Regaining Sand Control

Sand-prone reservoirs contain a growing percentage of the world’s hydrocarbon reserves. Many of the wells tapping into these resources are producing significantly beyond their original life expectancy, which can result in weakened formations. Consequently, operators are increasingly seeking cost-effective methods for repairing failed systems or for adding new sand control systems where none existed previously.

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In weakly consolidated formations, fluids production is nearly always accompanied by sand. This can lead to reduced recovery rates, damage to surface and downhole equipment and elevated maintenance costs. The result of a two-stage process, sand production is initiated by stresses acting on formation rock to cause shear failure. Produced fluids then carry the spalled sand to the wellbore from which it flows to the surface or becomes deposited elsewhere within the well system. Phase change, particularly water breakthrough, has also been associated with sand migration.

Numerous explanations have been offered about the exact relationship between water breakthrough and formation failure. One holds that since most sandstone reservoirs are water-wet, water breakthrough results in decreased capillary pressure due to increased wetting phase saturation (see “Fundamentals of Wettability,” page 44). Because capillary pressure tends to hold the grains together, water breakthrough facilitates sand production. In essence, low water saturation equates to high capillary pressure, high water saturation equates to low capillary pressure, and no water equates to no capillary pressure because then only a single liquid phase exists.

Another theory holds that as water breaks through the formation, it reduces the relative permeability of oil and water. Operators react by increasing drawdown to maintain hydrocarbon production, thus initiating fines movement. The water also increases the viscosity of produced fluids and creates a higher drag rate across the sand grains, pulling fines through the formation. In the end, most experts agree the connection between water breakthrough and sand production is poorly understood and is likely the result of several factors.

With onset of formation failure and evidence of mobilized sand (or solids particulates) through the formation, operators can opt to reduce flow to rates incapable of carrying solids, manage produced sand, or create a barrier, in essence a filter, to prevent sand movement from formation to wellbore. Stopping, or at least slowing, the flow of sand, while minimally impacting production, requires the operator to choose from among such mechanical exclusion techniques as cased-hole gravel packs, high-rate water packs, frac packs, openhole gravel packs or stand-alone screens. Additionally, screenless completions offer a chemical option applicable in moderately weak reservoirs. This technique uses resin-coated proppant to stabilize the near-wellbore region, while leaving enough of the original permeability in place to allow production of the formation and fluids.

Sand management solutions that may have been appropriate at the time of the well’s construction may fail with time and changing downhole conditions. Openhole horizontal completions offer a case in point. By virtue of their design, risk of sand failure in many of these wells is extremely low during initial production but increases to around 50% near abandonment pressures.

How an operator responds to the onset of sand production is almost always a function of economics. When a highly prolific zone produces sand early, for example, a recompletion or sidetrack may be justified. In the case of a well nearing its economic limit, it may be just as effective to do nothing and simply recover any possible remaining reserves before the wellbore fills with sand and stops flowing. Between these extremes, engineers must strike a balance between sound economics and what is technologically possible. The value gained must be weighed against the cost of the operation and, in many instances, deciding whether and how to pursue remediation is also informed by mechanical realities such as the existing well profile, available technology, the failure mechanism and geographic location.

Within this article, sand control remediation refers to sand production problems that occur after a period of oil and gas production. We describe sand control remediation options and tools—such as through-tubing gravel packs, screen patches, screen cleansouts, expandable sand screens and placement of new screens inside failed ones—along with the decision-making process that leads to them. Through case histories, we investigate specific remedies and their outcomes. Recompletions and large-bore sidetracks will not be considered as these can include primary sand control methods.
relatively minor and might never have created a problem over the term of the well's original life expectancy, may compromise the system during extended service time. Or the screens may no longer be suited to an unforeseen solids production rate or particle size (above left).

The most common point of failure in sand control systems is at the screen designed to constrain the gravel or, in the case of screen-only completions, at the formation. Screens typically fail as the result of productivity or completion activities. Failure causes can be grouped in the following categories:

- destabilized annular gravel pack due to excessive flow velocity through the perforations
- screen erosion
- screen corrosion
- localized hot spots caused by flow around sections of plugged screens or by inadequate annular gravel packing
- screen collapse from compaction
- screen collapse caused by plugging.

