Practical Approaches to Sand Management

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Sand production is a serious problem in many oil and gas assets worldwide. It can drastically affect production rates; it can damage downhole and subsea equipment and surface facilities, increasing the risk of catastrophic failure; and it costs producers tens of billions of dollars annually. Sand management is a complicated issue that cannot be addressed by a one-size-fits-all approach. Instead, operators have embraced a multifaceted approach, exploiting the vast array of technologies and expertise available to manage this problem.

Failure at the sand-grain scale during hydrocarbon exploitation can cause wellbore-stability problems, casing collapse, reduced production, and in extreme cases, the loss of a wellbore.[1] Loose sand grains are mobilized at certain pressure-drawdown levels, fluid velocities and fluid viscosities; once produced into the wellbore, these particles can create havoc downstream.

Produced in fast-flowing conditions or great numbers, sand grains erode tubulars and can become stationary or migrating obstructions. The erosive capability of produced sand depends on many factors, including the amount of sand being produced, sand-particle velocity and impact angle.[2] Erosion from sand production—sanding—damages downhole tubulars, subsea hardware, pipelines and other facilities, possibly causing catastrophic well failure and harm to personnel and to the environment.

Sand accumulations can choke off production anywhere along the flowline, reducing production revenues and costing significant amounts of time and money to clean out. Remedial operations on subsea wells and fields are particularly expensive. Produced sand that reaches production facilities must be separated from produced

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fluids and disposed of. Although the exact cost is difficult to quantify, experts agree that produced sand costs the oil and gas industry tens of billions of dollars annually.

Sand production has always been a problem, but the manner in which the exploration and production (E&P) industry manages this problem has become more sophisticated. This article briefly reviews the basic principles of sand production and the technologies available to help predict, prevent and monitor sand production. Case studies show that sand management is best achieved when operators understand sand-production mechanisms within the reservoir and use an informed decision-making process to select the appropriate technologies and methods for addressing the problem.

The Nature of Sand Production

Understanding why reservoirs produce sand is the crucial first step toward managing sand production. The installation of downhole completion hardware may represent an important part of the solution, but greater knowledge engenders a more thorough and longer-lasting solution. For example, the ability to model and predict the sand-production tendencies of a reservoir allows engineers and scientists to move beyond a trial-and-error methodology to resolve sanding issues. A successful sand-management strategy can start during the drilling stage and carry through to reservoir depletion.

In the subsurface, the main factors that control whether a reservoir will fail mechanically are rock strength, the effective stress on the formation—a combination of principal earth stresses acting on the rock minus pore pressure—and the stresses introduced by drilling, completion and production.[3] Rock strength can be determined through laboratory uniaxial and triaxial tests, and can be represented graphically by a failure curve, or envelope. The shear and normal stresses on a specified plane under three perpendicular principal stresses are determined by using Mohr's circle. To determine the conditions at which failure occurs, the Mohr-Coulomb failure model is used to relate principal stresses and pore pressure to the cohesion and internal

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3. Desroches J and Woods TE: "Stress Measurements for Sand Control," paper SPE 47247, presented at the SPE/ISRM Eurock 98, Trondheim, Norway, July 8–10, 1998.

friction angle of the rock (right). Failure occurs under tension, compression or, most commonly, when the difference between the maximum and minimum principal stresses becomes large enough to produce excessive shear stress.

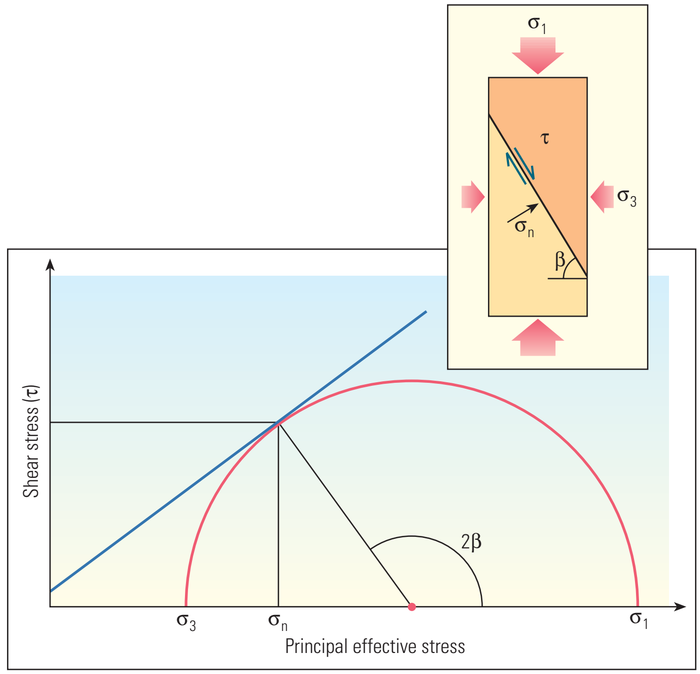
The strength of a rock under downhole conditions depends on several factors. The most important are the cohesion, the internal friction angle, the maximum and minimum principal stresses and the pore pressure. Cohesion is strongly influenced by the degree of cementation of the rock. Well-cemented, consolidated sedimentary rocks tend to be stronger, while poorly cemented, unconsolidated rocks are weaker. Internal friction angle is influenced by the volume fraction of hard particles—typically quartz or feldspar grains—in the rock. Formation grains in weak sandstone reservoirs become disaggregated, or loosened from the rock matrix, because of shear, tensile and volumetric failure.[4]

