The Right Treatment for the Right Reservoir

Flow rates in most wells increase significantly after hydraulic fracture treatments. In some completion configurations—notably multizone and long-reach, high-angle wells—capital and operating expenses often negate economic gains from improved ultimate recovery or accelerated production. This drawback is being addressed today by combining more efficient, multizone fracturing tools and services with real-time monitoring capabilities.

Among the strategies used today to produce a larger proportion of original reserves in place are high-angle, extended-reach wells, multizone wells and recompletions aimed at capturing previously uneconomic or stranded oil and gas deposits. Recent improvements in geosteering technology allow high-angle wells to be drilled to increasingly greater distances, while preventing the well path from straying beyond the upper and lower boundaries of the pay zone. The result is an ability to greatly increase wellbore contact with the formation and so significantly improve drainage.

Increased formation contact is essential to the success of many of these long lateral wells. This is because most of the formations that readily give up hydrocarbons were discovered and developed years ago. That leaves today’s operators the task of producing oil and gas from unconventional or low-permeability sources such as shale or the outer reaches of mature fields.

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where reservoir quality may be low. While extended-reach wells play a significant role in improving reservoir contact, exposure to the formation can be further increased with hydraulic fractures.

In vertical wells, hydraulic fracturing can improve reservoir contact several hundredfold. In horizontal wells, the improvement is exponential (previous page). While the results from fracturing high-angle, long-reach wells have been encouraging, many of these treatments often fail to deliver expected economic or production gains. This outcome is a function of the original completion methods: to maximize wellbore-formation contact, these wells are traditionally completed open hole or with slotted or preperforated liners across the production zone.

In an openhole completion, effective stimulation along the horizontal wellbore is almost impossible using traditional bullheading methods, since it is difficult to place fracture fluids and acids precisely within the formation. Typically, with the use of standard methods, only the upper sections, or heel, of the wellbore are treated, with little fluid ever reaching the middle or lower intervals (left).

When operators choose to complete horizontal wells with cemented liners, individual zones can be more readily isolated and treated. However, as with any multizone treatment, the costs of multiple, time-consuming trips per zone often outweigh the value of the resulting increased production.

Despite these hurdles, and because hydraulic fracturing does consistently result in increased production, demand continues to grow for the practice in all types of wells. In an effort to attain better results—from both a cost and production standpoint—service companies are delivering

This article describes fracturing and completion systems that allow operators to overcome the economic and technological barriers to hydraulic fracturing in certain, increasingly prevalent well types. Examples from North America, Africa, Saudi Arabia and Kuwait demonstrate how these innovative approaches have resulted in efficient, economically viable fracturing and acidizing treatments in reservoirs once deemed poor candidates for such procedures. We will also examine recent innovations that allow operators to model and then monitor and refine their fracture treatments in real time.

**An Eye on Growth**

As in many oil and gas operations, integration with real-time monitoring has greatly enhanced the effectiveness of hydraulic fracturing. In the past, downhole pressures were derived from measurements taken at the surface and extrapolated to bottomhole conditions. Today, these measurements are acquired directly at the sandface in real time using coiled tubing with an installed fiber-optic line (left). The measurements are obtained successfully despite the extremely harsh downhole environment created during hydraulic fracturing operations.

Fiber-optic-equipped coiled tubing (FOCT) systems feature a downhole sensor package that sends real-time downhole depth, temperature and pressure data to the surface. In addition, the optical fiber can obtain distributed temperature readings at 3-ft [1-m] intervals. Data are transmitted from the toolstring through the fiber-optic line to an electronics package that converts the fiber-optic signal to a wireless signal. This, in turn, allows transmission of the data to a control cab where the information can be viewed remotely through a command-and-acquisition software program.

Operators also can gain considerable value from accurate definition of the fracture system geometry as it is being created. Equipped with such knowledge, engineers can design successive fracturing operations within a field to avoid undesired results. In the past, fracture mapping was performed through postfracture analysis measurements such as temperature logs, radioactive tracers and tiltmeter surveys. However, these tools have shortcomings. Temperature logs or radioactive tracers can provide only near-wellbore fracture height and width. And while information about the azimuth and symmetry of the fracture may be gained from surface and downhole tiltmeter mapping, these methods do not accurately assess the fracture’s height, length and width.

