Multistage Stimulation in Liquid-Rich Unconventional Formations

Production of liquids from shale formations, pioneered in North America, has grown exponentially in the past decade. The economics of these plays, however, remain sensitive to prices and demand, thus operators and service companies must continually develop more-efficient methods of recovering these once-overlooked hydrocarbons.

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During the past decade, oil companies have performed thousands of hydraulic stimulations on intervals along horizontal wellbores drilled through ultralow-permeability formations. Operators are using these techniques to exploit organic-rich shales, which were traditionally viewed only as source rock for conventional reservoirs.

These extremely tight sedimentary formations differ significantly from oil shales, which are sedimentary rocks containing kerogen—partially degraded organic material—that has not yet matured enough to generate hydrocarbons.¹ In contrast, as a result of the pressure and heat of the burial process, the kerogen in gas- and liquid-rich shales has matured sufficiently to generate significant amounts of gas and oil, which remain trapped within the shale.

Numerous liquid-rich shale formations exist in North America. Among these are the Bakken and the Eagle Ford formations. Unlike in other unconventional plays around the world, operators and service companies have years of experience working in these two extensive plays. The formations are familiar to petrophysicists and engineers and have been the proving grounds for much of the technology now used to exploit unconventional liquid-rich reservoirs.

Covering an area of 780,000 km² [300,000 mi²], the Bakken formation lies within the Williston basin of North Dakota, South Dakota and Montana in the US and in parts of Manitoba and Saskatchewan in Canada (below).² Operators first produced oil and gas from this formation in the early 1960s through conventional vertical wells. In the 1980s, production increased when...

⁴ Baihly et al, reference 2.
⁶ Martin et al, reference 5.
⁸ Baihly et al, reference 2.

The Bakken. The Bakken formation (pink) covers an area of more than 780,000 km² across the states of Montana and North Dakota in the US and parts of the Canadian provinces of Manitoba and Saskatchewan.
operators began drilling horizontal wells.\(^3\) When operators combined the complementary technologies of horizontal drilling and hydraulic stimulation to maximize the amount of formation exposed to the wellbore, North Dakota production from Bakken fields rose dramatically, from 16,000 m\(^3\) [600,000 bbl] per day in 2005 to 96,000 m\(^3\) [600,000 bbl] per day in 2012.\(^2\)

These increased production rates in North Dakota led geoscientists to consider using the same techniques to produce oil from source rock in other existing plays, including the Eagle Ford Shale, in Texas, USA, which is the source rock for the massive hydrocarbon accumulation that has produced from the Austin Chalk for 80 years. That trend overlies the Eagle Ford Shale across large swaths of south Texas (right).\(^2\) The Eagle Ford play, which stretches from central Texas southwest into Mexico, is 160 km [100 mi] long and averages 100 km [60 mi] wide.\(^6\)

In an effort to help operators optimally exploit unconventional plays, service companies have refined certain critical technologies. Today, operators are able to drill long horizontal wells and place them accurately within formation sweet spots. Production and completion engineers have also sought to improve methods for stimulating the numerous potentially productive intervals pierced by these wells (see “Stimulation Design for Unconventional Resources,” page 34).

Refinements to directional drilling assemblies such as the PowerDrive Archer rotary steerable system have led to more efficient drilling through higher build rates and improved rates of penetration. In addition, engineers have designed bits specifically for use in shale formations. The Spear steel bit from Smith Bits, a Schlumberger company, is designed to meet the demands unique to rotary steerable systems drilling in shale formations.\(^7\)

In ultralow-permeability formations, operators nearly always use multistage stimulation (MSS) techniques to access commercial volumes of oil, condensate and dry gas. These methods enable engineers to stimulate multiple intervals along horizontal sections. Typically, completion engineers isolate individual intervals and, either through perforating or by opening sliding sleeves, expose the zone to be treated. The well is then hydraulically stimulated. Engineers repeat this sequence, moving upward along the wellbore until all targeted zones have been stimulated. This article examines various MSS methods. Case histories from the US and China illustrate their use and advantages.

**Balls, Seats and Valves**

As the industry improved its ability to drill horizontally, wellbore lengths increased. So too did the number of intervals that had to be isolated and treated. In 2007, the average treatment number, or stage count, in Bakken wells was three. By the end of 2011, that number was nearly 30, and some wells had more than 40 stages in a single lateral.\(^3\)

While the economies of scale seemed to dictate treating as many intervals as possible per wellbore, operators sought to improve well economics further by reducing the time required to stimulate all the stages in a given well. Exploiting a liquid-rich shale play is drilling intensive, and despite the advantages of hydraulically treating longer wells, the drainage area of each wellbore in these tight formations is limited. With more than 200 rigs working in the Bakken at the end of 2011, there was great economic incentive to move the rigs off one well and on to the next as quickly as possible.