During production, shear failure caused by either drawdown or depletion can result in a catastrophic quantity of produced sand. Increasing the drawdown generates higher effective stresses around the well or perforation tunnel, and if these exceed the strength of the rock in this geometry, the rock will fail and sand may be produced. Increasing depletion can change the in-situ stresses in the Earth, which can also generate higher shear stresses around the borehole, possibly leading to sand production.

Tensile failure occurs in weak sandstones primarily because of a high fluid-flow rate, which is a function of drawdown. This type of failure is often sporadic, produces relatively low volumes of sand, is aggravated by rapid changes in well production rates, and often stabilizes with time.

Volumetric failure, or pore collapse, is associated with both drawdown and depletion and occurs in high-porosity, low-strength reservoirs. In weak but consolidated rocks, this phenomenon causes subsidence and has been studied extensively in North Sea chalk reservoirs.[5]

Not all sandstones yield disaggregated sand grains under stress. Tests have shown that even weak sandstones—as determined by uniaxial-compression tests and confined triaxial tests—can have wide-ranging sand-production behaviors that are primarily related to rock type.[6] Many events in a reservoir rock's history can change its strength, eventually resulting in the onset of sand production. Additional stresses are placed on the rock matrix when drilling, completing and stimulating a reservoir. Also, rock strength can be reduced by production events, such as acid stimulation, reservoir compaction or increases in water saturation.[7] In weak and unconsolidated rocks, rock strength generally decreases with increasing water saturation, with the largest decrease in strength occurring after only slight increases in water saturation from a dry state.[8]



^ Mohr-Coulomb failure criterion. The Mohr circle (red) represents the state of stress at any orientation in a material body, ranging from the smallest principal effective stress, σ_3, to the largest, σ_1. If the Mohr circle intersects the failure condition (blue), the material will fail in shear. Mohr's circle also provides the normal stress (σ_n) and shear stress (τ) across the failure plane, and the failure angle β, measured from the direction perpendicular to maximum principal stress (*inset*).