These mechanisms often work in concert to cause final system failure. This is particularly true in the case of interplay between destabilized annular packs, screen erosion and corrosion. In this scenario, as the gravel packed into the...
Sand control screen failures can be divided into five categories including design failure, application failure, early-time failure, production failure and subsidence failure (below). Design failure reflects the difficulty of matching a sand control system to a particular producing horizon. Successful frac packs and openhole gravel packs, for instance, require extensive knowledge of such parameters as formation permeability, frac-pack gel-breaking chemistry, and fracture progression and initiation.

Application failure is a function of operational problems during system installation that cause the job to be prematurely terminated. These malfunctions may be the result of poor planning or a calculated risk such as forgoing redundancy based on previous experience. Design and application failures in frac-pack and openhole gravel-pack systems are commonly the result of insufficient or poor-quality data. Once these complex systems have been in place and performing properly for a period of time, however, they have proved to be the most reliable of available sand control options.

Early-time failures, defined as those that occur within 30 days of startup, generally can be traced to either a design or application failure not initially recognized as such. Failures occurring after that time are production failures usually resulting from problems related to plugging or hot spots. Sand control failures caused by subsidence are sometimes the result of poor reservoir understanding but, in other cases, are expected by operators who maintain a drilling unit or coiled tubing unit on location and plan to redrill pay zones every 6 to 30 months.

Historically, tracking such data has been difficult and only recently has a sufficient number of cases been documented to allow reliable conclusions. However, time and experience are having their expected effect, as are the benefits of such advances as downhole gauges that enable engineers to evaluate jobs in real time as they are being performed.

### Analysis of Failure

Corrosion begins independently and, in time, can cause failure even in the absence of a destabilized pack. Corrosion is a particular threat in screens placed along high-angle and horizontal sections. The acid, which is used in conjunction with gravel-pack treatments, migrates to low spots in the hole and remains there for the life of the well. Most often, corrosion arises from a poor choice of screen material, such as austenitic alloys, which are susceptible to pitting, crevice-cracking and stress-related corrosion cracking in the presence of chloride and oxygen. Corrosion can also result from improper cleanup or ineffective mud removal following initial installation (previous page, bottom right).


4. Austenitic alloys are stainless steels containing chromium and nickel and sometimes manganese and nitrogen. They are structured around the Type 302 composition of iron, 18% chromium and 8% nickel and are generally resistant to corrosion and pitting except in certain chemical environments.
A somewhat different screen-failure mechanism is due to increased flow velocity focused on a small area when fine particles plug screens. When large sections of the screen become plugged, flow is funneled to a few remaining open spots that have formed pathways of least resistance. This funnelling action works to significantly increase flow velocity, creating what the industry terms localized hot spots. These hot spots can also arise from poorly placed gravel packs that leave voids that, much like a destabilized gravel pack, become flow paths through which sand-laden fluid is directed to a small section of screen. Voids in gravel packs have been seen even when the volume of sand pumped into the annulus and perforation tunnels during gravel-pack operations equaled, or even exceeded, the calculated space to be filled. The discrepancy is usually attributable to washouts along the wellbore that add annular volume not accounted for in original calculations.

Another screen-failure mechanism occurs when screens become plugged along their entire length, but rather than create hot spots, develop sufficiently high pressure-induced loads to cause them to collapse (right). Collapse can also occur as a result of wellbore compaction.1 In the former case, the problem often stems from poor screen and gravel-pack sizing that allows fines to migrate through the gravel pack and become trapped in the screen. Both cases may result from poor reservoir understanding, although compaction and ensuing collapse are sometimes accounted for in the well plan. Even when pressures are insufficient to cause collapse, the well may still suffer untenable production losses as the screens become impermeable and must be either pulled or cleaned in situ.2

Sand control system life, to date, appears to be a function of type. Screen-only completions, for instance, exhibit a tendency to accelerated failure rates in two to three years. Cased-hole gravel packs do the same in about six to eight years. Openhole gravel packs (OHGP) and frac packs (FP) historically have resisted that trend and, once early failures are culled from the data, they appear to last the well’s lifetime.

