The Challenge of Completing and Stimulating Horizontal Wells

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Although drilling horizontal wells has become almost routine, completions can include securing zonal isolation, taken for granted in a conventional vertical well.

Vertical well technology took over half a century to progress from barefoot openhole completions to the range ofcased-hole completions available today. Driven by the same need to selectively produce and treat individual zones, completion engineers are pushing horizontal well technology along the same road in less than a tenth the time.\(^1\)

At first sight, zonal isolation might not seem as important in a horizontal well as in a vertical well. The horizontal well should ideally tap one formation and produce from the entire horizontal interval. Experience drilling and producing horizontal wells, however, shows that reservoirs are often horizontally heterogeneous. With sufficient subsurface knowledge, oil companies can exploit heterogeneity by directing horizontal boreholes through natural fracture systems, or through facies and faults tapping several separate producing formations. This requires zonal isolation. Isolation may also be needed if the borehole drifts in and out of the target reservoir because of insufficient geological knowledge or poor directional control.

When horizontal boreholes are drilled to tie into the natural fractures of a tight formation, such as in the Austin chalk fields of south Texas and the Rospo Mare field offshore Italy, zonal isolation is being seen as mandatory.\(^2\) Initial pressure in naturally fractured formations may vary from one fracture to the next, as may the hydrocarbon gravity and likelihood of coning. Allowing them to produce together permits crossflow between fractures and a single fracture with early water breakthrough, which jeopardizes the entire well’s production.

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\(^1\) For contributions to this article, thanks also to: Tom Griffin, Dowell Schlumberger, Houston, Texas, USA and Michael Economides, Leoben University of Mining and Metallurgy, Leoben, Austria.

\(^2\) For an introduction to horizontal well technology, see other articles in this issue, also:

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selectively treat the right zone. Today, zonal isolation is achieved using either external casing packers (ECPs) on slotted or perforated liner or by conventional cementing and perforating (see “Which Completion?” page 58). In this fast-moving technological area, oil companies choose which method to use depending on their experience and the producing conditions. In the long run, conventional cementing and perforating offer the most reliable isolation. It is fast becoming the favored technique in most fields outside the USA and is mandatory if the well is to be hydraulically fractured.

ECPs are mostly used in naturally fractured formations such as the Austin Chalk and Rospo Maer chalks. Attached to the outside of the liner, ECPs are reinforced, inflatable rubber diaphragms that are inflated with mud or cement to make a seal against the formation (right). Since ECPs inflate radially, they work less well in oval holes than in circular holes.

2. ECP is trademark of Baker Hughes Incorporated.
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For an introduction to horizontal well technology, see other articles in this series, also.


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Cementing

The elements leading to a successful horizontal cementation are similar to those required for a conventional vertical job. It is the particulars that make the difference.4 As with every cement job, operators try to displace as much of the mud and solids from the annulus with cement as possible. The idea is to leave no continuous channels for fluid communication behind the liner. This is intrinsically harder to achieve in the horizontal environment than in the vertical. In the vertical well, channels may develop but they usually lack continuity. In the horizontal environment, gravity causes continuous channels to develop on the top side of the liner because of fluid separation in the cement and on the bottom side because of nondischarged cuttings.

Centralizing the liner is the first step in a successful mud displacement. In horizontal wells, gravity pushes uncentralized pipe to the low side of the hole trapping undisplaceable mud there. Other causes of eccentricization can be the zigzag nature of horizontal wells from the natural resonance of drilling motors, which can create a corkscrew-shaped hole, and planned changes in hole direction during drilling. Two types of centralizer, rigid and bow-spring, are used to counter eccentricization.

Rigid centralizers generally offer better results for in-gauge horizontal wells; certain types with plenty of space for circulation offer the additional benefit of increasing local turbulence, aiding mud displacement. Washedout sections of hole require bow-spring centralizers. Some manufacturers fit centralizers with special bushings at each end to reduce torque when the liner is rotated to break down the mud’s gel strength prior to pumping cement. To reduce drag when lowering liner into a horizontal hole, centralizers can be mounted over stop collars so they flatten as they are pushed through constrictions in the hole (above, left). Without stop collars, the centralizers would be pushed along by liner collars and expand.