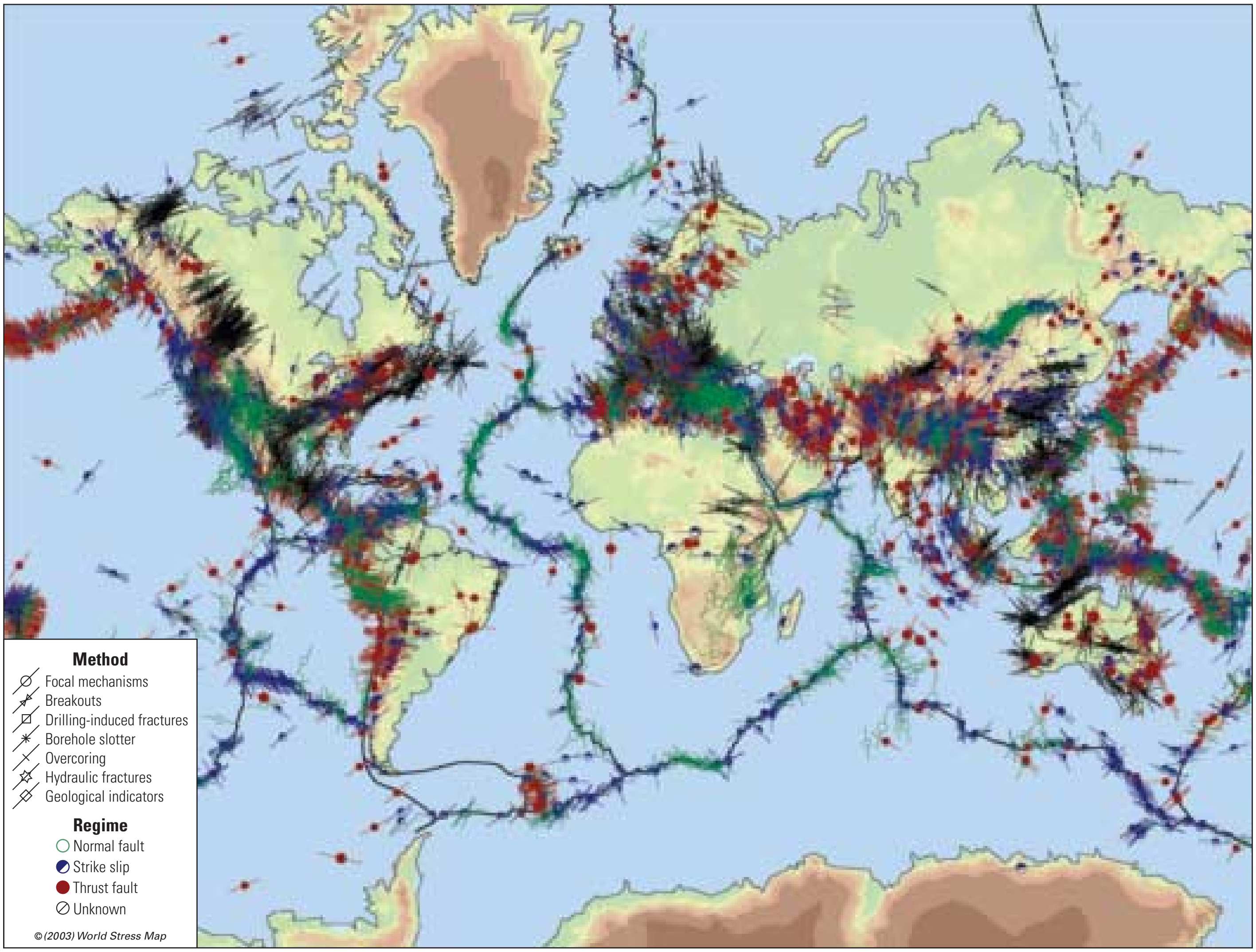
Not all disaggregated sand grains are mobilized by produced fluids.[9] They may stay in the perforation, or in the well, and eventually cover the producing interval. The degree to which sand grains are mobilized depends on factors such as fluid viscosity and fluid velocity, in complex and relatively poorly understood ways.[10] When trying to predict when and where sand production will occur, the failure of a rock and the resulting disaggregation of sand grains must be considered in conjunction with particle erosion and mobilization into the production stream.

There are many ways to avoid or minimize sand production. In very weak, unconsolidated reservoirs, large-scale sand production may be inevitable, so downhole methods to exclude sand production or to consolidate the formation near the wellbore are practical. Sand-exclusion techniques include cased-hole gravel packs, high-rate water packs, frac packing, openhole gravel packs and stand-alone screens—such as slotted liners and expandable screens.

Consolidation techniques involve the injection of resins to stabilize the rock while leaving enough of the original permeability intact to allow the production of reservoir fluids. These resins are sometimes used prior to hydraulic-fracturing techniques for sand control.

Choosing a method to reduce or eliminate sand production in moderately weak reservoirs is less straightforward. Underestimating the sand-production potential may lead to costly sanding problems in the future, while overestimating the sand-production potential may result in unwarranted and expensive installations of downhole hardware, or unnecessary reductions in production rate. Predicting the extent of sand production in moderately weak reservoirs is crucial to minimizing uncertainty when designing a completion. Furthermore, correctly predicting sand production can save operating companies millions of dollars per well.

In many moderately weak reservoirs, screenless-completion methods provide an optimal solution.[11] Techniques such as oriented perforating, selective perforating, screenless hydraulic fracturing and consolidation treatments have reduced sand production, sometimes dramatically. There are also ways to manage sand production at the surface by using appropriate sand separators and through careful monitoring of erosion and accumulation. In such cases, the economics of cleanout and disposal of the sand must be taken into account in the final choice of sand-management techniques. In conjunction with all sand-management methods—exclusion, screenless and surface—producing the well at an optimal rate can be essential to controlling sand production.



