Screenless Methods to Control Sand

Combining proven oilfield technologies allows operators to achieve solids-free production in many of today’s challenging oil and gas developments. This approach provides viable, cost-effective alternatives to conventional sand-control methods for completion or rehabilitation of wells that produce sand, especially when applied rigless—without conventional rigs.

Produced sand causes various problems from removal, handling and disposal of fill inside casing or surface equipment to serious well-completion failures. These problems often compound, jeopardizing future remedial well interventions and long-term wellbore viability. Leaks, production delays, low hydrocarbon recovery factors or loss of well control may occur if sand erodes wellbore equipment or surface wellheads, pipes and facilities. In a catastrophic failure, access to reserves can be lost if costs to sidetrack or drill a new well are prohibitive.

In some reservoirs, weakly consolidated, but relatively competent zones can be completed without installing mechanical screens to keep sand—formation grains and migrating fines, or small rock particles—from entering a wellbore. In the past, operators have used gravel packing or frac packing in formations of this type. These two methods rely on the particle-bridging characteristics and filter mechanisms of sand-exclusion screens in open hole or inside casing with annular gravel packs and also propped hydraulic fractures in the case of frac packs.

Screenless completions use techniques other than conventional “internal” packs to prevent perforation failure and subsequent production of formation solids (next page). Screenless methods maintain well productivity and sand-free inflow by combining one or more of the following six field-proven technologies:

- optimal perforation phasing, orientation and size
- wide tip-screenout (TSO) fractures across all perforations
- proppant-flowback control
- chemical formation consolidation, or stabilization
- cementing unwanted permeable gravel-pack intervals
- selective coiled tubing treatments.

When planned and implemented carefully, these techniques control sand, reduce overall cost and risk, enhance productivity and improve hydrocarbon recovery.

This article reviews screenless methods and associated rigless techniques that came into more widespread use during the mid-to-late 1990s. We present results from applications in Saudi Arabia, the Gulf of Mexico and Italy to illustrate the effectiveness of oilfield technologies, new and old, in innovative combinations that prevent sand production.

Andrew Acock
Aberdeen, Scotland

Norbert Heitmann
Caracas, Venezuela

Steve Hoover
Houston, Texas, USA

Badar Zia Malik
Stavanger, Norway

Enzo Pitoni
Eni S.p.A. E&P Division
Milan, Italy

Claud Riddles
J.M. Huber Corp.
Houston, Texas

J. Ricardo Solares
Saudi Aramco
Udhaiyyah, Saudi Arabia
Screenless completions. Rigless methods prevent sand influx without screens or annular packs by combining optimized perforating, chemical formation consolidation, or stabilization, and tip-screenout (TSO) fracturing with proppant-flowback control fibers to create an ‘external’ pack (top left). Resin-coated proppants (RCP), PropNET hydraulic fracturing proppant-pack additives, or both, help stop proppant and formation sand production (top right). Formation consolidation involves injection of a resin system into the formation to form a stronger bond between individual grains (bottom left).
Rigless Interventions

Screenless completions avoid the limitations and productivity restrictions of internal gravel packs and screens. Screenless completions do not restrict wellbores across pay intervals. This full-bore access provides additional flexibility for subsequent well logging and data gathering, remedial repairs and recompletions, reservoir monitoring and production management, and control of water or gas inflow.

In addition to simplifying completion operations and reducing installation risks, this approach decreases cost by eliminating screen assemblies and associated equipment, complex downhole tools, and the fluid volumes and pumping operations that are required to place gravel around screens (above). Screenless completions can provide primary sand control in newly drilled wells or lateral side-tracks, especially for casing sizes and wellbore configurations that preclude the installation of mechanical sand-exclusion screens. In addition, they are used to complete bypassed zones in existing wellbores. Wells without screens and gravel packs that begin to produce sand can be recompleted using screenless techniques.

Screenless techniques do not require drilling or workover rigs. These methods can be performed using coiled tubing, which further reduces completion and remedial intervention costs. This makes screenless methods particularly attractive and cost-effective for initial completion of bypassed zones. These methods are also applicable for repairing wells with plugged gravel packs or eroded screens.

Evolving Techniques

In the early 1990s, companies began evaluating methods to prevent sand influx by mitigating formation failure and perforation breakdown in unstable formations. Since that time, operators and service companies have worked together to develop and optimize rigless sand-control techniques. These efforts led to optimized perforating practices for sand management—control and prevention—as well as increased hydraulic fracturing and frac packing for sand control.1

Amoco used “up-and-under” fracturing in the North Sea Valhall field during the 1980s.2 Statoil applied a similar technique called indirect vertical fracturing (IVF) to control sand in the North Sea Gullfaks field without installing screens and gravel packing.3 These methods involve perforating competent shale or other high-strength intervals adjacent to weaker target pay zones, followed by fracturing treatments designed to grow vertically into the producing formation (next page). Initiating hydraulic fractures from a strong, stable zone delays or prevents the onset of sand production resulting from pressure depletion.4 The IVF technique requires detailed formation lithology and in-situ stress data, but is effective when applied judiciously.