Eccentrization in horizontal holes may also result from using heavy cement. When cement is pumped downhole, the liner becomes heavier and will sit low in the mud-filled hole, possibly compressing bow-spring centralizers or causing rigid centralizers to sink into the formation. This creates a narrow channel on the low side of the annulus and impedes mud displacement there (top). As the cement moves along the annulus, however, casing buoyancy will increase and bowspring centralizers may recover, opening up the low side of the annulus. But then, it is generally too late to improve displacement.

A way to improve centralization is to use a smaller-diameter liner. This means less cement pushing the liner downward during displacement and more standoff from the borehole wall, a defined parameter that correlates with displacement efficiency (bottom). The completion design, however, may preclude using a smaller liner.

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The design of the cement slurry must balance several conflicting requirements. The slurry should have low yield stress to promote turbulent flow, essential for maximizing displacement, and excellent fluid loss because it is exposed to possibly thousands of feet of permeable reservoir. But most important, the slurry must be stable, with no sedimentation or development of free water. Sedimentation, the separating out of the cement's solid components, leads to low strength, highly porous cement. Free water developing on the high side of the hole may create an open continuous channel. Tests by Elf Aquitaine and Institut Français du Pétrole (IFP) showed that a slurry with 0.2 percent free water would result in a channel up to 0.4 in [10 millimeters] high at the top of 7-inch liner/10-inch borehole annulus.3

The Elf and IFP researchers report three options to enhance slurry stability, depending on downhole temperature:

- Using dispersants to encourage the formation of ettringite, a mineral formed during setting that binds cement grains together (right).
- Viscosifying the interstitial water with latex emulsions.
- Mixing solid inert elements 10 to 100 times smaller than the cement grains to occupy interstitial gaps between grains and prevent water from separating.

**Flow rate ratio**, the ratio of flow rate during mud displacement between the top and bottom sides of the liner, as a function of liner standoff. If the liner sits low in the hole, flow on the bottom side may drop to near zero. If the liner is perfectly centered, flow rate ratio is unity and displacement is optimum. The parameters $w$, $r_h$, and $r_c$ are respectively the minimum separation of liner and hole, hole radius, and liner radius.
Another ingredient for successful cementation in horizontal wells is easily displaceable mud, particularly with low gel strength. Pipe movement is the key to breaking down mud's gel strength, and pipe rotation has proven more effective than reciprocation. Recently, special hangers equipped with bearings have been developed for simultaneous rotation and reciprocation (below).

Reciprocation is typically with a stroke of around 10 to 20 feet [3 to 6 meters] every minute, rotation is between 10 and 20 rpm. Both are continued until the plug bumps on bottom. Rotation has the additional benefit of forcing cement around the casing and improving displacement on the narrow side of the annulus. In horizontal wells, hole torque and drag may preclude liner movement—theoretical drag models have been developed to predict when it may be impossible to move the liner.

The cement should be displaced at a rate that preserves a stable fluid interface between the slurry and mud, preferably in turbulence. This requires a rheologically stable slurry with low yield stress, low plastic viscosity and excellent fluid loss control, properties that can be ensured with latex-based additives such as used in the WELBOND® and GASBLOK® services.

Finally, special consideration must be given to the float equipment at the end of the liner that prevents cement flowback. Flowback can be a problem in horizontal wells because the hydrostatic pressures of the slurry and mud at the end of the hole may be similar. For near-balanced conditions, most operators prefer the spring-loaded flapper or poppet equipment, although specially designed ball-type float valves have been claimed to work satisfactorily in tests with a pressure difference as small as 5 psi between the fluids (top).

**Perforation**

Oil companies have been reluctant to cement and perforate the entire length of a horizontal well. With a well drilled up to 3000 feet [900 meters] through one producing sand, they see perforating as prohibitively expensive. Recently, it was shown that perforating the entire length of a horizontal well was unnecessary, particularly when tapping a thin reservoir—the same production can be obtained by perforating a fraction of the full length. Oil companies also recognize that most reservoirs are heterogeneous enough horizontally to warrant selective production. The trend is therefore toward perforating shorter intervals.

Other trends include a high shot density for hydraulic fracturing to reduce the pressure drop across casing; and for formation sand control, only downward perforation—experience in highly deviated wells shows it is difficult to gravel pack upper perforations.