More recently, service companies have developed the ability to describe fracture geometry using borehole seismic methods. The StimMAP hydraulic fracture stimulation diagnostics service uses multicomponent receivers in an offset well to record the microseismic activity caused by the creation of hydraulic fractures in the treated well. To create the velocity model needed for microseismic data analysis and processing, a seismically calibrated velocity model survey is performed in a nearby monitoring wellbore. This borehole seismic survey is performed before fracturing.

The map of these microseismic events allows engineers to better understand the development of induced fractures in time and space. Mapping also provides valuable geological insight into the treated formation.

Engineers at the monitoring or treatment well can communicate with other locations using the InterACT connectivity, collaboration, and information system. Remote office locations can be included in the communications loop for instant processing and interpretation of the data.

The StimMAP system uses real-time data to locate microseismic events automatically in 3D space (next page). Comparing the fracture mapped by the StimMAP service with a fracturing design and evaluation software model provides useful information for improving future treatments. The lessons learned enable operators to optimize well-stimulation costs and gain insight for new in-field drilling opportunities.

The StimMAP system was recently applied in a multizone fracturing operation in an east Texas horizontal well. During stimulation aimed at the third zone, engineers observed unintended microseismic activity in the region of what was to be a fifth zone. Following unsuccessful attempts to redirect the fracture, the company halted operations.

Engineers coupled StimMAP Live services—a specific application of the StimMAP system that permits engineers to monitor and, if necessary, alter fracture treatments as they are being performed—with pumping data to diagnose the mechanical problems that were causing the fracture to veer from its planned direction. The job was then resumed and three more zones treated. Without the insight afforded engineers by real-time feedback, six fracture treatments would have been pumped into the same zone. Instead, the operator was able to salvage three of

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*Real-time data. Fiber-optic cable inside coiled tubing delivers a distributed temperature profile throughout the wellbore. Temperature variations provide information that shows where fracture fluids are entering the reservoir. In relatively low-rate applications, ACTive in-well live performance measurements can be made as the fracture treatment is pumped directly down the coiled tubing. During what are termed high-rate jobs—more than 450,000 lbm [204,117 kg] of sand pumped at 10 bbl/min [1.6 m³/min]—the fiber bundle, known as the tether, begins to move forward and buckle, causing it to fail. For those jobs, the system monitors conditions as the sand is pumped down the CT-casing annulus. The sensor package shown here includes a battery (white), a circuit board with temperature sensor (green) and pressure transducers (light blue).*
the remaining five treatments while avoiding the weeks of diagnostic workover costs that otherwise would have been necessary.

Making Multizone Pay

In times of high commodity prices, operators are naturally anxious to make the most of their assets by producing as much hydrocarbon as is economically feasible. To do so, they often complete numerous zones with a single wellbore or expose long intervals of formation through horizontal or high-angle drilling. As discussed above, results from traditional approaches to fracturing these wells may fall short of operator expectations for economic or technological reasons.

Multizone fracturing, as opposed to traditional methods that include multiple trips per zone, targets both economic and technological concerns. Through efficient practices and new techniques, these services may reduce weeks of rig costs to a few days or even entirely eliminate the need for a workover or drilling rig. Multizone fracturing practices also are able to deliver more effective treatments that optimize formation contact because they can more accurately place treatments without adding risk.

Service companies have customized systems to address the varied types of multizone wells operators seek to treat. Schlumberger has created a four-category package of hydraulic fracturing services based on well type and operator philosophy. Called Contact staged fracturing and completion services, the categories include the following:

- conventional systems that require separate trips into the well to perforate a zone in one trip, then stimulate and isolate it in a second trip, repeating that process for each zone
- intervention systems that perforate, fracture-stimulate and isolate numerous zones in a single trip
- permanent systems that fracture-stimulate and isolate multiple zones in one pumping operation using assemblies that remain in the well as part of the completion
- dynamic systems that use a degradable diverting material to successively plug and isolate treated perforations and divert stimulations to other intervals in a continuous operation.

Conventional fracturing—pumping the fracture fluid and proppant or acid down the casing or fracture workstring—is most effective for massive hydraulic fracture treatments in which hundreds of thousands of pounds of sand are pumped downhole at high rates. In cased holes, the reservoir is accessed through perforations created by wireline, abrasive jetting or shifting sleeves in the workstring.