Dalen Resources Oil & Gas Company and Ely & Associates perforated limited 30-ft [9-m] intervals at 0° phasing and used TSO fracturing to prevent sand production.5 The objective was to create a wide, stable hydraulic fracture packed with resin-coated proppant (RCP) to reduce sandface drawdown pressure and stop proppant flowback as well as produced sand. PT. Caltex Pacific Indonesia, now a division of ChevronTexaco, used a similar technique and a 180° perforation phase angle in Duri field, a heavy-oil steam-flood project in Indonesia.6 During the mid-1990s, Amoco Norway, now called BP Norge, successfully used the same general approach to prevent chalk production from more than 70 horizontal wells in weak North Sea chalk formations.7 Perforating short intervals—5 ft [1.5 m] or
less—at the beginning, or heel, and the bottom, or toe, of horizontal sections induced hydraulic fractures across all perforations. Rigorous testing confirmed that, within certain limitations, RCP could control proppant flowback.

Fracture conductivity—width—affects the pressure drawdown that can be applied before formation sand is produced from perforations not covered by the fracture and proppant pack. Arco E&P Technology, Arco Indonesia, Inc. and Vastar Resources, an Arco subsidiary at that time, developed and applied a technique to predict fracture geometries and properties that prevent sand production. Corpoven, formerly a unit of Petróleos de Venezuela S.A. (PDVSA), also applied this concept to control sand production from deep wells in high-stress formations. In addition, forcing dynamic fractures to close immediately after stimulation operations minimized early onset of sand production.

Subsequently, operators placed greater emphasis on controlling production rates and drawdown pressures during cleanup and recovery of treatment fluids, well testing and initial production to ensure successful fracturing treatments. Because perforation failures initiate at a critical pressure, keeping differential pressures below that critical level during production helps maintain long-term stability. Operators can establish production rates that optimize drawdown pressures during treatment cleanup and hydrocarbon production to prevent formation and perforation failure that might initiate sand production immediately after completion operations.

These techniques contribute to successful screenless completions. However, optimizing cleanup procedures after hydraulic fracturing requires careful consideration of several factors. Flow regime—two- or three-phase flow—viscosity of returning stimulation and reservoir fluids, maximum allowable flow velocity in perforation tunnels and proppant type play important roles in maintaining screenless completion integrity after treatment execution.

Results vary from application to application, but screenless methods generally provide effective sand control. Operators attribute this success to teamwork, efficient completion practices and lessons learned from worldwide experience, in addition to effective fracturing treatment designs and execution, and willingness to try new technology and combinations of techniques. Screenless techniques create a variety of well-completion opportunities that vastly outweigh any limitations from the physical absence of mechanical screens.

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**Early screenless completion in the North Sea.** The ‘up-and-under,’ or indirect vertical fracturing (IVF), technique was used by Amoco in the Valhall field to control chalk production, and by Statoil in the Gullfaks field to control sand in reservoirs with relatively thick, interbedded sandstones and shale layers. Hydraulic fracture treatments designed to propagate into a nearby hydrocarbon-bearing formation are initiated by perforating a shale or stronger zone. Fracture height and length grow rapidly through the weaker producing interval, with the initial fracture section in the more competent layer acting to exclude formation sand from the wellbore.
Perforating and Fracturing

For new wells and bypassed zones in existing wells, screenless completions begin with optimized perforating practices. This first step addresses perforation phase angle and orientation, perforated interval length, and the size and number of holes, or shot density. For successful sand control and fracturing treatments, perforating strategies should be designed so that perforations lie in or near the preferred fracture plane (PFP), or maximum in-situ stress direction.

After perforating, TSO fracture treatments are performed to inflate dynamic fractures and create wider propped widths that generate a proppant ring, or “external pack” (right). These specialized fracture treatments bypass near-wellbore damage and stimulate well productivity by connecting individual formation laminations or layers and establishing a conductive, stable and long-lasting flow path from reservoir to wellbore.

Screenless methods achieve success only when well-developed TSO fractures with stable proppant packs cover all perforations and prevent sand from entering the wellbore. Untreated perforations that are not optimally aligned and directly connect formation and wellbore leave potential pathways for sand production.

If stress directions are unknown, a 0° phase angle maximizes the number of perforations that communicate with a hydraulic fracture (next page, top). If stress directions are known, perforating guns with 0° or 180° phasing oriented in the PFP mitigate tunnel failure and sand influx, both with and without consolidation treatments (next page, bottom). Optimal phasing or oriented perforations also reduce near-wellbore flow-path restrictions, or tortuosity. Tortuosity increases fracture-initiation pressure and pressure drops across completion intervals that occur during injection of fracturing fluids and proppants.

Orienting perforations in the proper direction requires knowledge about formation in-situ stresses and directions along with the technical capability to economically orient perforating guns. Special tools such as the oriented four-arm calipers, DSI Dipole Shear Sonic Imager and FMI Fullbore Formation MicroImager tools, supplemented with local knowledge and regional stress maps, help engineers determine stress magnitudes and directions.

In the past, only motorized downhole wireline tools or tubing-conveyed perforating (TCP) systems rotated from surface could actively orient guns. Recently, however, Schlumberger deployed the Wireline Oriented Perforating Tool (WOPT) to orient guns in near-vertical and high-angle wells—inclination angles from about 0.3° up to about 60°—and the OrientXact tubing-conveyed oriented perforating system for near-horizontal wells.

Because of the emerging status of screenless techniques, perforations in vertical wells should be restricted to a maximum interval of 20 to 40 ft [6 to 12 m] at least until experience dictates that this interval can be extended confidently. For high-angle wells with inclinations greater than 10°, where multiple fractures may develop, perforated intervals should be less than 6 ft [1.8 m]. Limiting perforated-interval lengths improves fluid placement, and increases the probability that TSO fractures will cover the perforations and form an effective external pack completely around the wellbore. Shorter intervals also improve proppant packing by providing high net pressure near the wellbore.