**Simultaneous rotation and reciprocation of liner during cementing. This helps break down the mud's gel strength, facilitating mud displacement. Special liner hangers had to be developed that permit both movements.**
The challenge in perforating horizontal wells is getting the guns along the borehole to the correct location, or “depth.” Wireline-conveyed guns are limited to about a 75-degree deviation. Beyond that, perforating guns must be pushed down with tubing (tubing-conveyed perforating—TCP), coiled tubing (CT) or drillpipe. In reviewing the perforation of horizontal wells, Amoco Production Co. observed that while TCP is expensive, the system is robust and provides a wide selection of guns. On the other hand, the CT system’s savings in cost and time may be more important than the smaller size of CT-conveyed guns (left).

Other issues in horizontal perforation are penetration depth and centralization. Generally in a horizontal completion, shots firing upward may traverse more hole and cement than downward shots. Centralizing the gun obviously helps to maximize penetration, but currently centralization is only possible with tubing- or drillpipe-conveyed guns. For TCP, Amoco uses the largest gun that can be fished, determined from the tubular dimensions of the well, and equips it with the best available centralization.

Depth control, crucial for perforating vertical wells, may be less critical in the horizontal environment. The accuracy required depends on reservoir heterogeneity—the more heterogeneous the producing formation, the more accurate the depth control.

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* Mark of Schlumberger
+ Mark of Dowell Schlumberger

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*Perforating in horizontal hole with coiled tubing-conveyed guns. Depth control, so vital in vertical wells, may be less crucial in the horizontal environment. However, it is more difficult. The conventional gamma ray correlation method is compromised because most formations display only small lithology variation in the horizontal direction. The surest depth control comes from identifying a short pup joint inserted in the liner just above the producing zone with a casing collar locator (CCL) or a radioactively tagged liner section with a gamma ray tool. Both techniques are performed with wireline equipped coiled tubing.*
**Which Completion?**

**Open hole**
How most horizontal wells were initially completed, but now used only in the homogeneous reservoir with enough geomechanical strength to support itself. No zonal isolation is possible with this type of completion.

**Slotted liner in open hole**
The easiest completion after open hole. Slotted liner can support weaker formations, but should not be used where sand production occurs. The sand will plug the slots or be produced through them. No zonal isolation.

**Open hole, cemented off-bottom**
Similar to an openhole completion except that the top zone is filled with cement, to isolate a gas cap perhaps, and then drilled out. The technology requires the isolation of the lower horizontal portion of the wellbore from the section being cemented using a highly viscous, crosslinked polymer plug up to 200 feet (60 meters) long. ¹

**Prepacked liner in open hole**
The easiest solution for sand control. A resin-impregnated sand is trapped between two concentric screens. Prepacked liners prevent collapsed sand from entering the well but do not discourage the sand from collapsing. The sand may form a zone of reduced permeability around the outer screen and impede production.

Gravel packing
The ideal completion for weak formations, but hard to achieve in a horizontal well. The easiest method is to leave the well openhole and pack gravel around a slotted liner or, for insurance, around a prepacked liner. For details, see "Sand Control" on this page.

Sand Control
The most widespread technique for sand control in horizontal wells utilizes prepacked liners, comprising two concentric screens packed with resin-coated particles. They are usually set in open hole, though Elf recommends installing a slotted liner first to facilitate workover.9 Prepacked liners prevent sand from entering the wellbore, but they do not halt formation collapse. Thus, produced sand accumulates around the liner and may block production.

A conventional gravel pack, in which gravel completely fills the annulus, prevents sand collapse, but is hard to achieve in highly deviated wells.10 Chevron reports considerable success in the Gulf of Mexico for 70- to 80-degree wells. Most gravel packing in horizontal holes is done open hole and, for insurance, around prepacked liners.

Best results are to be expected by pumping the gravel and carrier fluid down the annulus and up the liner. This allows the gravel to accumulate starting from the end of the well minimizing the chances of bridging. The carrier fluid should have excellent suspension properties to carry the gravel, and high leakoff to encourage gravel placement. The gravel should preferably be light and as close in density to the fluid as possible, again to increase suspension. Dowell Schlumberger's nondamaging PERMPAC© carrier fluid and low-density ISOPAC© gravel substitute were designed to satisfy these requirements and are expected to eliminate the need to perforate only downward for gravel packs in horizontal cased hole. Upward perforation in deviated cased wells are considered risky, too likely to go unpacked and later produce sand.