A possible explanation for this anomaly is that OHGP and FP systems have been in widespread use only a short time and may yet have a time-related shift to higher failure rates sometime in the future. Additionally, unlike the other two systems, openhole gravel packs and frac packs are deployed using high pressure that forces gravel into the voids of the near wellbore. This pressure probably works to shut off flow from high-permeability streaks that might otherwise lead to nozzle effects responsible for the failure of many screens. Frac packs have also traditionally been a Gulf of Mexico practice. That may skew the data as the systems are used to fracture across barriers and so commingle production from numerous sandstones. This spreads the flow of high-permeability streaks across a wider section of the pack, creating less flux loading on the screen. And finally, it is a common practice in the Gulf of Mexico to drain zones quickly and move on to others; because of this, screens may be removed from service before application or design problems cause them to fail.

Washing Troubles Away

In recent years, pressured by the high cost and tightening supply of offshore rigs and a proliferation of subsea wells, operators have become eager to find rigless intervention methods to deal with screens plugged by fines migration. One service-industry response has been through-tubing, chemical-based solutions derived from those used to treat scale buildup on production tubing.

Production from Shell’s Bijupira field in the Campos basin is the first by an international operator offshore Brazil. Since first oil in August 2003, the field had reached a production plateau of about 50,000 bbl/d [8,000 m³/d] by 2004 before declining to around 15,000 bbl/d [2,400 m³/d] less than two years later. This rapid falloff was attributed to increasing water cut and declining production rates. The bulk of the field’s production comes from three of the field’s seven production wells, Q, T and S, all of which produced nearly dry oil with water cuts of less

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6. Fines can include different materials such as clays (phylosilicates smaller than 4 microns) and silts (silicates or aluminosilicates with sizes ranging from 4 to 64 microns). Kaolinite and illite are the most common migrating clays. Fines migration causes particles suspended in the produced fluid to bridge the pore throats near the wellbore, reducing well productivity.


Acock et al, reference 1.


8. Injected fluids tend to follow the path of least resistance, often resulting in the least permeable areas receiving inadequate treatment. By using either mechanical or chemical means of diversion, the treatment can be focused on the areas requiring the most treatment.

9. When acid is bullheaded into the formation, it may dissolve the fines blockage it first encounters and by doing so create a flowpath for the remaining acid into the formation. Consequently, the remaining acid would flow into the first zone and not reach the remaining affected areas.
than 10%. The combined production from those three wells had fallen from a peak of 40,000 bbl/d [6,400 m³/d] to 8,000 bbl/d [1,300 m³/d]. Declines on Q and T were gradual and constant over time, at exponential rates of 60% per year. The decline on S happened suddenly during a routine scale-inhibition bullhead squeeze using procedures and chemicals that had proved successful on other wells in the field.

By the end of 2004, routine well surveillance confirmed these declines were not the result of pressure depletion due to compartmentalization. Instead, analysis by Shell and Schlumberger engineers revealed that the wells were impaired. After considering numerous possibilities, the engineers concluded that the most likely cause was formation fines migrating through poorly sized gravel of the more than 600-m [2,000-ft] long gravel packs, plugging the screens. Although scaling was considered a secondary, considerably less likely cause, the decision was made to treat for both possibilities in a two-phased approach. The wells were to be first treated with a coiled tubing-conveyed barium sulfate [BaSO₄] scale dissolver, followed by acid stimulation to remove fines from the gravel-pack screens and near-wellbore gravel pack.

A testing program was conducted to ensure the chemicals and acid would not harm the formation, materials in the completion, or the topsides of the floating production storage and offloading (FPSO) vessel to which the wells connect. Although the configuration also ensures that energy is imparted to the fluid at the injection point so that acid reaches the lower parts of the open hole. Use of coiled tubing alters the relative contact time of acid on separate zones and so addresses the complex relationship between the rate of change of the skin factor in each zone and the distribution of acid in the wellbore.¹

Engineers recognized that a possible drawback to the use of coiled tubing in this case is pump-rate limitation, particularly as treatment depth of penetration is essentially a function of injection rate. Jet Advisor scale removal software simulated best pressures and rates to optimize flow and pressure effectiveness, along with a constant jetting-nozzle rotation (below). In addition, CoilCADE coiled tubing design and