Completion engineers select perforating charge type and shot density based on required pressure drops while pumping the fracture treatment and producing the well. Perforation diameter must be sufficiently large to avoid proppant bridging and premature screenouts, but small enough so that after the dynamic fracture closes, the propped width at the wellbore completely covers the entrance holes in casing walls, thus blocking sand influx. Limiting the number of shots minimizes untreated perforations.

Hydraulic fracturing reduces the pressure drop across completion intervals, which minimizes perforation failures and sand production. The external pack and large surface area of proppant packs created during TSO fracturing also prevent sand from entering a well. Most screenless stimulations include additional measures to stabilize the proppant pack.
Controlling Proppant Flowback

Propped fractures extend past near-wellbore drilling and completion damage that reduces permeability to create a conductive, linear flow path to the well. Like produced sand, proppant flowback is detrimental to well productivity and producing operations, and also fracture stability. Screenless completions lack internal annular gravel packs and mechanical screens inside the casing to stop sand from entering the wellbore with produced fluids. It is imperative that proppants remain inside hydraulic fractures, especially when formations must be chemically consolidated.

Proppants flowing at high rates erode completion equipment, tubulars, control valves and wellheads. In low-rate wells, proppants moving back into a wellbore can settle inside the casing and cause production to cease if productive intervals become completely covered. Proppant flowback also contributes to formation failure and perforation collapse, creates pathways for formation sand influx, and reduces production.

Specialized materials, such as resin-coated proppant (RCP) and Schlumberger PropNET hydraulic fracturing proppant-pack additives, or both applied together, help maintain fracture stability and integrity.

Several types of RCP are available, but only a few are suitable for screenless completions. Curable RCP interacts with treatment fluids and may set up in the casing after a premature screenout, making removal difficult. Precured RCP does not provide sufficient flowback control and should not be used in screenless completions in any case because the resin functions primarily to increase crush resistance. In general, a partially cured RCP is preferred because it minimizes fluid interactions and provides fracture stability while lowering the risk of proppant packing off and setting up inside the wellbore.


11. In standard fracturing, the fracture tip is the final area that is packed with proppant. A tip-screenout design causes proppant to pack, or bridge, near the end of the fractures in early stages of a treatment. As additional proppant-laden fluid is pumped, the fractures can no longer propagate deeper into a formation and begin to widen or balloon. This technique creates a wider, more conductive pathway as proppant is packed back toward the wellbore.


Optimal perforation phase angle. From rock mechanics, we know that hydraulic fractures propagate in the direction of maximum horizontal stress ($S_h$) or along the preferred fracture plane (PFP). When in-situ stress directions are unknown, a 0° perforating-charge phasing increases the probability that all perforations will connect with the TSO fracture. Perforations at other angles—30, 60 and 90° phasing—may not intersect the fracture.

Orienting perforations in the right direction. If in-situ stress directions are known, perforating guns with charges at 0° or 180° can be aligned in the preferred fracture plane (PFP), perpendicular to the minimum horizontal stress direction ($S_h$), so that the TSO fracture will cover all perforations. Proper orientation reduces or eliminates complex near-wellbore flow, or tortuosity, which increases fracture initiation and treatment pressures.
PropNET fiber technology uses randomly oriented carbon fibers that create a physical, rather than chemical, barrier that reinforces proppant packs and inhibits flowback (below left). The fibers are added continuously to fracturing fluids at the wellsite and mix with proppants during pumping. Experience indicates that PropNET fibers allow immediate flowback to improve treatment-fluid recovery after fracturing. This capability is attributed to the building of a mechanically reinforced network that interlocks proppant grains. Unlike RCP, this technology does not depend on temperature-sensitive curing processes or other chemical reactions. The fibers are inert and compatible with all fracturing fluids, including ClearFRAC polymer-free frac fluids based on viscoelastic surfactants (VES).

PropNET fibers and proppants are easier to remove than RCP alone, which can cure and bond together inside the wellbore under certain conditions. These specialized fibers do not have temperature, closure-stress or shut-in time limitations before, during or after fracturing. Because PropNET fibers do not bond with proppants, performance is not affected by reservoir depletion, crushing of individual grains or closure-stress cycling from producing and shutting in wells.

When high production rates and maximum proppant-flowback control are required, fibers combined with resin-coated proppant provide reliable proppant-flowback control under a wider range of conditions than either RCP or PropNET fibers alone. PropNET fibers reinforce the RCP to provide additional resistance to rate changes, production cycling and increasing closure stress as reservoirs deplete, especially for extremely high-rate wells. PropNET fibers also improve proppant suspension and transport in wellbore tubulars and dynamic fractures, and reduce frictional pressures during pumping operations as verified by field measurements.

**Saudi Arabia: Fracturing for Sand Control.**

In 1995, Saudi Aramco began developing nonassociated gas reserves in the Ghawar field of Saudi Arabia, including construction of gas-handling facilities (below). The newly built Hawiyah gas plant, with processing capacity of 1.6 billion scf/D [46 million m³/d], required 400 MMscf/D [11.5 million m³/d] of “sweet” gas with no hydrogen sulfide [H₂S] to operate efficiently. Production from wells in the Jauf reservoir, a weak sandstone with bottomhole pressure and temperature of 8750 psi [60 MPa] and 300°F [149°C], was critical in meeting this requirement.

