversible, pH-triggered crosslinker additives to alter the viscosity of the fluid during the acid treatment. SDA* Self-Diverting Acid is a polymer system mixed with HCl. When combined with fresh acid, the SDA fluid has a low viscosity to facilitate pumping. However, once this fluid enters a carbonate zone and the acid becomes spent, the polymer crosslinks and the fluid viscosity increases. The higher gel viscosity restricts the flow of fresh acid through the wormholes, and diverts it into the zones with lower permeabilities and, eventually, to all the zones requiring treatment (Fig. 5).

Modern chemical diversion methods can be very effective, but may create problems if incorrectly managed. In some wells, for example, temporary plugs may become permanent, which damages the formation and reduces production from the zone that was supposed to be stimulated.

A different direction for diversion

The potential risks of production damage when using polymer-based stimulation fluids prompted industry researchers to explore alternatives. Research led to the launch of ClearFRAC polymer-free fracturing fluid, which is based on viscoelastic surfactant (VES) technology, and a high-temperature version of the system that can be used at temperatures to 135 degC. VES surfactant fluids are polymer-free, so they do not damage the formation. Their enhanced, drag-reducing properties and significantly lower friction pressure enable the stimulation team to reduce the pumping requirements and treat deeper zones. Schlumberger has developed a range of VES fluids for various applications. These include VDA diverting fluid, ClearFRAC hydraulic fracturing fluid, and ClearPAC* gravel packing fluid.

The VDA system is a self-diverting, polymer-free acidizing product that increases zonal coverage in carbonate reservoirs without residual damage. Unique chemicals reduce the fluid loss. The system enables operators to optimize the removal of reservoir drill-in fluid deposits and selectively plug zones with high water saturation.

VDA fluid prevents the damage caused by solids and polymers during matrix treatments. It can be used alone or with other treating acids for total zonal coverage in carbonate reservoirs. The high-viscosity barrier is broken down by production or dilution with formation fluids. VDA operations can be conducted at low pressures, and recovery and well cleanup are simple.

Across the Middle East and Asia, VDA systems have been used in matrix stimulation and diversion applications in vertical, horizontal, and extended-reach gas and oil producers and water injectors and for acid fracturing in oil and gas producers and water injectors. The VDA system is a self-diverting, polymer-free acidizing product that increases zonal coverage in carbonate reservoirs without residual damage.

Success in Saudi Arabia

In Saudi Arabia, there has been a significant change in carbonate reservoir stimulation techniques, with a shift away from polymer-based stimulation fluids toward nondamaging VDA systems. Saudi Aramco has used VES fluids for a range of stimulation applications, including matrix acidizing and diversion in production and water-injection wells, and acid fracturing in high-pressure, high-temperature gas wells and water-injection wells.

Before the emergence of VES technology, matrix stimulation of carbonate reservoirs in Saudi Arabia relied on the use of crosslinked, gelled, and emulsified acid systems. Unfortunately, in sour environments, i.e., those containing hydrogen sulfide, iron-control agents are ineffective against the precipitation of iron sulfides. In an effort to improve fluid diversion, reduce damage, and boost production, Saudi Aramco decided to test a VDA system for matrix stimulation of wells under challenging conditions.

Some of the candidates chosen for VDA matrix stimulation were long, horizontal wells with openhole sections ranging from 460 to 1,830 m and temperatures approaching 120 degC. In many of the wells, there were serious concerns about a water zone immediately below the targeted horizontal section. This made effective diversion a vital factor in reducing or eliminating water production.

In the extended-reach wells, coiled tubing (CT) was used to deliver the treatment to the reservoir. The treatment comprised a VDA surfactant in 20–28% HCl and a corrosion inhibitor.

In those wells where the CT could not reach total depth, the VDA treatment was bullheaded from the maximum depth that the CT attained. The pumping rates were sufficient to achieve stimulation and diversion of the entire horizontal section. Most of the wells used VDA fluid energized with 30% nitrogen. Treatment rates down the CT were between 0.15 and 0.24 m³/min. The use of nitrogen accelerated cleanup, minimized acid leakoff, provided better coverage, and reduced acid volume requirements.

Saudi Aramco and Schlumberger engineers found that the production rates of the 5 wells after stimulation with VDA fluid were much greater than the average production from 11 offset wells that had been stimulated without the VDA system (Fig. 6). Water cut in the VDA-treated wells was much lower than in wells treated with other systems. This was because the high-viscosity gel in the water zones remained intact, whereas the gel formed in the hydrocarbon zones had broken and enabled the acid to migrate further into the matrix. This led to more effective stimulation of the hydrocarbon-bearing zones and higher rates of oil or gas production.