^ World stress map. Stress data are compiled from a variety of sources and displayed on stress maps. Downhole measurements, such as borehole breakout and induced-fracture data, are an important source of this stress information. Hydraulic-fracturing data are also useful but often contain no stress orientation details.

A Need To Know

Proper sand management seeks to optimize the completion of wells with sand-production problems. Accomplishing this goal requires understanding the reservoir and the forces that affect formation stability.

Earth-stress data have been compiled from a variety of sources. The magnitude and orientation of horizontal stresses can be displayed on local or global stress maps (above).[12] The predominant source of horizontal stress information

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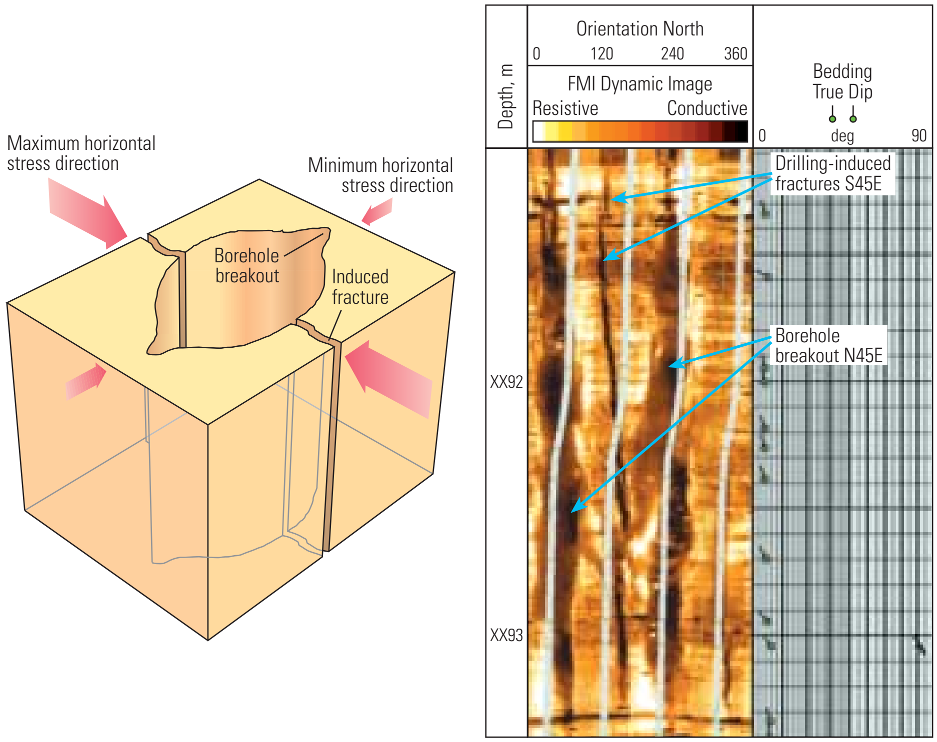

^ In-situ stress direction from borehole images. Borehole imaging data provide detailed stress-direction information (*right*). For example, in a vertical well, borehole breakouts typically are oriented along the minimum horizontal stress direction, while drilling-induced fractures are aligned with the maximum horizontal stress direction (*left*). Induced fractures frequently are near-vertical because the minimum stress is usually horizontal.

is earthquake focal mechanisms—compression, tension or strike-slip—determined from the seismic waves arriving from earthquakes. A small amount of data comes from strain-relaxation and stress-metering techniques. Local stress information in oil and gas development areas often comes from boreholes and includes sonic log data, borehole breakout patterns, induced-fracture directions, and hydraulic-fracturing and microhydraulic-fracturing data.

An important source of earth stress directional data is wireline and logging-while-drilling (LWD) images and measurements.[13] Typically, the largest principal stress is vertical and attributed to the weight of overburden. Sonic, density and pore-pressure data are used to generate a vertical stress profile. Borehole imaging devices, such as the FMI Fullbore Formation MicroImager, the OBMI Oil-Base MicroImager and the GVR geoVISION resistivity tools, provide orientation of induced fractures and borehole breakouts. The minimum principal-stress direction is perpendicular to these fractures and aligned with the elongation of the borehole caused by breakouts (above).

Accurate determination of stress directions is crucial in the proper deployment of oriented perforating gun systems. Perforating in the direction of maximum stress makes hydraulic fracturing more efficient by reducing tortuosity effects during pumping. For sand prevention, oriented perforating in the direction of maximum stability has produced good results. Oriented perforating can be achieved with wireline, coiled tubing or tubing-conveyed methods in vertical, deviated or horizontal wells. Regardless of the method used, oriented perforating has helped minimize sand production, particularly in the presence of stress anisotropy.