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the hole to the next zone. Once the first treatment is complete, a sand plug may be set for isolation and the next zone perforated (middle right). This

High-pressure perforating and treatment. The AbrasiFRAC service uses a high-performance abrasive jetting tool to operate continuously under harsh
tubulars and surrounding cement, then penetrates deep into the formation (far left). The entire well may be fracture-stimulated by pumping treatment fluid down the casing or fracturing string and into the formation in a practice known as bullheading. As in cemented completions, once a completion string is in place, diversion may be attempted by using limited entry, ball sealers or traditional chemical diversion.

In wells with openhole completions and unconsolidated formations, conventional fracturing may include deploying a completion string—typically a slotted or perforated liner—to ensure wellbore integrity. The entire well may be fracture-stimulated by pumping treatment fluid down the casing or fracturing string and into the formation in a practice known as bullheading. As in cemented completions, once a completion string is in place, diversion may be attempted by using limited entry, ball sealers or traditional chemical diversion.

Staging an Intervention

The intervention category of hydraulic fracturing comprises three services: AbrasiFRAC abrasive perforating and fracturing service, PerfFRAC selective perforating, fracturing, and stage isolation with ball sealers, and CoilFRAC stimulation through coiled tubing.

The AbrasiFRAC technique enables accurate placement of fracturing treatments down the casing or the workstring-casing annulus. It also reduces near-wellbore pressure drop from the wellbore to the reservoir, which decreases the frequency of near-wellbore screenouts when proppant stops entering the formation and builds up inside the casing. The technique is particularly well-suited to treating formations with high fracture-initiation pressure and areas in which precise placement is critical to the success of the stimulation.

The system is based on a well-established oil industry technique for cutting casing and tubulars downhole: a slurry containing abrasive solids is pumped at high differential pressures through an ABRASIJET hydraulic pipe-cutting and perforating service gun conveyed on a workstring. The resulting high-velocity fluid stream cuts through tubulars and surrounding cement, then penetrates deep into the formation (below).

The cutting tool is used to perforate the casing and formation. The abrasive material is usually 20/40- or 100-mesh fracturing sand, which is compatible with the specially engineered jet guns. Sand plugs may be used to provide zonal isolation between the fracturing treatment zones. The jet guns, which are available in various size and phase configurations, also can be used with retrievable or millable bridge plugs for isolation.

One example of the use of the AbrasiFRAC service was in the highly laminated Hosston sands of the Sligo field in northern Louisiana, USA. The Hosston sands contain many thin, gas-bearing sands alternating with water-bearing sands, with varying levels of depletion. Typically, wells in this area are completed with multistage stimulation

When multiple intervals are open within a single zone, diverting fluid from one to another in order to treat each of them may be accomplished through such practices as limited entry, ball sealers, chemical diversion, composite bridge plugs and sand plugs. Limited entry is created by placing fewer perforations across certain sections to increase friction at the open perforations. This diverts the fluids from a zone that, because of high permeability or other factors, may have absorbed the bulk of the treatment at the expense of other intervals or zones (left).

Composite bridge plugs are isolation barriers set in the casing above the treated zone and drilled out later, usually in a separate workstring drilling operation. This incurs a time penalty and adds operational risk. Additionally, the time between treating the lowest formation and flowing it back can sometimes be measured in weeks; in some cases, that may be enough time for the fluids to leave residue in pore spaces, causing significant damage to the formation.

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treatments using energized fracturing fluids and bridge plugs for isolation between zones.

In an effort to improve cost and time efficiencies, EOG Resources field-tested the AbrasiFRAC service. The technology allowed the operator to stimulate multiple intervals within a well in a single field operation and to more effectively and efficiently stimulate the individual sands. Treatments varied from four to nine stages using CO₂-energized fracturing fluids. The result was to cut water production by 85% while doubling gas production.

Another approach to efficiency is to treat zones immediately after perforation without first pulling the guns out of the hole. This step alone saves one running and one pulling trip per zone. The PerfFRAC service is designed to perform high-rate treatments down the casing while the perforating gun assembly remains in the wellbore. First, the guns for each zone are run in the hole and the first zone is perforated. Then, as the first zone is being treated, the unfired guns are moved up the borehole and positioned to shoot the holes for the second zone.

At the end of the first zone’s treatment, ball sealers in a fiber diverting fluid are pumped into the well. A rise in pump pressure indicates that the ball sealers and slurry have sealed against the perforations of the treated zones. At that point, the guns for the second zone are fired, and the second treatment, again tailed in with ball sealers and fiber-infused diverting fluid, is pumped. This process is repeated for multiple zones. To date, as many as eight sets of guns have been run and six separate zones treated in a single intervention (below).