This formation lies at a depth of 13,500 to 14,400 ft [4115 to 4390 m]. Wells produce sweet gas at 10 to 60 MMscf/D [286,000 to 1.7 million m³/d], but it is difficult to maintain solids-free output at these high rates. Excessive sand influx necessitates repeated wellbore cleanouts and causes internal pipeline corrosion by stripping chemical inhibitors off pipe walls.

Conventional sand-control methods were not considered as part of the field-development plan. Gravel-packed screens would restrict production rates and the wells could not have met plant production targets, requiring Saudi Aramco to drill additional wellbores. In addition, TSO fracture stimulations were not always successful because misaligned perforations caused near-wellbore tortuosity, or flow-path restrictions, that increased fracture-initiation and injection pressures. This limited net fracturing pressure and the capability to achieve optimal fracture width, height and length. Standard perforating resulted in unpacked perforations that were pathways for produced sand.

Attempts to control sand with conventional screenless techniques were not successful so a team of Saudi Aramco and Schlumberger experts reevaluated perforating, hydraulic fracturing and proppant-flowback strategies. Using the PowerSTIM well optimization process, these specialists compiled a set of comprehensive formation-evaluation, reservoir-characterization, fracture-stimulation and well-test data to improve stimulation and completion design,
execution and evaluation. This approach helped the team analyze, optimize and implement several innovative practices.

Based on the best available data and up-to-date field responses, the joint completions team developed and calibrated improved petrophysical and formation mechanical-properties models. The new sand-prediction model differentiated the more competent, or stable, layers from those prone to sand production. This improvement helped engineers make decisions about perforating practices and perforation placement.

The Jauf team thoroughly investigated and improved two key aspects of these well completions. First, they developed fracturing techniques using the best combination of oriented perforations, treatment fluids, proppants and flowback-control additives. Second, they implemented screenless techniques, including perforation specifications—interval length, hole size and placement—proppant type and size, and chemical and fluid systems to optimize gas output and minimize sand production.

Screenless methods have been the key to successful gas-well completions in the Jauf reservoir. The objective of producing sand-free gas at economic rates and reasonable drawdown pressures was achieved by multiple means:

- perforating only stable intervals
- perforating one interval per well
- limiting perforated interval length
- using intermediate-strength RCP
- using fiber flowback-control additives
- orienting perforations in the PFP
- forcing fracture closure immediately after treatments
- designing special flowback procedures.

The revised completion strategy avoided perforating within 10 to 20 ft [3 to 6 m] of weak zones as identified on stress profiles. Perforated intervals were limited to single lengths of 30 or 40 ft to ensure fracture coverage of all perforations, create an external pack at the wellbore, and prevent sand flux from untreated perforations.

The combination of intermediate-strength RCP and high-temperature PropNET Gold fibers also was used to stop proppant flowback and help control produced sand. Finally, carefully evaluating and adjusting post-treatment production helped Saudi Aramco achieve and maintain initial sand-free rates.

Perforations properly aligned with the PFP minimize unpacked tunnels that can contribute to sand production. Saudi Aramco chose the Wireline Oriented Perforating Tool (WOPT) and guns with 180° phasing to perforate in the direction of maximum formation stress and PFP orientation at an 80° or 260° azimuth (above).
Oriented perforating reduces treating pressures and creates wider fractures, which also reduce turbulent, or nondarcy, flow and drawdown pressure during production, further mitigating sand production (above).

Fracture stimulations prior to oriented perforating failed to deliver sand-free gas at required rates, but Saudi Aramco observed positive results with the first application of oriented perforating and screenless completions. Analyzing prefracture injectivity and minifracture treatments with DataFRAC fracture data determination services confirmed significant reductions in fracture-initiation pressure for wells with oriented perforations. Pressure losses during pumping operations dropped from about 2000 psi [13.8 MPa] for conventional perforating to less than 600 psi [4.1 MPa] in wells with oriented perforations.

Improved hydraulic fracturing execution and increased well productivity demonstrate the effectiveness of oriented perforating. Fracture stimulation treatments prior to implementation of the revised well-completion strategies that were devised by the joint team resulted in extended flow periods to clean up wells after treatments. In one case, it took 55 days to achieve solids-free production. Optimized screenless technologies and improved fracturing procedures reduced this cleanup period to as little as five days in some cases.

Saudi Aramco routinely limits perforated intervals, and is one of the largest users of oriented perforating services. The company completes most wells in the current Jauf stimulation program with the WOPT system. To date, screenless techniques have achieved sand-free gas rates even at high production rates and after cycling production on and off for several months.

Formation Consolidation

Existing completions and some new wells have perforations that are not oriented in the preferred fracture plane or at optimal 0° or 180° phasing. These “nonaligned” perforations can become a source of sand production, especially at higher rates and drawdown pressures. Formation consolidation, historically by injection of organic resins, addresses this problem by binding individual formation grains together (next page). In combination with TSO fracturing and PropNET fibers, this technique stabilizes a limited collar-shaped volume around wellbores and perforations when resins are evenly diverted across perforated intervals.

Some resins create a high-strength consolidated region while only moderately reducing formation permeability. Using these systems maintains some productivity after consolidation even without fracturing. Other systems impair formation permeability significantly or completely seal off the near-wellbore region. Subsequent TSO treatments extend propped fractures beyond the altered zone to connect with the undamaged formation and control sand production.