Modeling a reservoir's tendency to produce sand also requires knowledge of principal stress magnitudes. To physically measure the magnitude of horizontal stress downhole, a hydraulic-fracturing technique called the DataFRAC fracture data determination service is often used on wells requiring hydraulic-fracture stimulation. After hydraulic-fracture initiation, pressure measurements record the fracture-closing pressure, which is related to the minimum in-situ stress acting perpendicular to the fracture.

An alternative to this procedure was developed using the MDT Modular Formation Dynamics Tester tool on wireline.[14] The MDT tool uses a straddle-packer arrangement to perform openhole microhydraulic-fracturing tests on small intervals. The MDT device injects fluid into an interval at a constant rate until a fracture is initiated. The fracture propagates perpendicular to the direction of the minimum in-situ stress. Similar to the DataFRAC service, this technique measures pressure responses after fracture initiation to determine the minimum principal stress and can be used with other logging tools—for example the DSI Dipole Shear Sonic Imager and FMI tools—to provide a more comprehensive analysis. Microhydraulic-fracturing tests have been used successfully to define the formation stresses prior to performing frac packing and screenless hydraulic fracturing sand-control operations. Stress information, along with other data, is used to build models of the minimum principal stress versus depth. These models are important in both the design and analysis of the

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hydraulic-fracturing treatment. However, mechanically weak zones may fail due to the drawdown between the MDT packers (see “Testing Weak Sands,” *page 24*). To avoid this, the MDT technique can be used in cased holes.[15]

To predict how a sand-management completion will perform over the life of the reservoir, information is also needed about the impact of depletion on reservoir stresses. This information, usually a single number called the reservoir-stress path, can be calculated approximately from the elastic properties of the reservoir and surrounding rock, or calculated more accurately using a full-field geomechanical model, or measured by examining hydraulic fracture records from different stages in the development of the field, if such data exist.

Modern sonic logging devices, such as the DSI tool, measure shear-wave anisotropy to determine in-situ stress directions in both hard, fast formations and soft, slow formations.[16] These tools also provide crucial rock-mechanics parameters to assess formation strength and predict sand-production problems. Measured values of compressional traveltime (t_c) and shear traveltime (t_s) are used to calculate dynamic elastic properties, including Poisson’s ratio (ν) and Young’s modulus (E).

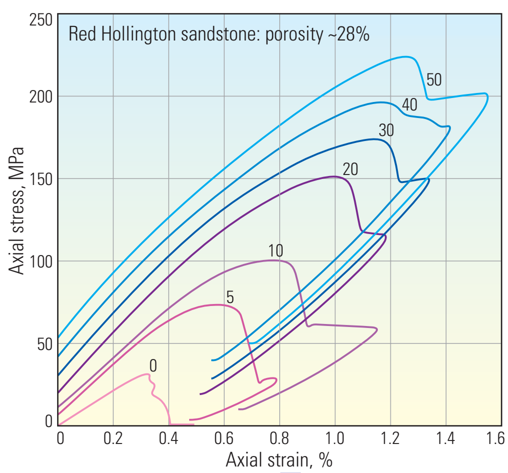
Static rock properties are derived from laboratory tests. In the laboratory, the effective stress on the rock sample governs failure, but sample size, shape, moisture content and defects also influence failure. A failure envelope is constructed using data from several compression tests, in which peak axial stress points are typically plotted against the different confining pressures used during the tests (below). Laboratory test data greatly enhance the overall knowledge of reservoir rock strength and can be used to calibrate log-derived values. However, performing these tests requires specialized equipment, and acquiring representative rock samples may be difficult, if not impossible.