The PerfFRAC service often results in better production rates than other, less efficient treatments because it allows precise targeting of treatments, ensuring that no zones are underserved. The method also allows the well to be flowed back immediately and so avoids the risks associated with milling out composite bridge plugs and leaving potentially damaging fluids in the formation for an extended time period.

Goodrich Petroleum was seeking to bring just such efficiencies to its Cotton Valley field in east Texas. Engineers had been treating these wells using traditional practices: perforate the first zone, fracture-stimulate it, flow the well to clean it up, and finally set a composite bridge plug for isolation.

This process was repeated for each zone of interest. Once the last zone was treated, a coiled tubing unit was brought on location to drill out the composite bridge plugs. This sequence cost the company US $250,000 and took five days to complete. Goodrich opted to use the PerfFRAC service to complete 23 of its wells and in doing so reduced the five-day operation to one day, while eliminating the need for bridge plugs and coiled tubing milling.

But the break with past practices paid a more important dividend than just lower operating costs and shorter time to production. In the first

Multistage versus traditional fracturing practices. In the Cotton Valley field of Texas, Goodrich Petroleum used multistage fracturing to reduce treatment time (blue) from five days to one and costs (green) from US $255,000 to US $155,000 per well (left). In a 23-well program in the same field, the operator produced 25 MMcf more gas compared with what would be expected following traditional treatment methods that often sacrifice treatment efficiency to meet economic goals (right, horizontal scale not linear).

Workstring-conveyed selectivity. By combining a workstring with selective fracturing technology, operators can treat multiple zones in a single trip. In new wells, each zone is perforated conventionally in one wellsite visit. Coiled tubing or jointed pipe is then deployed into the wellbore with an openhole packer bottomhole assembly (right). The bottom zone is isolated by packers above and below the target formation, and the fracture stimulation is pumped through the workstring (left). Residual proppant is reverse-circulated out of the wellbore and the packer is moved to the next zone, where the process is repeated. The insets represent real-time monitoring of each treatment.
efficiencies gained from other practices such as three-sand stages. The trick is to do so without sacrificing the cost savings per well. Gas-to-market time was reduced by four days per well, netting the operator an additional 25 MMcf [708,000 m³] of gas—a 22% increase over wells completed using conventional methods. This gain allowed the operator to increase its estimated ultimate recovery per well by 10% (previous page, top).

In all, using the PerfFRAC system saved Goodrich Petroleum 92 completion days on 23 wells. Additionally, reduction in equipment on location saved another 25% on total completion costs per well. Gas-to-market time was reduced by four days per well, netting the operator an additional 6 MMcf [169,900 m³] of initial gas.

Diversionary Tactics

With the adoption of ball sealers and limited entry, treated zones can be isolated and the fracture treatment diverted to untreated zones. While these isolation and diversion techniques have the advantage of significantly reducing the number of trips and the costs required to fracture wells with multiple zones, because of differences in fracture gradients between sands within a well, these methods leave some zones ineffectively treated.

One solution to this shortcoming is to isolate and stimulate each zone individually with a treatment designed specifically for its parameters. The trick is to do so without sacrificing the efficiencies gained from other practices such as limited entry and ball sealing. To that end, engineers have developed systems that isolate zones between sealing elements by using openhole packers that may be set, unset and reset numerous times.

The CoilFRAC coiled tubing stimulation service uses an openhole packer assembly deployed on a workstring across the bottom zone after the entire well has been perforated conventionally (previous page, bottom). The stimulation fluid is then pumped down the tubing string, through the treatment sub of the packer tool and into the isolated interval. Residual proppant is then reverse-circulated out and the packer moved to the next zone. This method not only permits stimulation of all zones in a single intervention but, like other Contact services, increases treatment efficacy by allowing the operator to customize each treatment to suit each zone.

In older wells, this type of service is especially suited for accessing bypassed reserves and for refracturing previously completed zones.¹¹ In this application, the goal is not only to minimize the cost of fracturing mature assets, but to do so while protecting downgraded casing from high treatment pressures and abrasive, proppant-laden fluids. Using a workstring as a conduit offers the added advantage of allowing the operator to treat targeted zones without first having to kill the well—a procedure from which older, pressure-depleted formations may not recover.

180 days of production, the 23 wells recovered an additional 25 MMcf [708,000 m³] of gas—a 22% increase over wells completed using conventional methods. This gain allowed the operator to increase its estimated ultimate recovery per well by 10% (previous page, top).