Formation consolidation strengthens weakly consolidated formations and minimizes risk of sand influx from nonaligned, potentially untreated perforations. Flowback-control additives in proppant packs prevent sand production from perforations in communication with the hydraulic fracture. The formation around perforations that do not communicate with the fracture is stabilized by the resin and is less likely to produce sand.

In wells with existing conventional gravel packs, consolidation stabilizes gravel in the perforations and in annular packs between screens and casing. This step can enhance or extend well productivity. During TSO fracturing, consolidation techniques also help prevent premature screenouts by limiting treatment-fluid losses into highly permeable existing gravel packs or
the near-wellbore region. The success of these treatments depends strongly on optimized fluid-system chemistry, engineered and controlled fluid placement and wellbore physics.

Schlumberger offers epoxy-based SANDLOCK sand control systems using resin and furan-based K300 systems. Recommended depth of penetration for these systems is 2 to 3 feet [0.6 to 0.9 m] into a formation. These systems rely on multiple stages of injected fluids, which limit effective placement in heterogeneous intervals. Current resin systems are limited to treating intervals of about 20 ft.

SANDLOCK treatments begin with a preflush to clean the formation volume near a wellbore and leave sand-grain surfaces oil-wet and ready to bond with the resin. The resin system is mixed into a water-base carrier fluid, usually linear hydroxyethylcellulose (HEC), and pumped into the rock matrix. The SANDLOCK system has an internal catalyst, and a curing agent is mixed with the resin, so the reaction begins immediately after mixing. Catalyst concentration determines available pumping time. This system has been used successfully for proppant-flowback remedial operations, but has limited application in screenless completions other than gravel-pack remediation because it does not penetrate formations with less than 1-darcy permeability.

The K300 system uses an external catalyst that is pumped after placing resin in the formation to initiate curing. Consequently, treatment procedures are more complicated. Like the SANDLOCK system, a preflush is pumped first, followed by K300 resin; no carrier fluid is used. The next step involves pumping a viscous overflush, usually linear HEC fluid, to sweep excess resin away from the near-wellbore region. In the final stage, an external catalyst is pumped. Unlimited resin-placement time is one advantage of this approach, but uncertainty about effective in-situ downhole mixing of catalyst and resin is a disadvantage.

Formations are fractured during screenless completions, so there is no requirement to use systems that retain formation permeability. This greatly simplifies in-situ consolidation treatments. As a result, Schlumberger employs a novel technique that uses the water-base OrganoSEAL organic crosslinked gel system, which was developed for water-control applications. This single-stage treatment completely fills matrix pore spaces and shuts off near-wellbore permeability. TSO hydraulic fracturing restores well productivity.

The OrganoSEAL-R system can be pumped down wellbore tubulars and diverted with solid agents to treat interval lengths of up to 50 ft [15 m], but coiled tubing is the preferred placement method. This consolidation system costs significantly less, is more environmentally friendly and is easier to clean out of the wellbore than resin systems. OrganoSEAL-R fluids can be easily squeezed into annular gravel packs, but flow less readily into the formation because of differences in gravel and rock-matrix permeability. This makes fluid placement across an entire zone for gravel-pack remediation feasible.

### Formation Consolidation

Chemical consolidation before fracturing stabilizes completion intervals that do not have optimal or oriented perforations (top left). Typically, a resin system is injected into the formation using conventional pumping services or coiled tubing. These treatments consist of three basic stages: pretreatment acid and surfactant preflush to displace formation water and hydrocarbons (top middle), resin injection (top right), catalyst injection and viscous overflush with a shut-in period that allows the resin to cure (bottom left). This procedure is followed by TSO fracturing to bypass the consolidated region and reconnect with the unaltered rock (bottom right).

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Gulf of Mexico: Slimhole Sidetrack

In November 2000, J.M. Huber Corporation assumed operational responsibility for the South Timbalier Block 21 field in the Gulf of Mexico south of Louisiana, USA (above). At that time, the company identified an untapped reservoir compartment and drilled a directional sidetrack from nearby Well 48 to develop updip reserves. Well logs and sidewall cores confirmed 22 ft of oil from measured depth (MD) 11,772 to 11,794 ft [3588 to 3595 m].

The target upper Miocene sandstone was relatively clean with average porosity of 28%, permeability ranging from 100 to 500 mD and a 5800-psi [40-MPa] bottomhole pressure supported by a strong waterdrive. Typically, these Miocene formations require sand-control measures. Based on a history of sand production in the field and a previously completed interval of the same zone in Well 48, completion engineers planned to gravel pack \( \frac{3}{8} \)-in. screens inside a 5-in. liner.

However, during drilling operations, the 5-in. liner became differentially stuck above the planned total depth (TD). This forced the operator to cement the string at 11,101 ft [3384 m] MD as intermediate casing and run a \( \frac{3}{8} \)-in. liner to TD at 12,160 ft [3706 m] MD (next page, left). A smaller conventional gravel pack was not practical because it would restrict production. J.M. Huber and Schlumberger solved this dilemma with screenless technology.

The revised well completion combined optimized perforating, formation consolidation and TSO fracturing with a proppant flowback-control additive with careful control and monitoring of initial cleanup and production rates. Analysis of past screenless procedures and experiences worldwide, particularly unsuccessful completions, confirmed that when any of these techniques or associated guidelines is misapplied, chances of success decrease significantly.