Jet Advisor software. After selecting a coiled-tubing size, the engineer inputs well and fluid data to be used by Jet Advisor software to calculate the maximum pump rate through it and thus the maximum possible annular velocity. The pump rate will also indicate the nozzle pressure drop based on each nozzle size. The Jet Blaster tool will require a minimum of 1,500 psi [10.3 MPa] across the nozzle to rotate the head. Based on the above data, the Jet Advisor software will select one of the four standard nozzle sizes and nozzle heads to maximize ROP and nozzle horsepower given user specifications. Nozzle performance varies with specific bottomhole conditions (left), and nozzle selection is based on developing the highest possible jetting power in the existing wellbore environment. Pressure drop across coiled tubing, jetting nozzles, BHA and annulus (right) is used to help select proper jetting nozzles, coiled tubing size and fluid to be pumped.
A two-pronged approach in three wells in Brazil. Decreased wellhead pressure (WHP) during and immediately following scale and acid treatments indicates successful removal of fines that had been plugging sand screens in each of three wells in the Bijupira field, offshore Brazil.

Evaluation software was used to check coiled tubing forces and stresses and wellbore hydraulic dynamics. Virtual Lab geochemical simulation software evaluated possible damage to the formation from secondary and tertiary reactions between all products involved. The acid was continuously mixed by batches and no liquid hydrofluoric acid [HF] was handled as it would be generated by the reaction between hydrochloric acid [HCl] and ammonium bifluoride [NH$_4$F$_2$].

Each well first received scale-dissolver treatments that reduced wellhead pressures. Acid stimulations began once the scale dissolvers were flowed back to the FPSO. When the first-stage formic acid made contact with the formation, wellhead pressures decreased to 50 psi [0.344 MPa] in Well Q, and to 0 psi in the other two wells. The wellhead pressure in Well Q dropped to 0 psi during the main treatment before dipping below hydrostatic pressure (above).

After cleanup, testing determined that productivity on all three wells increased by a factor of about 10. Before treatment the wells produced through artificial lift and drawdowns of about 2,000 psi [14 MPa]. Afterwards they all flowed naturally with drawdowns of 300 to 400 psi [2 to 3 MPa]. The initial plan was to limit the risk of fines migration by limiting drawdown and keeping production at about 6,000 bbl/d [950 m$^3$/d] per well. The three wells were brought on line at a cumulative 17,460 bbl/d [2,780 m$^3$/d] of oil. After several months of unchanged conditions, however, Shell began to increase flow rate, and by October 2006, production from the S well was up to about 7,000 bbl/d [110 m$^3$/d], with similar increases in Wells T and Q in the following months. By March 2007, Wells T and S were producing about 8,000 bbl/d, and the Q well held steady at 6,000 bbl/d. By May 2007, the treatments had resulted in the addition of 2 million bbl [318,000 m$^3$] of incremental oil, while skin-factor tests confirmed no indication of fines migration.

**Salvage Operations**

Resins and proppant-flowback control, in conjunction with screenless completions, have also been deployed to manage sand-prone formations. Screenless completions require an integrated approach involving reservoir characterization, perforating, coiled tubing intervention, matrix acidizing, resin consolidation, optimized fracturing with proppant-flowback control and fines-migration prevention. A primary attraction of these screenless completions is that they can be deployed as through-tubing systems without the cost of a rig. They exhibit lower skin factors than conventional gravel-packing techniques and do not restrict wellbore access. In maturing fields, screenless systems are especially well-suited for initial completions for their economy and their ability to stop fines migration without sacrificing production.

These same attributes make screenless completions appropriate for reentering wells to capture reserves left behind pipe in sand-prone formations. Their attraction is enhanced when those reserves are too small to justify the expense of a drilling rig. For example, upon discovering its 40/60 gravel-pack sand screen in a well in the Adriatic Sea was nearly completely plugged by fines, Eni opted to first seal the existing completion and then reperforate the screen using wireline guns. The interval was then fractured with a tip-screenout (TSO) design, and a through-tubing screen was placed across the perforated section. A surface-modifying agent helped prevent fines migration and plugging of the gravel pack. A second well in the same field failed when the action of produced sand and proppant eroded through a screen of a frac-pack completion. The well was refractured through the hole in the screen, and a resin was applied to the proppant to lock it into place, thus repairing the damaged screen without restricting the flow area.