Traditionally, stimulating multiple zones in a conventional vertical well involved perforating the lowest zone, retrieving the perforating guns and pumping the treatment. The operator flowed the well back to drain extra proppant and carrying fluids and to force closure of the propped fracture. The completion engineer then set a bridge plug to isolate the interval from those above, pulled out of the hole to pick up perforating guns and repeated the process. Once all zones were treated, drillers milled out or retrieved the plugs and brought the well on line. Often, the well had to be completed with multiple strings of tubing or isolation valves to prevent crossflow between zones having different pressures. While this was a time-consuming process, it was not economically prohibitive in a vertical well with only two or three stages.

However, when dozens of intervals in each wellbore needed treatment, operators sought...
to reduce the time required between reaching total depth and initial production. In response, service companies developed more-efficient treatment methods that relied on external packers, balls and seats, or plugs, to isolate and treat intervals. They also developed valves that, in some circumstances, could be substituted for perforations.

Today, most horizontal wells are completed so that each interval can be isolated and perforated in one intervention—using pumpdown wireline or coiled tubing conveyance—and then treated. A final intervention may be required to mill out isolation plugs. Because the intervals are in one zone and equally pressured, the well is ready to produce.

Typically, service company completion specialists use plugs or ball-and-seat systems to isolate each stage. When the company opts for a plug, it is placed on wireline and pumped down the hole, or less commonly, it is run and set on coiled tubing. The assembly includes perforating guns. Once the plug is set above the topmost perforation cluster of the previous stage, the completion team pulls the guns into position. Each cluster of the next stage is then perforated, and the tools, along with the spent guns, are retrieved. Next, the team stimulates the open interval, and this “plug and perf” procedure is repeated (above). When all intervals have been treated, the driller mills out the plugs, and production from all intervals is commingled.

In other completion designs, a valve containing a ball seat and sliding sleeve is run into the hole as part of the completion. External packers isolate each interval. The ball seat is designed to capture a ball of a specific size that is pumped into the well. The diameters of the seats become successively larger from the bottom to the top of the completion. When the ball lands in the seat, continued pumping causes pressure to build against the ball and seat (below left). At a specified pressure, the ball-and-seat assembly moves downward, which opens a sleeve in the valve to expose the formation between the external packers. The interval is then treated. The next larger size ball is then run, isolating the treated zone. Completion specialists repeat this “ball drop” stimulation treatment sequence for all intervals beginning at the toe and moving toward the heel of the well. The method offers an advantage over the use of plugs because, as long as the ball seats do not represent a significant flow restriction, the balls may be flowed back to the surface, obviating the need for and risk of milling. Additionally, the operation is continuous, thus less time consuming.

For cemented completions, engineers may perform similar operations using specially designed valves run as part of the completion string. When the ball is pumped downhole, it lands and creates a seal in the seat of the deepest exposed valve, which results in a closed system. Pressuring the well causes the sliding sleeve to open, allowing the interval to be treated directly through the cement. As a result, the operator does not need to perforate the casing and cement first.

Despite the success of these systems, operators still seek hedges against narrow profit margins and unpredictable commodity prices that govern the economics of unconventional plays. In an effort to cushion profit margins, service companies are working with operators to refine MSS practices and tools and to shave costs and risks from well completion operations while simultaneously increasing production rates and ultimate recovery from these wells.

Making Good Ideas Better
In the mid-1960s, water depth of more than about 60 m [200 ft] was considered by the E&P industry to be a “very deep” working environment. But

operators were already contemplating the implications of servicing subsea wells completed with wellheads on the seafloor in water as deep as 3,650 m [12,000 ft]. To address the challenges of deep water, engineers developed several technologies, including pumpdown for interventions traditionally performed using slickline.

Pumpdown systems convey tools downhole using fluid pressure. When fluid is pumped against mandrels equipped with swab cups, tools move up or down the tubing. Because this system requires the fluid to circulate, designers created a crossover port that allowed circulation between the tubing and the annulus.