Well 48, originally drilled in the 1960s, could not support a conventional rig intervention from its small caisson structure. For this reason, the operator used a jackup rig to support completion operations, including wireline, coiled tubing and high-pressure pumping equipment. After cement was drilled out of the \( \frac{3}{8} \)-in. liner, the screenless completion was performed in four stages:

- optimized perforating
- coiled tubing acidizing and consolidation
- TSO proppant fracturing with PropNET fibers
- coiled tubing wellbore cleanout.

NODAL production system analysis determined that a 6-ft perforated interval could produce 400 B/D [63.6 m\(^3\)/d] with less than 100 psi [689 kPa] of pressure drawdown at the sandface. Based on SPAN Schlumberger Perforating Analysis modeling software, J.M. Huber and Schlumberger representatives selected charges to create a 0.33-in. [8.4-mm] diameter entrance hole in the casing. This perforating job was designed to achieve the required production rate and prevent sand influx by helping to ensure that the propped fracture would cover the perforations completely.

Perforation density was limited to 6 shots per foot (spf) to improve treatment placement and reduce the likelihood untreated perforations. A phasing of 0° further ensured that perforations would communicate with the propped fracture. The engineering team, however, still worried that proppant flowback might initiate sand production. This dictated the need for a consolidation treatment prior to fracturing. Engineers chose K300 furan resin, which could be placed across the short perforated interval using coiled tubing, to stabilize a volume of formation around the wellbore.

Resins tend to reduce formation permeability to some extent, but hydraulic fractures extend past the consolidated near-wellbore region. Chemical consolidation prevents sand
production early in the life of a well, but by itself may not control sand influx in later stages of reservoir depletion. This soft, or weakly consolidated, formation also required a short, wide propped fracture to control sand by reducing flowing pressure drop and preventing sand influx through perforations. For this job, the operator used a low-guar, borate-crosslinked fracturing system that was compatible with reservoir fluids. A 20/40 mesh, stress-cured, ceramic RCP was selected to avoid crushing of the proppant at the 8000-psi (55-MPa) formation stress. PropNET fibers were added to proppant-laden fluid stages. The TSO fracture treatment, performed from a stimulation vessel, placed 9096 lbm [4126 kg] of proppant in the formation out of a total 13,204 lbm [5989 kg] pumped. Decreasing pump rate at the end of the job avoided excessive surface treating pressures. Controlled flowback immediately after pumping ceased initiated rapid forced closure of the hydraulic fracture. Initially, the well tested at a rate of 535 B/D [85 m³/d] of oil and 4 MMscf/d [114,560 m³/D] of gas with a tubing pressure of 3700 psi [25.5 MPa]. NODAL analysis confirmed a fracture permeability of 200 mD and a slightly negative skin effect. This indicated that the zone was stimulated and would produce better than undamaged formation. After more than a month, hydrocarbon rates stabilized at about 500 B/D [79.5 m³/d] of oil and 2.5 MMscf/D [71,591 m³/D] of gas with a 3500-psi [24.1 MPa] flowing tubing pressure (ftp).

One year after pumping the sand consolidation treatment, this well was still flowing 220 B/D [35 m³/d] of oil, 850 B/D [135 m³/d] of water and 380,000 scf/D [10,882 m³/d] of gas at a 1520-psi [10.5-MPa] ftp. There was no significant sand production during the first year of production.
layers of sand, silt and clay. Pay intervals have low to moderate permeability and historically produce formation solids, which requires sand-control completion methods. Typically, Eni combines several sedimentary groups into “pools” that are completed with conventional gravel packs and produced separately. Some wells have more than 10 distinct pools.

Most wells are dual completions with two parallel strings of 2 3⁄8-in. tubing. A gravel pack cannot be installed for the short string of wells with 7-in. casing, which limits the number of pools that can be completed in a single wellbore (above left). Accessing other pools requires expensive recompletion operations with conventional rigs. In 9%-in. or larger casing, a single, selective gravel pack can be installed for the short string, but full-scale workovers are needed to complete additional intervals.

Without sand control, however, upper zones become choked by sand in a short time, often less than two years. Effective and reliable screenless methods allow completion of multiple layers through the short string without regard to casing size and without bypassing or deferring production of reserves. This approach reduces drilling and completion costs significantly and allows more gas zones in a well to be produced efficiently, even with smaller 6 1⁄8-in. boreholes and 5-in. casing.

Like other developments in this area, the Giovanna field consists of heterogeneous laminated and stratified reservoirs with a gas relative permeability that is low—about 12 mD. These “dirty” sandstones have clay contents as high as 50%. Produced sand and migrating fines cause productivity declines that significantly reduce field output. An upper zone in Giovanna Well 6 was selected for a screenless completion field trial. Eni initially completed this well with dual 2 3⁄8-in. tubing in December 1992, but the wellbore filled with sand in less than two years and had to be shut in (left).

Eni and Schlumberger evaluated each step of the screenless-completion process—perforating, formation consolidation, fracturing for sand control and optimal treatment-fluid selection. Optimized perforating was not an option because the well had existing perforations and a slotted-pipe extension across the target interval. Low permeability limited matrix injection rates and prevented the use of conventional formation-consolidation resins. The remaining option was to remove sand fill from the wellbore and perform a TSO fracture treatment with effective proppant-flowback control.

A relatively low fracture-closure stress—3000 psi [20.7 MPa]—simplified proppant selection, but choosing a mesh size was more difficult. Larger proppant sizes maximize fracture conductivity, but smaller sizes prevent formation particle migration. Wide TSO fractures reduced the likelihood of fines transport by decreasing drawdown pressure and flowing gas velocity in the formation during production. Therefore, a proppant size that could control sand production, but not fines invasion, was chosen.