Recently, Chevron leveraged Schlumberger-provided screenless completions to greatly increase return on its investment in a series of six wells in a mature Gulf of Mexico field. In each of the wells, the techniques included optimized perforation phasing and size, near-wellbore consolidation, tip screenout and fines management to capture behind-pipe reserves (next page). The team used K300 furan resin sand consolidation systems on all six wells and, heeding lessons learned on the third well, fines inhibitor on the final three.

<table>
<thead>
<tr>
<th>Well name</th>
<th>Pretreatment WHP</th>
<th>Postscale WHP</th>
<th>Postacid WHP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Q</td>
<td>1,100 psi [7.6 MPa]</td>
<td>760 psi [5.2 MPa]</td>
<td>0 psi</td>
</tr>
<tr>
<td>S</td>
<td>560 psi [3.8 MPa]</td>
<td>5 psi [0.03 MPa]</td>
<td>0 psi</td>
</tr>
<tr>
<td>T</td>
<td>410 psi [2.8 MPa]</td>
<td>11 psi [0.076 MPa]</td>
<td>0 psi</td>
</tr>
</tbody>
</table>

11. Damage created by fines usually is located within a radius of 3 to 5 ft (1 to 1.5 m) of the wellbore, but can also occur in gravel-pack completions. In sandstone formations, hydrofluoric acid [HF] mixtures are used to dissolve fines. In carbonate formations, the goal is not to dissolve but rather to disperse fines in the wormholes, so hydrochloric [HCl] acid is used as the treatment fluid.
15. In fracturing high-permeability formations, wide and high fractures are preferable to those extending great distances from the wellbore. Such a configuration is achieved through tip screenout (TSO) once the fracture has opened the desired distance from the wellbore. TSO is achieved by allowing leakoff of the fracturing fluid into the formation to the point where there is insufficient fluid to suspend the associated proppant.
Of the six completions, Wells A, B, C and F are in a field that has been on line since the 1960s. While beyond peak-production levels, they still contained several small formations of limited reserves, all of which needed sand control. To justify completing these untapped zones, it was essential that they be completed as economically as possible without sacrificing productivity. A fifth well, D, was completed in a depleted reservoir that included four natural completions—without sand control. The sixth, E, was also completed in a depleted reservoir with two previous completions—a gravel pack and a lower, naturally completed zone.7

Project engineers used PIPESIM production system analysis software to conduct nodal analysis on each well and to model its reservoir and completion to determine production rates for a given drawdown pressure. The PIPESIM model is populated with reservoir properties from well logs, production history and reservoir permeability data calculated from pressure responses recorded during fracture stimulation. Engineers then applied drawdown-limitation guidelines for screenless completions, based on experience and known limitations of the fiber proppant-flowback-control additive, to avoid proppant flowback and sand production. Following production startup, the team closely monitored rates and pressures and compared them with the nodal analysis, not only to ensure that drawdown pressure did not exceed the guideline limit, but also to quantify the completion performance by calculating total skin factor.

In wells with a long production history, ProCADE well analysis software was used to match that history with a material-balance model to determine reservoir parameters such as permeability, total skin factor and reservoir size. ProCADE software not only evaluates completions performance, but can also be applied in the candidate-recognition phase to estimate remaining reserves and so determine if a screenless completion is economic. It allows planners to use production history-matching plus nodal analysis to see if the target production rates can be achieved within the drawdown limitation.

Well A has four zones that are still productive but require sand control. The intervals are separated by a total of only 200 ft [60 m]. This small separation would typically require that the operator use completion equipment employing screens that would, in turn, force the use of rig-based workovers to pull and rerun the screens in the course of future recompletions. A screenless completion was planned that included perforating the zone of interest, injecting sand-consolidation resin, fracturing with fiber proppant-flowback control and washing proppant from the wellbore using coiled tubing. The interval was perforated to achieve optimal productivity with the fracturing treatment while ensuring that all perforation tunnels were treated. The formation was consolidated, and the fracture treatment was designed for TSO with sufficient conductivity contrast between the fracture and formation to reduce drawdown to a minimum. A resin-coated proppant with a fiber proppant-flowback-control additive was used to stabilize the proppant in the fracture without mechanical devices such as screens.