Today, completion engineers apply this method to push plugs and perforating guns attached to electric line to depth in horizontal wells. Service technicians set the plug above the shallowest perforation cluster of the previous fracture stage, detach the perforating guns from the plug assembly and move up the hole to create the next perforation cluster. After the guns have been fired, they are retrieved to the surface, and the interval stage is stimulated. The process is repeated for each stage. Once stimulation operations are complete, the driller must mill out each plug before putting the well on production.

In this form of MSS, the last step—milling—is often the most difficult and time-consuming portion of the operation in high-angle wells because weight on bit is limited. Engineers have developed plugs of varying design and material that are able to withstand stimulation pressures while at the same time are more easily ground into cuttings than are traditional cast-iron bridge plugs; these cuttings are small enough to be circulated out of the hole.

The aluminum Copperhead drillable and flow-through fracture plug and the DiamondBack composite fracture plug are examples of these new plugs (above right). The former is rated to 103.4 MPa [15,000 psi] and 205°C [400°F] and is designed to withstand multiple pressure and temperature cycles. The latter may be used when downhole conditions are less extreme and is rated for pressures up to 68.9 MPa [10,000 psi] and temperatures up to 177°C [350°F].

Both plugs are significantly easier to mill than are standard cast-iron plugs. Researchers have also developed a mill specifically for drilling out the Copperhead plug. The new mill reduces milling time and creates smaller cuttings. Because the DiamondBack plug is constructed of a composite material that is considerably softer than metal plugs, it is easily and quickly milled using standard mills.

In addition, both plugs are designed to prevent premature setting, which can be a problem with plugs that are landed and set on slips intended to wedge against the casing wall. If plugs of this design are conveyed downhole at excessive speeds, the slips may overtake the lower mandrel on the plug, causing them to expand against the casing wall and the tool to set. To help prevent this problem, both plugs use shear rings to hold the slips in place until at least half the set-down weight is applied to the assembly. This significantly reduces the chances that the plugs will be set prematurely even when they are run or pumped into the well at relatively high speeds.

When developing the pumpdown concept, designers incorporated a circulation path for fluids exiting the tubing and returning to the surface via the casing annulus. This process is not possible in cemented horizontal wells because until the well is perforated, the well is a closed system. Therefore, during plug and perforation operations using the pumpdown technique in a cemented horizontal wellbore, the first set of perforating guns—those at the toe of the well—must be conveyed on coiled tubing, wireline tractor or drillpipe. Service industry experts have tried several methods to avoid this costly step, including overdisplacing the cement to leave a flow path open through the casing shoe. For numerous reasons, including the inability to get a pressure test of the casing and cement, most operators deemed this “wet shoe” solution unacceptable.
Savings per well is critical for operators producing from low-permeability formations because these plays are typically exploited using many wells that produce at rates near their economic limit. To make such a strategy work requires each well to be drilled, completed and produced efficiently. The plug and perforate procedure with the first stage performed using the KickStart rupture disc valves helps operators reach that goal.COMPARE

**Ball and Seat**

In the past decade, operators have come to view openhole completions in horizontal wells as substantially more cost-efficient than cemented completions. These systems use hydraulically set or swellable packers to isolate each interval. Sliding sleeve valves, run as part of the completion tubulars between packers, are opened by hydraulic pressure applied to a seal created by a ball that is dropped from the surface to land in a mated seat. These seats increase in size from the smallest in the toe to the largest in the heel of the well, thus the smallest ball passes through each seat to the toe and the largest stops in the first seat near the heel (next page).
The industry has embraced these openhole systems because they may result in certain advantages over plug and perforate cased hole completions:

- less time-consuming and less expensive completion operations
- production from the open hole as well as the fractures
- a simpler connection between the wellbore and the fractures
- wellbore fractures that generate higher early production.

These systems also have potential disadvantages. Unlike cased wells that are stimulated through valves or perforations, openhole stimulations are confined only by packers, which may leave large sections of formation exposed between them. As a consequence, the operator has little control of the fracture location or number of fractures created in a stage. In addition, as the ball seats decrease in size with well depth, friction pressures increase, which may result in higher overall fracture initiation and extension pressures.

There may also be problems with the interaction between the ball and seat. When the ball lands and pressure is applied, the sleeve slides downward, exposing the annulus for treatment. The ball and seat then become the barrier isolating the lower intervals of the hole that have been previously treated. Both these actuator and seal functions are critical. If the ball fails to create a seal, the sliding sleeve may not move and the interval cannot be treated. At the same time, previously treated zones below the seat may be exposed a second time to stimulation fluids and pressure, which can damage production from that zone as well.