Avoiding damage to the well

When operators place acid or other treatment chemicals in their wells, they have to be sure that any reactions occurring will be beneficial. If a stimulation job is performed incorrectly, there are potential risks to the oil production, to the well, and to the surface equipment. To optimize the performance of oil and gas wells, the stimulation team should avoid damaging or altering the formation, prevent or treat the development of emulsions or sludges, remove insoluble reaction products, and prevent acid damage to the well and the surface equipment.

Water-bearing zones

One of the fundamental requirements for any stimulation program is that the increase in conductivity is restricted to the hydrocarbon zone. Acid or fracture stimulation of water-bearing layers adjacent to the reservoir would lead to a sharp rise in water production with the associated issues of fluid handling, separation, and disposal. In extreme cases, stimulation of the water zone could end the economic life of the well.

Figure 5: When combined with fresh acid, the SDA fluid has a low viscosity to facilitate pumping. However, once this fluid enters a carbonate zone and the acid spends, the polymer crosslinks and the fluid’s viscosity increases.

Figure 6: Saudi Aramco and Schlumberger engineers found that the post-stimulation production rates of the five wells stimulated with VDA fluid were much greater than the average production rates from 11 offset wells that had been stimulated without the VDA system.

[Numbers and values are not accurately transcribed due to the nature of the image.]

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Emulsions and sludges

During fracturing and matrix acidizing, the acid may come into direct contact with produced crude oil or well fluids. This may result in the formation of emulsions or sludges. Emulsions can be viscous and may block the treated formation and reduce oil production. Reservoir engineers can add anti-emulsifying and anti-foaming agents to prevent these emulsions forming and demulsifiers to break emulsions once they have formed.

Insoluble reaction products

When operators anticipate that a formation will contain large amounts of acid-insoluble silts or other fines that could be released during acidizing, they should treat the acid with a silt-suspending agent. If left untreated, these solids can cause severe plugging of pore throats during flow back. By keeping these solids in suspension, the operators can produce them out of the formation and avoid damaging the well's performance.

Most silt-suspending agents are also foaming agents that add to the dispersibility of insoluble materials and aid the speed of cleanup, particularly in gas wells and when used with nitrogen or carbon dioxide.

The MSR mud and silt remover is an acid solution containing a clay dispersing-suspending agent and an iron chelating agent. This combination of additives provides good dispersion of drilling muds and formation silt, and unusually effective suspension properties.

The MSR service is designed to remove drilling mud damage in both carbonate and sandstone formations. It can restore fracture conductivity in workover operations and reopen clogged perforations. The service also removes damage from the critical matrix during matrix acidizing and restores the natural permeability in fissured or fractured reservoirs after mud losses. The value of combining the MSR service with SDA technology was underlined in a comparative test of treatments for an injection well (Fig. 7).

Preventing acid damage to well and surface equipment

Corrosion inhibitors prevent acid damage to equipment both at the surface and in the well. Typically organic compounds that adsorb onto metal surfaces, inhibitors are chosen on the basis of exposure time and temperature. The initial cost of corrosion inhibitors may seem very high—they are the single most expensive component of the materials used—but the cost of damage to pumping equipment and tubulars if they were not to be used would be even higher.

Egypt: VDA treatment for a dolomite reservoir in Egypt

More than 70 VDA treatment projects have been conducted across Egypt to date. A specially formulated MSR-dol acid was used to stimulate the Alamein dolomite formation in a discovery well, Well 1, in Egypt’s Western Desert.

Well 1 did not flow following perforation and CT lifting with nitrogen. The operator decided to perform an acid treatment. ELANPlus® advanced multimodal log and core analyses had indicated the presence of pyrite within the pay zone; consequently, the matrix acidizing treatment had to be designed to avoid precipitation of iron compounds.

After the treatment program, Well 1 produced oil at around 380 m³/d. Encouraged by this, the operator decided to apply a similar stimulation procedure in two more wells that were only producing a few hundred cubic meters of oil per day from the Alamein dolomite. The treatments in wells 2 and 3 were enhanced by the addition of VDA polymer-free fluid.

In Well 2, where the MSR-dol acid formula was diverted with polymer-free VDA fluid, oil production rose to around 500 m³/d. The results from Well 3 were even more impressive—oil production increased to 1,100 m³/d.