In another example, this time in southeastern Alberta, Canada, engineers were experiencing similar setbacks in their stimulation efforts in a shallow gas field. The wells in the area are usually completed in four zones, ranging from 820 to 1,480 ft [250 to 451 m] deep. The formations are composed of layered, silty sands that fracture easily.

Historically, operators in this area have used various fracturing techniques, including composite bridge-plug isolation. On a four-zone completion, such conventional practices require eight trips into the wellbore and an additional 16 days to complete the well with flowback required between each treatment.

The value of customizing discrete treatments to suit the needs of each interval in a multizone well was clearly demonstrated in a Rocky Mountain oil field of the USA. The field contains multiple vertical sand layers that are from 5 to 60 ft [1.5 to 18.3 m] thick and distributed from a depth of 2,000 ft to 5,000 ft [609 to 1,524 m]. The operator had been completing wells in this field primarily with limited entry, but had used bridge plugs when the distance between layers was significant. However, because of the varied fracture gradients exhibited in each sand layer, many zones were not being effectively stimulated. In addition, some marginal sand layers were left untreated for economic reasons.

In its search for an effective way to stimulate each zone without increasing completion costs, the field’s operator chose to use the CoilFRAC system. The decision paid off. For example, one well in the field had been producing 1.9 MMcf/d [53,800 m³/d] from one limited-entry fracture stimulation of multiple layers. With the packer assembly, bypassed layers were perforated and the entire well was restimulated. Eight fracture stimulations were performed in one day, and the stabilized production rate from the well was recorded at 5.3 MMcf/d [150,100 m³/d].

In addition to a more effective stimulation of each layer, the treatments took only one to two days, compared with the several weeks required to do the jobs using conventional techniques. In the four-well test, average production rates of the wells with the CoilFRAC system were more than twice those of standard completions (above left). As a consequence, recoverable reserves per well were increased by more than 75%.

The more efficient, commingled multizone stimulations that rely on limited entry or ball sealers for diversion gain time compared with traditional practices but, as discussed earlier, sacrifice production to do so. In addition, wells in the area are generally stimulated in groups to make the most efficient use of fracturing equipment.

The operator determined that, to optimize stimulation and production, each zone should be fractured individually at reduced pump rates. That decision made CT-conveyed fracturing treatments an obvious choice and resulted in reducing operation time to the point that crews were treating two wells per day (left). This was a critical advantage because for environmental and economical reasons, summer access is restricted to 10- to 14-day operational windows. In all, using the CoilFRAC service saved the company US $110,000 while increasing production by more than 190% in one field.

Permanent Solutions
Motivated by a desire to minimize the number of interventions or tools introduced into horizontal and high-angle wells, some operators prefer to treat zones using equipment that will become part of the permanent completion design. One way to do so is to complete the well using conventional casing with sliding sleeves. In openhole completions, such a system includes hydraulically operated openhole packers to create a seal against the wellbore wall.

In either cemented or openhole wells, each zone is treated through the sliding sleeves. The purposes of the cement and openhole packers are the same: to provide isolation between zones of different treating pressures and to ensure treatment along the entire length of the well.

Like other multizone services, permanent solutions also reduce risk by limiting trips in the hole to set and remove bridge plugs and increase treatment efficiency by allowing the operator to design each treatment for a specific zone. This strategy also increases the number of zones that can be treated because operators


13. Skin is a dimensionless factor calculated to determine the production efficiency of a well by comparing actual conditions with theoretical or ideal conditions. A positive skin value indicates some damage or influences that are impairing well productivity. These are the result of completion or drilling fluid residue left on or in the formation. A negative skin value indicates enhanced productivity, typically resulting from stimulation.
often address risk by reducing the number of plug pulling and running trips. This inevitably leads to limiting the number of zones that may be isolated and treated.

If engineers choose at some point to refracture a conventionally completed well in which all perforations are left open, they must do so through the workstring. In addition to the cost of the rig required to do that and the risk involved, fracturing through a workstring introduces added frictional forces that limit the flow rate during fracturing, so the optimal design cannot be accomplished.

StageFRAC and RapidSTIM multizone fracturing and completion services incorporate Packers Plus technology—openhole packers that are run on conventional casing to segment the reservoir with ball-activated sleeves placed between each set of openhole packers. The two systems are nearly identical except that the StageFRAC service treats the isolated zones through frac ports, and the RapidSTIM service does so through jets. Both frac ports and jets are located between the packers and behind ball-activated sliding sleeves (previous page, bottom). This mechanical diversion allows for precise fluid placement, complete zonal coverage and greater effective fracture conductivity.