Matrix Stimulation
Intersection of the wellbore with natural fractures is often a goal of horizontal drilling. But just as these channels are potential conduits for oil or gas production, they are also possible thief zones during drilling, causing deeply penetrating damage to the formation. Oil companies suspect that matrix damage may be exacerbated in horizontal wells because the drilling tends to produce finer cuttings that plug formation more easily.11 A cleanup program reconditions these fractures, as well as secondary fractures connected with them, and/or restores the original matrix permeability through injection of acid or other solvents at below fracturing pressure.

Because horizontal wells intersect long intervals of producing formations, cleanup treatments can require huge volumes of chemicals—in excess of 100 gallons per foot for thousands of feet! Chemical costs become prohibitively expensive if the stimulation fluids disappear down a few permeable channels and open communication to unwanted gas or water zones. This is avoided by using diverting agents such as bentonite acid, wax beads, foam or micro-

11. For details on horizontal stimulation see:
For an overview see:
scoplastic oil-soluble fibers. These block permeability during the treatment but dissolve once production begins. Nondestructible diverting agents such as ball sealers are not recommended because they may remain in the horizontal section after the treatment and even after the well is put on production, compromising future workover.

In cased and perforated completions, acid can be injected at precise depths through coiled tubing with the Formation Selective Treatment (FST9) System, which comprises an injection port between two inflatable packers (left). In openhole or slotted liner completions offering no zonal isolation, the recommended procedure is to pump acid through coiled tubing that is initially pushed to the end of the hole. During pumping, the coiled tubing is slowly withdrawn and diverting agents are released every 50 to 100 feet to seal off the already cleaned section of the hole. The rate of coiled-tubing withdrawal depends on pumping rate, reservoir permeability and skin damage, and the required cleanup radius. Successful matrix cleanup has been performed this way at rates less than 25 gallons per foot.

Matrix acidizing with the Formation Selective Treatment (FST9) system on coiled tubing. The FST9 tool comprises an injection port between two inflatable packers. A circulating valve just above the tool obviates the need to push large volumes of well fluid into the formation before the acid. For less efficient spotting of acid, coiled tubing can be pushed to the end of the hole and slowly withdrawn while acid and diverting agents are pumped.
Hydraulic Fracturing

Hydraulic fracturing, using either acid or sand, improves production by creating fractures through high-pressure pumping. How successfully induced fractures drain a reservoir depends on their orientation, reach, and fluid conductivity.

Near the well, fracture orientation is dictated by the complex near-wellbore stresses. As the fracture develops away from the wellbore, however, it will align itself perpendicular to the earth's minimum stress (right). At depths more than about 2000 feet, this is in a horizontal direction, so the fracture plane will be vertical.

A key factor in determining the productivity gain from induced fractures is their relative orientation to the wellbore. If the well runs perpendicular to the minimum stress direction, fractures will develop along the well. The entry point into any fracture will be through an extended length of perforation (below).

On the other hand, if the minimum stress parallels the well, the fractures will develop transversely, potentially increasing the drainage area of the reservoir. The disadvantage is that the limited contact of each fracture with the wellbore acts like a choke, impeding injection of fracturing fluid and proppant and then afterward the flow of hydrocarbon. A partial solution is to multiply perforate the point of intersection or to completely cut the cemented liner with radial perforating jets or a radial blast of fluid-conveyed sand, as provided by the ABRASIJET service, for example.

If the earth's stress is known, the well can be directed to take advantage of either scenario—transverse or longitudinal induced fractures. Borehole direction can be accurately kept on target with directional drilling techniques (see "Horizontal Drilling Comes of Age," page 22). The earth's stress can be determined from minifrac tests, wellbore ovalization (observed with a four-arm caliper logging tool in nearby vertical wells), or by observing the orientation of natural fractures with imaging tools such as the Formation MicroScanner tool.

But it must be ensured that the planned horizontal well will better the performance of an equivalently stimulated vertical well and pay back the extra cost it takes to drill and stimulate horizontally. Recent theoretical work permits such a comparison (top, right). The results depend on whether the horizontal fractures are longitudinal or transverse to the well, their number and size, their fluid conductivity, formation permeability and, for transverse fractures, the skin that develops at the intersection point between fracture and well (above, right).

Having established that fracturing the horizontal well is economically desirable, the operator must choose among a variety of methods to selectively isolate each zone during the fracturing operation. This used to be done with permanent bridge plugs that were later drilled out. But this technique takes time and creates debris that can

- An induced fracture leaving a horizontal well and seeking an orientation perpendicular to the earth's minimum stress, marked with arrow.