The overall result for this three-well campaign was an increase in the field’s oil productivity of 1,300 m³/d (Fig. 8).

Current challenges

In many countries across the Middle East and Asia, horizontal wells have become the preferred approach for developing carbonate reservoirs. The long sections in some of these wells present major problems for operators who want to stimulate their wells.

Tailored treatments for long horizontal wells

The efficient placement of conventional acids is critical, especially in long horizontal sections. Owing to their fast reaction rates, acids have to be placed using CT or foam, gel, or other diversion methods. Significant care has to be taken over treatment design when using diversion methods, and there may be a problem with gel residues.

Applying HCl in extremely long horizontal producing intervals to uniformly remove drilling damage has been identified by several operators as being very challenging—the result is usually disappointing well productivity.

Long, openhole horizontal wells provide an efficient way to develop complex carbonate reservoirs, but there are challenges in attempting to stimulate these wells. Schlumberger has proposed a new method to optimize the stimulation and boost the production in these wells.
Mechanical isolation and individual treatments

Carbonate reservoirs can be extremely variable, and therefore the reservoir zones within a long horizontal well may have very different petrophysical characteristics.

Each of the zones would respond in a different way to a standard stimulation treatment. The most effective stimulation program would treat each zone in the most appropriate way. Matching the needs of the interval to the most appropriate stimulation technique would see permeable intervals treated with a scheme of matrix acidizing, while tight zones in the same well could be optimized with acid fracturing (Fig. 9).

Once all the zones had been optimized in this way, the whole well could be opened up for production. This pinpoint stimulation method has been used in North America and has clear applications in the Middle East and Asia.

Notches for even distribution of stimulation fluids

As operating companies continue to produce more advanced and effective strategies for field development, the service companies must respond by generating technology to meet the new completion methods.

CT is a well-established method for delivering stimulation fluids in horizontal wells. However, in very long openhole wells, the CT stimulation method may not be feasible. For example, in Saudi Arabia where some of the world’s longest horizontal wells are being drilled, CT systems cannot reach total depth for the well.

In the absence of a CT-based delivery mechanism, some operators have no option but to bullhead the acid by pumping it from surface at a high rate. Unfortunately, this approach tends to concentrate the acid in the heel or toe section of the well and leave the remainder of the hole untreated (Fig. 10a).

When Saudi Aramco raised this issue at a workshop, a RapidResponse* project was initiated to address the problem. Engineers devised a tool that creates notches in the formation within the borehole. The tool pumps an abrasive fluid through a special nozzle to create a series of long, wide notches that penetrate approximately 35 cm into the formation. Acid treatments will tend to flow into these notches, and this will, if the notches are distributed along the length of the borehole, spread the effects of the treatment fluid along the well (Fig. 10b). This technique has been extensively tested, and it is hoped that field trials will be conducted soon.

Figure 9: The stimulation techniques used must be matched to the needs of the various intervals in long horizontal wells for optimum production.

Figure 10: Bullheading acid into a horizontal well tends to concentrate the acid in the heel or toe section of the well and leave the remainder of the hole untreated (a). Notches created along the length of the borehole wall tend to fill with acid, which distributes the effects of the treatment along the well (b).
**Solid acid system to increase fracture length**

The effectiveness of a hydraulic fracturing program in tight carbonate formations depends to a large extent on the length of the fracture that is created. Pumping HCl into the formation at pressures sufficient to fracture rock typically creates fracture lengths in the range 15 to 30 m. In a tight carbonate reservoir, engineers would like to increase the average length of the fractures created to 60 or even 90 m.

A range of techniques to increase fracture length has been examined. One of these involves a new acid system that aims to combine the effectiveness of mechanical fracturing with the stimulation benefits of an acid fracture treatment. The acid is pumped as a solid, and only starts to react once it has found its way into the fracture (Fig. 11).

**The future**

The high degree of heterogeneity encountered in carbonate reservoirs makes them very difficult to manage. As more of the world's large carbonate oil reservoirs mature, operators are turning to stimulation methods to optimize water or gas injection and extend the productive life of the field.

Efforts to enhance the stimulation of carbonate reservoirs will depend to a large extent on what is achieved in other technical areas. Advances across a range of disciplines, from petrophysical analysis to geophysical imaging, will help asset teams to manage their carbonate reservoirs more effectively. The key to improving oil and gas production from carbonate fields is a clear understanding of the reservoir—its structure, lithology, and petrology—combined with an effective array of stimulation technologies.