Eni Congo turned to this solution when faced with a significant challenge in its offshore operations near the Republic of the Congo coast in West Africa. These aging fields still contain large quantities of reserves in low-permeability (10 mD), consolidated formations that are barely economic to produce using conventional stimulation methods. Formerly, stimulation consisted of matrix acidizing to eliminate or reach slightly negative skin.

Eni chose the StageFRAC service for three existing cased and perforated wells in the Kitina field where eight hydraulic, propped fractures were placed in three recompleted, cased-hole wells. These jobs were being pumped from a support barge to an offshore platform with limited deck space. As a result, only two zones could be pumped before the vessel had to be restocked.

The first well pumped was the KTM W6 ST (right). Two of the three zones treated down a stimulation liner were pumped without shutting down the pumps. Once the bottom interval had been treated, a ball was pumped, the zone was isolated, and the next zone was opened. The third zone was treated separately.
Three zones were also treated in the second of the three-well series. In the final well, it was determined that the lowest zone was too close to a water contact and this zone was left untreated. Stabilized production from the three wells increased 230% over their previous performance. Production prior to fracturing was around 590 bbl/d [94 m³/d]; after treatment, steady-state production was 1,950 bbl/d [310 m³/d] (left).

This sequential approach holds special promise for the offshore arena where completing a single fracture using conventional techniques can take a week and must be done from an offshore rig that costs several hundred thousand US dollars per day. By using openhole packers and sliding sleeves for isolation and fracturing the whole well in a single pump operation, each zone can receive extensive stimulation during a single mobilization of a stimulation vessel (left).

On land, it is the ability of sequential treatments to effectively treat an entire well containing numerous zones of differing quality that attracts operators to the technique. In Saudi Arabia, operator Saudi Aramco had completed a well with a 5,000-ft openhole, horizontal section through eight different zones of varying permeability. Because of its higher permeability, engineers expected most of the oil contribution to come from Zone 1. Because of the length and trajectory of the horizontal section, coiled tubing could not reach the lower sections and so the plan was to bullhead an acid treatment. However, because of its high permeability, Zone 1 at the heel of the well took all the acid, and the other seven zones were left untreated. As predicted and because it had received all the acid treatment, all production improvement came from Zone 1.

- **Offshore capacity.** The Schlumberger DeepSTIM group of stimulation vessels are specifically designed for fracturing and other fluid treatments. Their onsite quality control and mixing capacities (top), pump capacity (middle), and storage capacity (bottom), and their dynamic positioning capabilities render them self-sufficient. This eliminates deck and storage space concerns on platforms and the need for a costly offshore rig. Since these vessels are equipped to treat six or more zones sequentially, they can do in six hours what requires six weeks by conventional means—a significant savings of time in view of offshore rig day rates.
To remedy the problem, Saudi Aramco engineers chose to use the StageFRAC service for a staged acid fracturing of all the zones. Although Zone 1 had been treated, it was decided to not open it until the other seven were stimulated, cleaned up and tested. All zones were individually stimulated in one pumping operation and immediately flowed back. The seven previously untreated zones were tested and the results compared with those in an offset well that had been stimulated using coiled tubing and tested with all zones open. The well that received the StageFRAC treatment had twice the production of the offset well and triple its productivity index.

Saudi Aramco repeated this strategy in a field trial to hydraulically fracture long horizontal, openhole wells in a deep, high-pressure, high-temperature Khuff carbonate formation. These wells, company officials believed, were falling short of their production potential because of formation damage incurred during drilling operations.

Engineers were also interested in the feasibility of replacing unstimulated dual-lateral wells with hydraulically fractured single laterals. To that end it was imperative to employ a method that ensured stimulation of the entire length of the well—an impossible task in these long, complex completions using standard coiled tubing techniques.

The target of the field trial was the 3,835-ft [1,169-m] single lateral Well H-1 in the Khuff carbonate. Three fracturing stages were planned. The first frac port was opened ahead of the treatment by pressuring up on the workstring, and a step-rate injection test was performed to establish fracture parameters. The first fracture stage was then bullheaded down the tubing at a maximum rate of 94 bbl/min [15 m³/min] and a treating pressure of 11,700 psi [80.66 MPa]. A total of 16,700 galUS [63.2 m³] of treatment fluids, including acid and pad, were pumped.