After all the intervals have been successfully treated, the balls must flow off their seats and not impair production. Operators had long assumed that the balls floated off their seats even though not all balls were accounted for in a ball catcher at the surface. The widely accepted explanation for this seeming discrepancy has been that some balls flow back to a highly deviated point in the well where they churn in the flow and smash against each other until they break into pieces that are small enough to flow out of the well.

However, some operators have become sufficiently concerned about ball material left in the well that they routinely mill the seats to make certain the flow path is clear. One operator found that after milling the ball-and-seat sleeves in 10 wells, estimated ultimate recovery increased significantly; the experiment was expanded to more than 300 wells. But elimination of a coiled tubing intervention to mill out plugs was one of the original drivers for adopting the ball-and-seat technology, and service companies have sought to eliminate the possibility of balls staying in place through numerous methods, including retrievable seats and valves; like most methods, however, that alternative also requires a coiled tubing intervention.

One of the issues with balls not seating or not floating off the seat after treatment is in the material used for the balls—predominantly phenolic, composite or metal alloy. These balls must be light enough to flow out of the well but strong enough to land in the seat at a high velocity without being deformed or damaged. Some industry experts believe these low–compressive strength balls are breaking before they have a chance to work. Under pressure, the balls may extrude, causing them to become stuck in their respective seats or one of the next seats uphole as they are flowed up the well.

Additionally, some types of these balls are constructed in layers and have inherent weaknesses in the layer bonding that may cause them to fail under pressure. If they land on the seat in certain positions relative to the layering, they may delaminate and break apart.

Schlumberger engineers have incorporated several solutions to address these concerns in the Falcon multistage stimulation method for uncentred wells. While testing various ball materials, the engineers also tested seat designs and discovered that spherical seats far outperformed typical cone-shaped seats. They also found that a magnesium alloy was superior to phenolic or composite ball material.

The lightweight magnesium used in the Falcon system balls minimizes ball extrusion; in addition, the balls are temperature insensitive, flow back intact and do not break on contact with the seat or during stimulation. They are rated to 68.9 MPa differential pressure and are easily milled. In one configuration of the Falcon system, the toe valves have multiple smaller balls that land in a single seat. These balls are able to easily pass through the upper seats to reach the lower sections of the well, but the total flow-through area remains large enough even at the lowest...
point of the well to eliminate the effects of friction pressure on fracture initiation (below). The material and design of the seats allow them to be easily and quickly milled.

No Limits

Engineers at Schlumberger have recently developed a variation on ball-activated systems that may be used in cemented wells. The technique uses balls or darts to activate sliding sleeves that provide stage isolation. Because this technique does not require seats of decreasing diameter to get the balls to TD, the technique can be used to stimulate a nearly unlimited number of stages in a single continuous operation.

The nZone multistage stimulation system includes a control line connected to sequential valves that make up part of the completion. To initiate the stimulation operation, a dart, which is pumped from the surface, lands on a C-ring—an incomplete circle—in the lowermost valve. The completion engineer then applies pressure against the dart, which opens the sliding sleeve and pressurizes the control line. This pressure is transferred to a piston in the valve immediately above it, which closes the C-ring, creating an O-ring with a reduced ID (next page, top).

The first stage of the stimulation is pumped, and during the flush stage, another dart is released. This dart lands on the now-compressed C-ring, isolating Stage 2 from Stage 1. The resulting increase in pressure forces the sleeve to slide for Stage 2 and the control line to become pressurized and close the next C-ring, which is then ready to catch the next isolation dart. Stage 2 is treated, and during the flush stage, another dart is pumped. When fracturing operations for all stages are complete, the well can be produced. The darts can remain in the well, but to obtain full wellbore access for future interventions, the darts must be milled out. Alternatively, the operator can deploy dissolvable darts.

Recently, in an effort to increase production and reduce completion costs per well, the operator of the Dagang field in the Huanghua depression of eastern China, which had previously drilled only vertical wells, changed to horizontal wells. The first commercial discovery in this field was made in 1963 in the Tertiary Guantao group. By 1996, this oil-bearing play had expanded to 564 km² [218 mi²] with proven original oil in place of 31 billion m³ [1.1 Tcf]. Additionally, the depression has estimated proven gas condensate reserves of 7.34 million t [54 million bbl]. Currently, there are 23 oil and gas fields in the depression, including 15 oil- and gas-producing fields in 24 development areas in the Dagang field. Annual production from this field is 4.3 million t [31.4 million bbl] of oil and 380 million m³ [13 Bcf] of gas.