The operator was anticipating a production rate of 200 bbl/d [32 m3/d], but after treatment the well produced 500 bbl/d [80 m3/d] of oil and 2.5 MMcf/d [70,800 m3/d] of gas. Sand from a lower zone left behind pipe forced the well to be shut in 18 months after initial production. The event confirmed that no sand or proppant was being produced from the screenless completion. The well was put back on production following a coiled tubing gravel-pack installation across the offending lower zone.

The economic driver for Well B was limited gas reserves. The original completion on this well did not include sand control. However, when the natural completion produced sand, the well was choked back and could no longer meet its targeted gas production rate of 1 MMcf/d [28,300 m3/d]. The goal for Schlumberger engineers was twofold: control sand and increase production. Sand was cleaned from the well before a mix of matrix acid and consolidation fluid was injected into the formation using coiled tubing. The well was fractured using resin-coated proppant and fibers before the excess fracture slurry was washed out. The results were an end to sand production and gas rates that reached 3.2 MMcf/d [90,600 m3/d] at 1,100 psi [7.6 MPa] flowing tubing pressure, a fourfold increase over its rate of 800 Mcf/d [23,000 m3/d] prior to treatment.
The target in Well C was a bypassed pay zone. The existing completion configuration—a gravel pack below the zone of interest—did not allow a traditional sand control method without first mobilizing a rig to pull the original completion. As a matter of economics, after first perforating the casing with the tubing in place, the options were to then deploy either a through-tubing screen and gravel pack or a through-tubing screenless system. The latter was chosen and installed in much the same manner as the two earlier wells.

Following the workover, the well produced sand-free at 600 bbl/d [95 m³/d] of oil, 200 bbl/d more than expected before the job, and 3.5 MMcfd [99,100 m³/d] of gas with a post-stimulation skin factor of 0.5. Two months later, however, the well began to produce very fine-grained solids through the proppant pack. The operator performed a fines-control treatment and installed a vent screen. Production decreased to 350 bbl/d [56 m³/d] of oil and 1 MMcfd [280 m³/d] of fluid with 80% water cut.

That decision, in turn, narrowed sand control options to either a screenless or a through-tubing vent-screen completion. However, since a vent-screen system would create additional pressure drops, increase operational complexity and limit future workover options, a screenless completion was selected. The procedure differed from previous wells in the series in that existing perforations were used, and fines control was included in the design. Put back on production immediately following the treatment, the well exceeded targets with rates of 50 bbl/d [8 m³/d] of oil, 130 Mcf/d [3,700 m³/d] of gas and 516 bbl/d [82 m³/d] of water.

Wells E and F were also successful screenless completions. The zone of interest in Well E had not been produced before and so optimal perforating and fluid-placement practices were applied. With a target production of 250 bbl/d [40 m³/d], it too outperformed initial expectations by initially producing 367 bbl/d [58 m³/d] of oil, 306 Mcf/d [8,665 m³/d] of gas and 245 bbl/d [39 m³/d] of water.

Well F, located in the same mature field as A, B and C, is the first screenless completion behind both tubing and casing between two existing production packers and two depleted gravel-pack completions. Wells E and F were also successful screenless completions. The zone of interest in Well E had not been produced before and so optimal perforating and fluid-placement practices were applied. With a target production of 250 bbl/d [40 m³/d], it too outperformed initial expectations by initially producing 367 bbl/d [58 m³/d] of oil, 306 Mcf/d [8,665 m³/d] of gas and 245 bbl/d [39 m³/d] of water.

In all six cases, the lowest risk option for sand control was a conventional gravel pack or frac pack. But the economics of these wells, particularly those with questionable or limited remaining reserves, did not support the cost of a rig. Beyond abandonment, traditional alternatives included perforating without sand control, perforating with chemical consolidation and installing a stand-alone screen, through-tubing gravel pack, through-tubing screen with gravel pack or through-tubing screen with frac pack. All have economic benefits over rig-based solutions but also have drawbacks, such as requiring the use of a rig for future workovers, or production compromises through restricted flow areas. Screenless solutions used for properly selected candidate wells, on the other hand, offer an alternative that includes production optimization and sand control.