A 2.5-in. ball was dropped, the second frac port was opened, and the second treatment by pressuring up on the workstring, and a step-rate injection test was performed to establish fracture parameters. The first fracture stage was then bullheaded down the tubing at a maximum rate of 94 bbl/min [15 m³/min] and a treating pressure of 11,700 psi [80.66 MPa]. A total of 16,700 galUS [63.2 m³] of treatment fluids, including acid and pad, were pumped.

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The well was cleaned up over a 54-hour flow period. Its performance was compared with that of Wells H-2 and H-3, two offset nonstimulated horizontal gas producers that showed similar results to the H-1 during their flowback periods. They were also picked because they were among the highest performers in the field when first put on production. Moreover, feet of net pay open to flow is six times higher in H-2 and three times higher in H-3 than in H-1. Additionally, both H-2 and H-3 have higher permeability and porosity than H-1.

Nevertheless, the performance comparison for the three during the initial flowback period shows that H-1 and H-2 were the highest producers with a similar rate of 65 MMcf/d [1.84 million m³/d]. However, Well H-2 achieved the same rate with a higher flowing wellhead pressure, indicating that it was a better performer than H-1. The stimulated Well H-1 produced at a higher rate than H-3 with similar flowing wellhead pressures.

Mixing It Up

The mechanical diversion and isolation afforded by this type of system can also be supplemented by chemical diversion. The Kuwait Oil Company (KOC) used a combination of openhole packers, frac ports and chemicals to revive a horizontal oil producer in the Sabriyah field where production had dropped to zero shortly after the well was completed in 2004 (above).14 KOC also chose the StageFRAC service because its mechanical isolation system remains active during the life of the well and could be used later to shut off certain zones that were expected to eventually experience water breakthrough. SXE SuperX concentrated hydrochloric acid (HCl) was used to achieve deep penetration and better etched fracture conductivity. This emulsion fluid is a viscous, highly retarded HCl system designed to overcome acid penetration problems when

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Stabilized crude oil within two hours. Stabilized immediately flowed back and cleaned up to 100% more costly drilling unit. The entire well was between layers using a workover rig instead of a well that had a 20 to 1 permeability contrast. Technologies allowed successful stimulation of a formation and allows movement of the fluids to viscous buildup serves as a barrier to reduce the viscosity in situ and becomes self-diverting. The acid reaction rate is retarded.

Before the acid is rendered ineffective. Deep, impossible for acid to penetrate, or wormhole, reacts so rapidly at high temperatures that it is ineffective. Deep, live-acid penetration can be achieved only if the acid reaction rate is retarded.

VDA Viscoelastic Diverting Acid was used to ensure full coverage across each zone. Upon spending, this acid rapidly develops high viscosity in situ and becomes self-diverting. The viscosity buildup serves as a barrier to reduce the development of dominating wormholes in the formation and allows movement of the fluids to stimulate other untreated zones. By doing so, it assures treatment throughout the target zone.

Six zones were stimulated within three hours, and the well was flowed back immediately after the treatment was complete. The combination of technologies allowed successful stimulation of a well that had a 20 to 1 permeability contrast between layers using a workover rig instead of a more costly drilling unit. The entire well was immediately flowed back and cleaned up to 100% crude oil within two hours. Stabilized measurement indicates sustained natural production of more than 10,000 bbl/d [1,590 m³/d] of oil—five times the field average and three times greater than the best well in the field.

Real-Time Control
Chemical diversion is also being used in hydraulic fracturing operations. Through the use of diverting fluids that degrade completely after the treatment, it is possible to stimulate numerous zones in a continuous operation without using diverting tools. Recent experience has shown that this method of diversion is particularly well-suited to fracture treatment of shale-gas formations. In almost every case, shale-gas wells must be hydraulically fractured before they can produce significant amounts of gas (above). Many of the new, deeper shale-gas wells are horizontal, and fracturing them can represent a considerable portion of completion costs.

Typically, because of the high cost of traditional multistage fracturing practices, horizontal shale-gas wells have been limited to two to four perforation clusters for every 500 ft [152 m] of lateral section. That means that a 2,000-ft lateral well, for example, would be treated in only four stages through 8 to 16 zones of entry, leaving about 90% of the wellbore untouched. The optimum approach to shale-gas fracturing would instead be 40 or more smaller stages, clustering the fractures as close together as possible.