Model Behavior

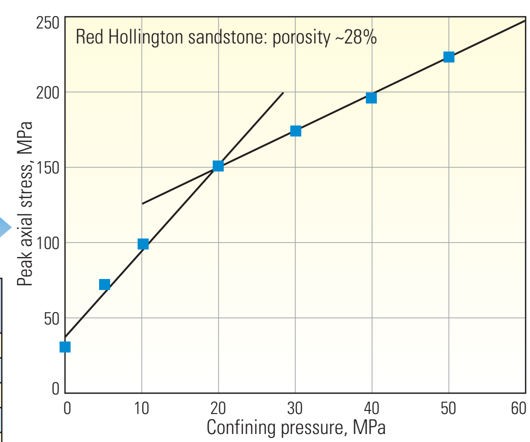
Predicting sand-production behavior starts with developing a mechanical earth model (MEM) to understand a field’s geomechanics.[17] These models are especially important when trying to assess the impact of a given completion method on weak rocks. In its most basic form—one dimension (1D)—an MEM contains information on vertical and horizontal stresses, pore pressure, rock strength, rock properties and geologic data, such as formation dip. An MEM can use additional inputs from geological and geophysical models that define tectonic features, such as faults and folds. Reservoir models that describe field-depletion or pressure-maintenance responses can also be input to an MEM. A well-constructed three-dimensional (3D) MEM allows engineers and geoscientists to determine the state of stress in a reservoir and surrounding strata at any location within a field.

Sand-prediction models focus on failure of reservoir rock and migration of disaggregated sand grains resulting from well-completion practices. Information about the mechanisms that drive sand production is not easily obtained from downhole observations, so much of the knowledge relating to sand prediction has come from laboratory research.

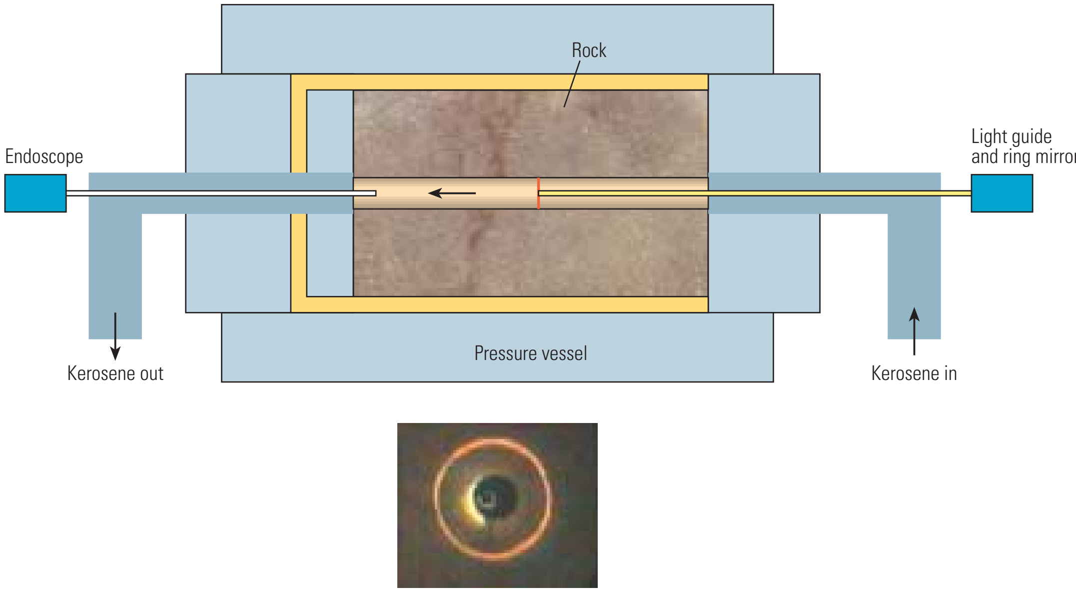
Scientists at Schlumberger Cambridge Research Center (SCR) and Schlumberger Reservoir Completions Technology Center (SRC) conducted perforation-stability experiments on rock samples of different strengths, providing data to develop simulation software that predicts sand failure in weak rocks. These experiments examined sand-production tendencies at various stresses and flow rates to study the effects of perforation hole size, formation grain size and completion geometry—perforation and wellbore orientation—in relation to the principal stresses