This field has been traditionally produced through cased and cemented vertical wells. Because many wells of this type are required to produce these relatively low-permeability formations, the economics may be considered marginal despite the large production volumes. The operator recently set an oil production target rate for the field of more than 6,000 t/yr [44,000 bbl/yr] oil equivalent. Completing wells quickly and achieving incremental production gains in each well are the keys to reaching the operator’s objective. To do so, engineers must properly identify and complete as many pay zones per well as possible using appropriate technology, including horizontal drilling. Additionally, the operator calculated that vertical wells in the target formation would produce an average of 15 m³/d [94 bbl/d] of oil, while horizontal wells would produce an average 45 m³/d [283 bbl/d] using traditional completion techniques. To increase the return on horizontal wells, and after assessing the plug and perforate methodology, engineers opted for an nZone completion that included a rupture disc valve placed at the toe of the well to expose the formation for treatment of the first stage.

Unlimited numbers of stages. Using an nZone valve, operators ready the stage below the valve for treatment when a ball or dart lands in the seat of the sliding sleeve. Pressure increases in a hydraulic control line that connects numerous valves. When a lower nZone valve opens, stimulation fluids are pumped into the formation (yellow arrows). Pressure on the hydraulic line shifts a sleeve downward, causing a C-ring to move into the smaller inner diameter of the valve and form a smaller diameter circular seat that is ready to receive the next dart or ball to begin the process again. Because the seats are not in descending size, the process can be repeated for as many stages as are required to stimulate the entire well.

The horizontal section of the well was completed as a 5 1/2-in. monobore casing cemented in an 8 1/2-in. hole and treated via a four-stage stimulation. The disc valve at the shoe was opened at 3,500 psi [24 MPa] above the casing test pressure, which allowed engineers to test the casing as part of the cementing operation. After the disc valve ruptured, which manifested as a sudden pressure drop observed at the surface, engineers first performed a minifracture to determine formation parameters and confirm injectivity into the first zone; they followed that with the first stimulation stage.

Completion engineers launched a ball from the surface during flush to isolate the first stage and begin Stage 2. When the ball landed in the first seat, the pressure increased, and engineers shut down the pumps. When pumping resumed, a sudden drop in pressure indicated the valve had opened and the formation was fractured using less than 4,800 psi [33 MPa] pressure as measured at the surface. Engineers attribute this low fracture pressure to the helical port design of the Falcon fracture valves. These steps were repeated until all four stages were stimulated, during which fracture initiation pressures from Stage 1 to Stage 4 were 5,100, 4,800, 5,800 and 5,500 psi [35, 33, 40 and 38 MPa], respectively. That pressures were different at each stage is a strong indication that all four stages were treated.

Unlike most other wells in the area, the treated well was able to flow back immediately and without artificial lift. Production was 8 to 10 times greater than that of a vertical offset well and was expected to be triple that of an unstimulated horizontal well. After five weeks, because flow rates were higher than those in other wells in the field, the operator was able to produce the well using a less expensive electric submersible pump instead of a rod pump. Payout from the well in which the operator used the nZone system was calculated at two and one-half months in contrast to four months for the unstimulated horizontal well and eight months for vertical wells. The operator plans several more wells using MSS technology.

Not One Size Fits All

As MSS technology rapidly transitions from emerging to mature status, the industry remains uncertain about how best to apply it. Exploiting liquid-bearing shales and other ultralow-permeability formations is a relatively recent endeavor, and long-term data are nonexistent.

For example, while engineers have doubled the length of laterals in the Bakken Shale in the past decade, the stimulation stage count has increased 10-fold. At the same time, as lateral lengths have increased, operators have generally decreased stage spacing and the amount of proppant and fluid pumped per stage. And although data seem to indicate a limit to the rate of return on investment from more stages per well—about 37 stages in the Bakken—long-term economic analysis of these plays is currently impossible; these wells have not been producing for enough time to generate sufficient data for meaningful decline curve analysis.

Similarly, the industry is still learning how to get the most from the shales. For example, the industry does not yet fully understand the storage mechanisms of the Eagle Ford Shale and the factors that differentiate a good producing area from a mediocre one. Only data gathered over time will answer the economic and reservoir questions of unconventional resources, even as technologies emerge to take advantage of that knowledge.