After comprehensive fracturing studies and simulations, Eni chose a ClearFRAC fluid to meet fracturing objectives. ClearFRAC VES fluids consistently demonstrate superior proppant suspension and transport characteristics, even at low viscosities. Minimizing fracturing-fluid viscosity and optimizing fluid leakoff helped achieve a short and wide TSO fracture in the Giovanna Pool 10 formations, which had not been possible previously with conventional polymer-based fracturing fluids. PropNET fibers were added to keep proppants inside the fracture.

Prior to fracturing, coiled tubing cleanout operations removed sand fill inside and around the perforated extension pipe. A sand plug was placed, or spotted, with the top at 5754 ft [1754 m], leaving 39 ft [12 m] of open perforations for fracturing. Because of platform space limitations, all slurry stages for the fracture treatment were batch-mixed in tanks with independently controlled paddles and recirculating pumps to ensure better fluid mixing and consistency.

This screenless treatment was pumped through the existing completion and performed without a conventional rig. Monitoring net pressure ensured generation of a mature TSO fracture with adequate width. Wellsite observations of surface tanks and treatment lines confirmed that the PropNET fibers helped suspend proppant in the low-viscosity slurry.

A coiled tubing wellbore cleanout was performed and the well placed on production. The
39-ft zone produced gas with no formation sand, fines, proppant or fibers, and at more than twice the initial gas rate and flowing pressure of the original completion. Giovanna Well 6 produced sand- and fines-free for two and a half months.

PropNET fiber effectiveness depends on friction between proppant particles and individual fibers. Proppant size, roundness and surface texture, and fracture closure pressure as well as fiber length contribute to robust, stabilized fractures. In laboratory tests, PropNET fibers create extremely stable packs, even at zero closure stress. This was confirmed in Giovanna Well 6. No proppant was produced from the “stress-free” annular pack behind the perforated extension pipe.

**Offshore Italy: Ongoing Improvements**

Based on the successful rehabilitation of production from Pool 10, Eni immediately scheduled major workovers for this well and two others.

Eni used programmable, continuous blending equipment to perform additional treatments on two zones of the short string in Giovanna Well 20. The zones have not yet been produced because field-development plans call for other intervals to be depleted first. However, the high net pressures achieved during both of these screenless treatments indicated favorable fracture geometries that should prevent sand production.

In nearby Annalisa field, a secondary zone was completed through the short string of a well with dual tubing using screenless methods. Without screenless technology, this interval could not have been completed and produced. The well initially produced at economic gas rates, but sand production occurred before the zone was shut in to open the primary zone. Post-treatment analysis indicated that the TSO fracture did not develop enough width because insufficient net pressure was achieved. A shortage of premixed fluid quantities during the Annalisa field frac pack highlighted the importance of continuous onsite mixing and blending of treatment fluids, proppants and additives for treatment consistency and quality control.

Adequate net-pressure buildup to create optimal fracture geometry is difficult to achieve in soft formations, such as these Adriatic Sea reservoirs. Eni prefers low-viscosity, brine-based fluids for compatibility with Adriatic Sea formations, but their high fluid leakoff characteristics often do not generate the required fracture geometry. Polymer-base fluids, with low fluid leakoff, create fractures that are long and narrow, and may result in excessive vertical fracture height without achieving a TSO.

Using nondamaging ClearFRAC fluids, Eni and Schlumberger tailored fluid characteristics to match reservoir characteristics and optimize fracture geometry. However, even with extremely low fluid viscosities, achieving effective proppant suspension capabilities while maintaining sufficient fluid leakoff is possible only by reducing pump rates at an early stage—often halfway through a treatment. This requires prompt wellsite decisions based on real-time monitoring of net fracturing pressure to achieve optimal TSO fracturing.

Some screenless completions in the Adriatic Sea were considered successful while others had mixed results because of operational rather than technical limitations. All these attempts provided valuable lessons regarding this emerging technology and implementations of novel rigless techniques in future well completions and remedial interventions.

**Offshore Italy: Gravel-Pack Remediation**

Screenless completions provide a cost-effective means of restoring production in gravel-packed completions that fail because the screens are eroded by sand or plugged with fines, hydrocarbon deposits or scale. This method can be implemented without using conventional rigs to pull completion tubulars, equipment and screens. Initial applications targeted gravel packs up to about 50 ft in length and utilized coiled tubing. These remedial treatments are a multistage process, using standard techniques and fluids, such as the OrganoSEAL system, to consolidate annular gravel packs between existing screens and casing before perforating and fracturing (below).

![Image](Image)

^ Gravel-pack repair. Screenless techniques provide alternatives for rehabilitating existing completions that have eroded (left) or plugged (right) screens. Coiled tubing is run to clean out the wellbore, displace produced fluids and place, or spot, a consolidation chemical across and above sand-exclusion screens. These steps are followed by a pressure squeeze to force treatment fluids into the gravel-pack annulus (center). The main objective is to shut off gravel-pack permeability and prevent a wellbore fracture screenout caused by annular fluid loss. Chemical consolidation of the annular pack also keeps perforation tunnels open after reperforating and performing a TSO fracturing treatment. “Micro” cement technology, such as SqueezeCRETE fit-for-purpose slurries, can penetrate and seal off unwanted sections of gravel-packed screens.
Fit-for-purpose SqueezeCRETE cement fluid solutions can shut off unwanted sections of gravel packs that are longer than 50 ft. These specially engineered cement slurries penetrate farther into proppant packs than other “micro” cements without bridging or dehydrating during placement. This technique helps avoid excess loss of treatment fluid and premature screenout in existing gravel packs.23

Jetting across a treated interval using coiled tubing tools with fluid nozzles on a rotating head removes consolidation chemicals from inside the screens. No attempt is made to remove the consolidation system from gravel behind the screens. Wells then are recompleted with optimal perforations using deep-penetrating charges to provide sufficient penetration into the formation and large enough entry holes in casing to facilitate fracturing success. After reperforating, the screen and consolidated gravel pack are stimulated with a TSO fracture treatment that includes proppant-flowback control additives.