When combined with real-time fracture monitoring, chemical diversion can be used to control fracture propagation as it occurs. With the Contact service dynamic category of treatment systems, engineers use the StimMAP service to track fracture or refracture creation as the job is being pumped and then compare the results with the expected outcome. Then, if the fracture is deviating from its desired course—for instance, threatening to enter a water zone—engineers can deploy the chemical diverting agent, DivertaMAX effective diversion service for multistage hydraulic fracturing, to redirect it. Slurries containing the DivertaMAX fluid are a blend of degradable materials that can temporarily block fractures, divert fluid flow and induce the creation of additional fractures in situ and at the wellbore.

This strategy is especially useful in shale-gas plays in which refracturing would seem to be an obvious solution to quickly falling production profiles. Perhaps the most active of these reservoirs, the Barnett Shale in the Fort Worth basin in north Texas, is a complex reservoir in which first-year average production decline is more than 50%. As a result, many of these wells—usually horizontal wells with multiple transverse fracture treatments placed across the reservoir—need to be refractured within five years of the initial completion. But economics dictate that this must be done more efficiently than is possible with traditional multistage, rig-based fracturing.

One operator was faced with this scenario on a Barnett Shale well that initially produced about 2.2 MMcf/d \[62,300 \text{ m}^3/\text{d}\]. In less than four years, production had fallen to less than 500 Mcf/d \[14,200 \text{ m}^3/\text{d}\]. Then microseismic monitoring of the original stimulation treatments revealed considerable opportunity to increase formation contact.

The operator employed the DivertaMAX service in concert with the StimMAP system as an alternative to the prohibitively costly traditional methods using bridge plugs and packers on a workstring for isolation. Based on measured posttreatment decline rates, the operator estimates the combination strategy will be paid out within six months of the stimulation. More importantly, recoverable reserves are expected to increase by 20\% over 20 years.

Another Barnett Shale well was completed in January 2005, and one year later had seen production fall from about 2 MMcf/d \[56,640 \text{ m}^3/\text{d}\] to half that amount. Microseismic data indicated a less than optimal stimulation had been performed during the third and fourth stages of the well’s original treatment. Production logs run in May 2006 and September 2007 also showed that a significant portion of the heel section of the reservoir was not producing, reducing the production rate by half again to 500 Mcf/d.

Company engineers decided to perform a single-stage fracture to stimulate the heel section of the wellbore. DivertaMAX diversion stages were pumped to allow for movement of the fracture entry point along the lateral. During treatment, diversion plugs were pumped based on feedback from StimMAP Live monitoring \(\text{(above)}\). After the treatment, production increased immediately from 500 to 1.2 MMcf/d \[34,000 \text{ m}^3/\text{d}\] and payout is expected in nine months. The treatment is also estimated to have the potential to increase recoverable reserves by 0.8 Bcf \[22 \text{ million m}^3\].

**Shale Gas: The Next Challenge**

Spurred by the low oil prices of the 1980s, the oil and gas industry rapidly developed new technology that enabled it to drill longer, more convoluted, directional and extended-reach wells. Initially, this effort was aimed at increasing wellbore contact through naturally fractured reservoirs that could flow on their own. Today, most of those opportunities have been, or are being, exploited, and operators must look increasingly to combining the benefits of extensive formation contact and hydraulic fracturing to attain economic production rates from their horizontal wells.

While that strategy is being applied to many types of low-permeability reservoirs, both new and mature, perhaps the most tempting target for its application today is in shale-gas reservoirs. Once ignored by operators seeking easier plays and quicker returns on investments, these tight-gas formations are currently boosting US natural gas reserves. In 2007, according to the US Energy Information Administration, 3.6 x 10^{12} \text{ m}^3 \[1.3 \times 10^{11} \text{ Mcf}\] of shale gas are technically recoverable from US reservoirs. The challenge is to release it.

In addition, because of the technology being developed and proved in the USA, shale-gas reservoirs may soon add significant reserves worldwide. While no commercial shale-gas enterprises are currently known outside of North America, worldwide reserves have been estimated at more than 16,000 Tcf \[453 \text{ trillion m}^3\] of gas.

The key to harvesting this potential is completing long, high-angle wells efficiently. Technologically, that means placing treatments optimally and accurately in each target zone along the entire length of wellbore, monitoring and altering the operation in real time and achieving all this at minimum cost and time. —RvF