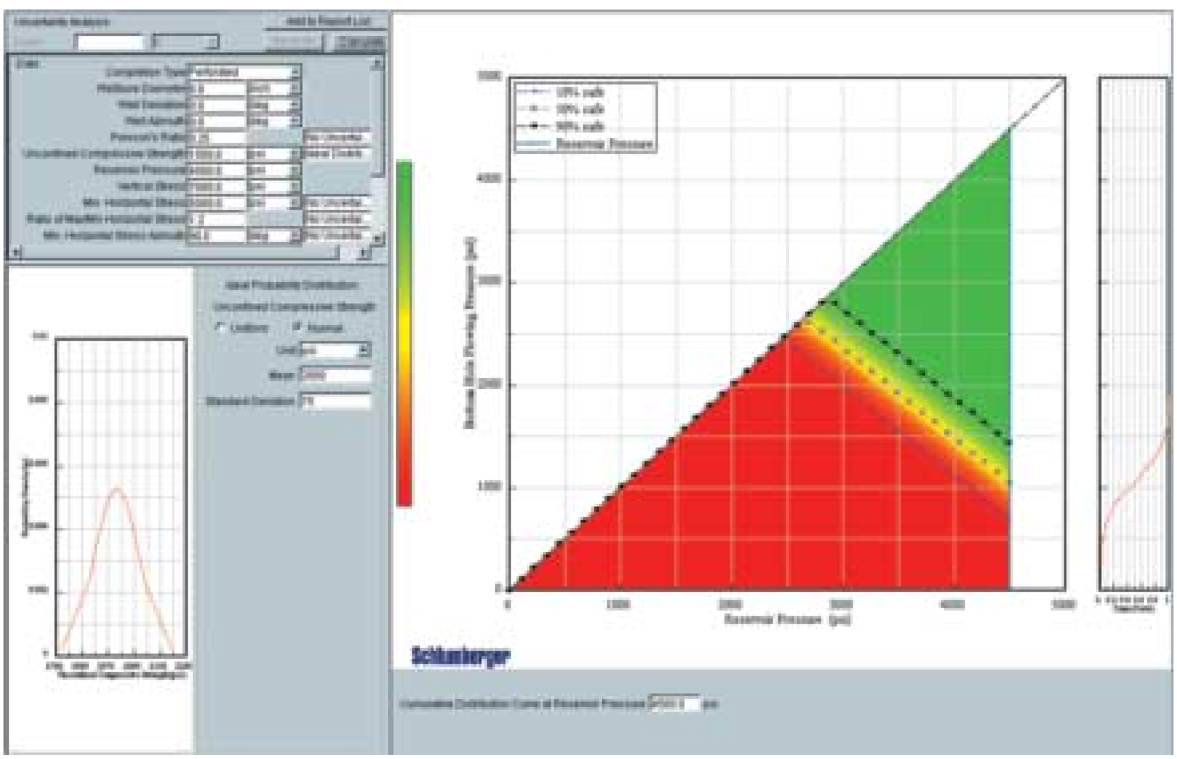
Confining pressure MPa	Peak axial stress MPa
0	31
5	71
10	100
20	151
30	174
40	196
50	224



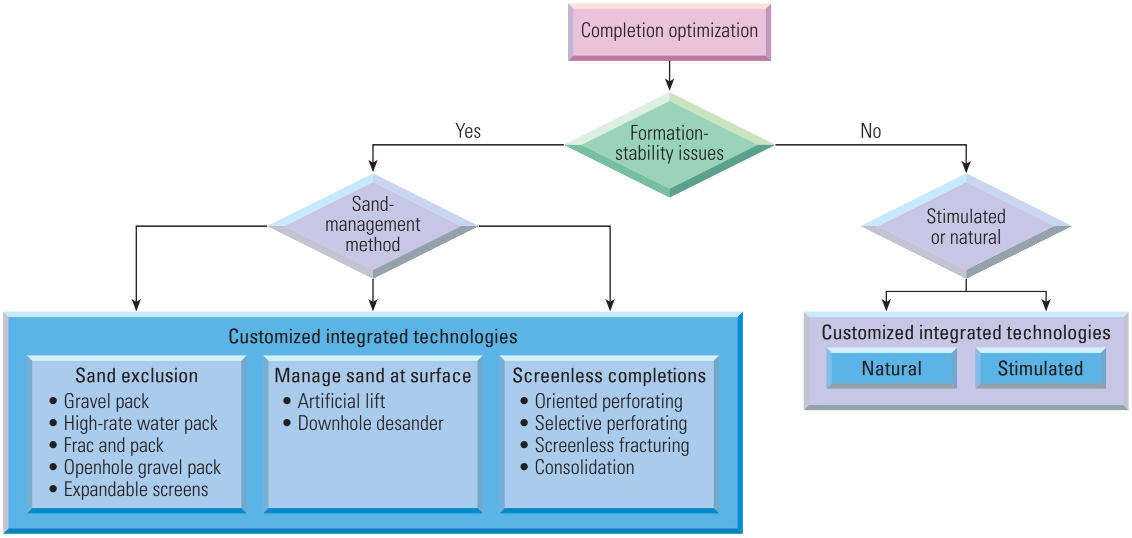
^ Constructing a failure envelope. Reservoir rocks are tested in the laboratory to acquire axial stress and strain data at different confining pressures (*top left*). Normally, each confining pressure used during testing is plotted against the peak axial stress that occurs before failure (*right*), allowing the internal friction angle to be estimated.