Expandable sand screens (ESS) are a relatively new sand management product. They are attractive in openhole completions applications for their ease of installation and, since they use no filter medium, result in a low skin factor. These characteristics make ESS an effective means for controlling sand production in the Niungo field onshore Gabon. The highly unconsolidated sandstone reservoir, with permeability ranging from 0.5 to 2 darcies, requires sand control. The 31°API, paraffinic crude is accompanied by 250 ppm H₂S. Initial reservoir pressure was 1,091 psi [7.5 MPa] with 109°F [43°C] bottomhole temperature and a gas/oil ratio of 200 Mcf/bbl [36 million m³/m³].

Operator Perenco completed the first of three wells in the prospect with a cased-hole gravel pack. The second phase of development consisted of 23 wells using openhole expandable sand screens with 230-micron premium mesh. The third phase of development, completed more recently, used openhole gravel packs and stand-alone screens. For the upper completions, Niungo wells require artificial lift. Electrical submersible pumps (ESPs) and a few progressing cavity pumps (PCPs) are installed in most wells in the field.

Following the second development phase, several ESS wells experienced low pump run life. Analysis indicated the major causes to be high sand production, gas lock, electrical failures and ESP failures. Produced sand taken at 806 m [2,644 ft] with a sand bailer was too large to have passed through a 230-micron weave, and what was visible on the microscope was clearly not contamination (below left). Clearly, active sand control had failed, but the cause was uncertain.

During its first two years of production, seven workovers were performed on the Niungo-26 well, including switching from an ESP to a PCP. However, the problems of erratic production, gas locking and sand production continued, so the operator decided to include remedial sand control prior to rerunning a new pump. Since the smallest ID of the ESS was 4.880 in., the decision was made to order two remedial screen sizes, 2⅛ in. (3.6 in. maximum OD) and 3⅜ in. (4.25 in. maximum OD). A MeshRite stainless-steel screen in screen in Screen

Screen was selected because it would maintain the ESS hole integrity and would retain the biggest particles that might enter the failed ESS creating a natural pack inside it. The workover was performed with a Perenco-owned snubbing unit and because the oil in the Niungo-26 well is paraffinic, it was first cleaned using hot water and viscous gel through coiled tubing.

Using 1¼-in. coiled tubing, the well was cleaned with 80°C [176°F] water containing 2% potassium chloride [KCl]. An obstruction was encountered at 814 m [2,670 ft] and nitrogen and gel were added to progress to bottom. Then, 2⅛-in. remedial liner screens could be set only at 827 m [2,713 ft] measured depth inside the ESS. The ESS top was at 816 m [2,677 ft] and its bottom at 837 m [2,746 ft], which could have been a result of ESS damage.

Following the MeshRite installation, the well was slowly put on production according to the supplier’s recommendation and eventually came on line at rates equal to its initial production with no sand. In the next six months, the well delivered production equal to that of the first 18 months of its life.

Future Remediation

Active sand control remediation has been gaining increased attention within the industry. Significant crude-oil and gas price increases, combined with reduced access to large new finds, have added a sense of both urgency and potential value to remaining reserves in aging fields. Anxious to avoid the risks and high costs associated with adding reserves through technologically difficult and expensive plays in deep water and other remote environments, operators find remediation of existing assets particularly attractive. As a consequence, companies that once sought to sell off maturing properties rather than dedicate resources to rehabilitating them, today may view stranded reserves in sand-prone reservoirs as a major source of reserve growth.

Interest in sand management has been further fueled by reports from major operators who indicate their reserves from sand-prone reservoirs have increased significantly. Just a few years ago, for example, about one third of BP’s production came from sand-prone reservoirs. By the end of this decade, however, such formations are expected to account for nearly half of all BP’s production.¹¹ The company considers the situation sufficiently important to have recently established a technology leadership area (TLA), “Beyond Sand Control,” to globally organize the sand management of its assets.

Recent data suggest that the introduction of real-time monitoring during system installation, likely available within the next few years, coupled with growing industry experience in sand control design and application, will substantially reduce failures. The logical next step would be sand control systems equipped with production monitoring capabilities to warn operators of particle movement at the sandface or of the onset of plugging and hot spots. Such real-time data could also be used to increase knowledge about the effects of production on formations and so aid in the creation of services and practices that may significantly extend well life.

¹¹ The company considers

—RvF