- Theoretical prediction of the relative productivity indexes of a longitudinally fractured horizontal well and a conventionally fractured vertical well. The ratio depends on the relative length of the horizontal section, \( L \), compared with the thickness of the producing zone, \( h \).

- Multiple transverse fractures—probably the best way to tap a reservoir. A drawback is the flow constrictions that occur at the intersection between each fracture plane and the well.

Three methods for stimulating horizontal wells selectively. The traditional method (left) uses a resettable packer to seal the top of the zone and millable bridge plugs to seal the bottom. Debris from drilling the plugs out may obstruct the formation. A second method uses straddle packers set by reciprocating the tubing. Setting must be done after the tool has been moved opposite the zone just perforated. A third method uses a retrievable bridge plug on the bottom. Other more exotic ways to isolate a zone for stimulation include multiple completion packers with tubing equipped with sliding sleeves, liners equipped with polished bore receptacles (PBRs), sliding sleeves, or aluminum disks that can be dissolved with acid.

Damage the formation. Now there are several combinations of traditional and new hardware that do a better job (above):

- **Retrievable bridge plug/packer combinations**: These offer simplicity but can cause problems if the packer leaks during pressure testing. If the plug cannot be retrieved, it has to be milled.

- **Retrievable straddle packers**: These are set by reciprocating the drillpipe. But during tripping, previously fractured intervals are exposed to kill fluid unless a temporary plug is set. Positioning the tool accurately across a number of perforations may present a problem.

- **Multiple completion packers with sliding sleeves in the tubing**: Production packers have to be set only once; each treated zone is mechanically isolated: and CT-operated sliding sleeves in the tubing allow individual testing from each zone. The major disadvantage of this system is the reduced flow caused by the small tubing diameter. In addition, recompletion or logging of the well would require retrieval of the production packers.

- **Multiple polished bore receptacles (PBRs)** in the liner used with a retrievable seal assembly that close the well at PBR depth: This simple concept requires only reciprocation of the tool assembly to open and seal the well. Problems arise, however, when the casing cannot be set at the correct depth—the PBRs will automatically be off too. The PBRs can also be damaged by the trip downhole or during operation if proppant remains in the wellbore.

- **Sliding sleeve collars or aluminum disks built into the casing**: The sleeves can be difficult to open and close, and this problem can also prevent the running of packers. Aluminum disks dissolve in acid, making a perforating tool string to go in the hole unnecessary. However, difficulty has been experienced dissolving the disks and fracturing through the cement.

Perhaps the most successful fracturing program in horizontal wells has been in the Dan field, a low-porosity chalk reservoir in the Danish sector of the North Sea operated by Mørsk Olje og Gas AS (see "Exploiting Reservoirs with Horizontal Wells: the Mørsk Experience, page 11"). In a 1987 study, the productivity of a nonstimulated horizontal well was shown to be no better than a conventional, fractured deviated well, yet cost more. Even a matrix-acidized horizontal well hardly offered better production. The study concluded that horizontal wells in the area could compete economically only if they were fully stimulated by fracturing. There were additional risks to such a procedure in the low-permeability chalk, but Mørsk Oil decided they were worth taking.

Three horizontal wells were fractured with up to seven fractures per well (next page, middle). Mørsk Oil reports that once on stream these three multistimulated horizontal wells accounted for 25 percent of the field's production. At the time, the field had 41 producing wells.

In 1989, more than 100 horizontal medium- and long-radius wells were drilled and the number seems to be doubling every year. With the exception of a few major field developments, these wells have been paid for from R&D budgets or by special funding.

Proponents of horizontal well technology foresee its dramatic proliferation in the future with perhaps up to 50 percent of all wells being drilled horizontally. The advocates predict that combinations of vertical, directional and horizontal wells, whether fractured or unfractured, will be used to create an "underground architecture."

For this dream to be realized, experience completing and evaluating horizontal wells will be needed in a far greater range of reservoirs, not just in ones with special needs or problems. Operators will require conclusive proof that horizontal wells are the most economic producers. Once the proof is there, the technology will move into the mainstream.

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Seven fractures, shown schematically, induced in a horizontal well in the Dan field in the Danish North Sea by Maersk Oil & Gas A/S. Just three such wells provide 25 percent of the field’s production from a total of 41 producing wells. A pilot hole was drilled first to locate the dip of the producing Maastrichtian formation, the overlying low-permeability Danian formation and the 50 percent water saturation level. Adapted from reference 14.