Because of the Giovanna field screenless successes, Eni recognizes rigless application of screenless methods as a practical alternative to rehabilitate wells once believed to require conventional rig interventions. Rigless techniques also allow recompletion of wells with gravel-packed screens that fail or plug. Giovanna Well 14 was the first candidate well for screenless rehabilitation of failed screens without pulling and replacing the completion equipment.

Downhole conditions, reservoir compaction, and a long completion interval presented operational challenges. The lower section of screen and gravel pack was shut off with a SqueezeCRETE cement slurry to reduce the target interval below 30 ft. In addition, the reperforated interval allowed coiled tubing access to just the first 12 ft [3.7 m], so the TSO fracture probably did not cover all of the perforations, which resulted in early fines migration.

Another screenless completion was identified and scheduled for an uncompleted interval in Giovanna Well 16, but reservoir compaction buckled the production equipment and made reentry impossible. Several additional screenless completions are planned in other fields where the dilemma facing completion teams is that remaining gas reserves in target layers are insufficient to justify the expense and risk of conventional rig operations. Dual-well completions were equipped with a sliding side door (SSD) at one or more perforated intervals within their short or long production strings. Before screenless completions were performed under these conditions, surface tests were used to verify the feasibility of fracturing through an SSD. Full-scale yard tests assessed potential erosion and pressure integrity of the SSD after pumping significant volumes of proppant-laden fluid under field conditions.

These surface tests were performed in four stages with pressure tests and visual inspections conducted after every stage. After pumping 87,000 lbm [39,462 kg] of proppant at concentrations up to 12 pounds of proppant added (ppa), the SSD valve was tested to 3000 psi [20.7 MPa]. Visual inspection confirmed only minor superficial erosion effects, verifying that large volumes of proppant-laden fluid can be pumped through an SSD valve without jeopardizing its pressure integrity and without significant erosion. Subsequently, SSD devices installed downhole have been closed, successfully pressure tested and reopened following screenless treatments in several Adriatic Sea wells.


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Coiled tubing-conveyed fracturing. CoilFRAC stimulation through coiled tubing service facilitates formation consolidation and hydraulic fracturing of individual or multiple zones in a single operation. A tension-set coiled tubing packer and sand plugs can be used for zonal isolation. Pumping schedules for each zone include extra proppant to spot a plug across fractured intervals before moving up to treat the next zone (left). The CoilFRAC ST straddle tool system seals above and below target intervals to isolate individual zones for selective stimulation. The tool can be moved quickly from one zone to another without pulling out of the well (right).
Selective Treatments
In addition to proppant-flowback control, the success of screenless completions relies heavily on effective placement of stimulation fluids and complete fracture coverage across all open perforations. With coiled tubing as the conduit for proppant-laden fracturing fluids, multiple pay zones can be treated consecutively during a single mobilization (previous page). The CoilFRAC stimulation through tubing service using a CoilFRAC ST straddle tool system selectively isolates individual intervals to achieve optimal fracture width and conductivity without conventional drilling-or workover-rig intervention.

Screenless completions offer a viable alternative when conventional sand-control methods are economically unattractive or cannot be applied. This approach allows production from zones that previously could not be completed. Screenless techniques are straightforward and can be reapplied later in the productive life of a well if the need arises. Increasingly, operators recognize this technology as an enabling well-completion strategy for both well completions and production rehabilitation.

Sand-Management Solutions
Operational problems associated with sand influx adversely affect well and reservoir productivity, jeopardize wellbore longevity, limit remedial-intervention options and impact field profitability adversely. Ensuring that perforation tunnels and the surrounding formation remain stable is an important element of sand-management efforts (above).

Selecting screenless candidates, therefore, is an important aspect of well-completion planning and execution that requires careful formation evaluation and characterization using the highest quality production data as input to sand-prediction models, fracture-design programs and reservoir simulators. SandCADE software and other mechanical models establish maximum critical drawdown pressures and flow rates to avoid proppant flowback during cleanup and production phases.

Currently, wells that benefit most from screenless methods are those with configurations that make installation of internal completion assemblies difficult, undesirable or even impossible. However, applications for rigless techniques will increasingly involve recompletion of wells to tap marginal reserves that do not economically justify conventional rig-based operations. Screenless results to date clearly prove the viability of this emerging technology, which provides attractive solutions to avoid otherwise deferred production and lost reserves.

Screenless techniques are an important element in advanced sand-management strategies, but they will not replace conventional sand-control methods. In some reservoirs, however, they provide cost-effective alternative strategies to eliminate or manage sand production over the productive life of a well or field development. Current research and development efforts are directed at improving computer models for predicting sand production and providing enhanced risk assessment. These efforts will ensure the effectiveness of increasingly sophisticated well perforating and completion techniques. —MET