^ Laboratory testing designed to visualize sand disaggregation and sand transport mechanisms. A rock sample containing a simulated perforation tunnel is placed in a pressure vessel (*top*). A light guide and ring mirror are used in combination with an endoscope to observe the tunnel while kerosene flows through the tunnel. When possible, cores from representative reservoir outcrops have been used for axial flow testing, in which the displacement of the tunnel walls was documented by imaging (*bottom*). Extensive work at SCR identified different mechanisms across a wide range of rock strengths. This information is compared to sand-production modeling results.



^ Determining the critical drawdown limits. Sand prediction modeling in the Sand Management Advisor software calculates critical drawdown pressure for different openhole or perforated completion options and orientations. Given certain reservoir pressure and bottomhole pressure ranges, the green region defines the sand-free window, while the red area signifies sand failure. Uncertainties associated with input data (*left*) can be applied to the critical drawdown computation to generate uncertainties in the sand-free window. In addition, the cumulative uncertainty distribution is plotted to the right for a reservoir pressure of 4,500 psi [31 MPa].



^ Completion options to balance sand control with production requirements. If formation-stability concerns exist, operators can choose between downhole sand-exclusion technologies or screenless-completion methods. They may also choose to manage existing sand production by careful selection of artificial-lift techniques and practices.

(previous page, top). This work has greatly enhanced sand-prediction modeling, which is based on the peak strength of a rock in a perforation tunnel or wellbore. Schlumberger uses this information to optimize completions to ensure that wells produce at economic rates with an acceptable risk of sand production.

Similar to wellbore-stability analysis, sand-production analysis differs in that the perforation-tunnel pressure is less than reservoir pressure, allowing fluid flow. Or, in the case of openhole completions, wellbore pressure is less than reservoir pressure. Stress calculations are made at the appropriate perforation orientation and phasing to determine minimum drawdown that does not promote shear failure, or the maximum sand-free drawdown. This drawdown is then used to calculate production rates and to establish whether minimum production requirements are achieved. If they are not, the completion design must be modified.

Schlumberger developed proprietary software called Sand Management Advisor to accomplish this analysis. This 3D sand-prediction modeling software requires MEM inputs and exploits the outputs from other analysis tools, such as SPAN Schlumberger perforation analysis and ProCADE well analysis software tools. It also links to the Formation Completion Selection Tool (FCST), a proprietary knowledge-based completion-planning tool, so that experts can optimize completions by screening and ranking the most appropriate completion technologies available.

The sand-prediction tool calculates the critical drawdown pressure for different user-provided completion scenarios and identifies the sand-free production window. Two models are used in computing the critical drawdown pressure at which a formation will fail. A wide range of methods has been used in the past for sand production prediction, for example, using elastoplastic models.[18] Sand Management Advisor uses a proprietary method developed by Schlumberger that takes into account the well-known increase in the strength of holes in rocks as their diameters decrease. The sand-free window defines completion and artificial-lift design limits, for example the maximum allowable drawdown produced by an electrical submersible pump (ESP). Uncertainty can also be considered on six input parameters: Poisson's ratio, unconfined compressive strength, minimum horizontal stress, minimum horizontal stress direction, ratio of the maximum and minimum horizontal stresses, and grain size. For a given completion scenario, this sand-free window is displayed graphically by plotting reservoir pressure versus bottomhole flowing pressure (BHFP), highlighting the sand-free drawdown window and the various levels of uncertainty (previous page, bottom). This and other tools can also be used in the selection of sand-management candidate wells.

From Prediction to Practice

With knowledge of a reservoir, its stresses and the probability of encountering sand production, operating companies can make informed decisions about the best approach to optimize well completions and limit the impact of producing sand (above). Initially, the question is whether to control or to prevent sand production. Sand-exclusion methods may be required when sand production is certain, or when the risk associated with unforeseen sand production is high—for example, in subsea completions or high-rate gas wells. One of a variety of screenless-completion methods may offer the best option when sand production can be avoided or at least limited. Regardless of the method, proper sand management is the vehicle needed to balance sand control with the desired production results through optimized completions.

Gravel packing is a common sand-exclusion technique that has been used since the 1930s.[19] This procedure involves pumping a designed slurry, comprising gravel of a specific size and an appropriate carrying fluid, to fill the annular

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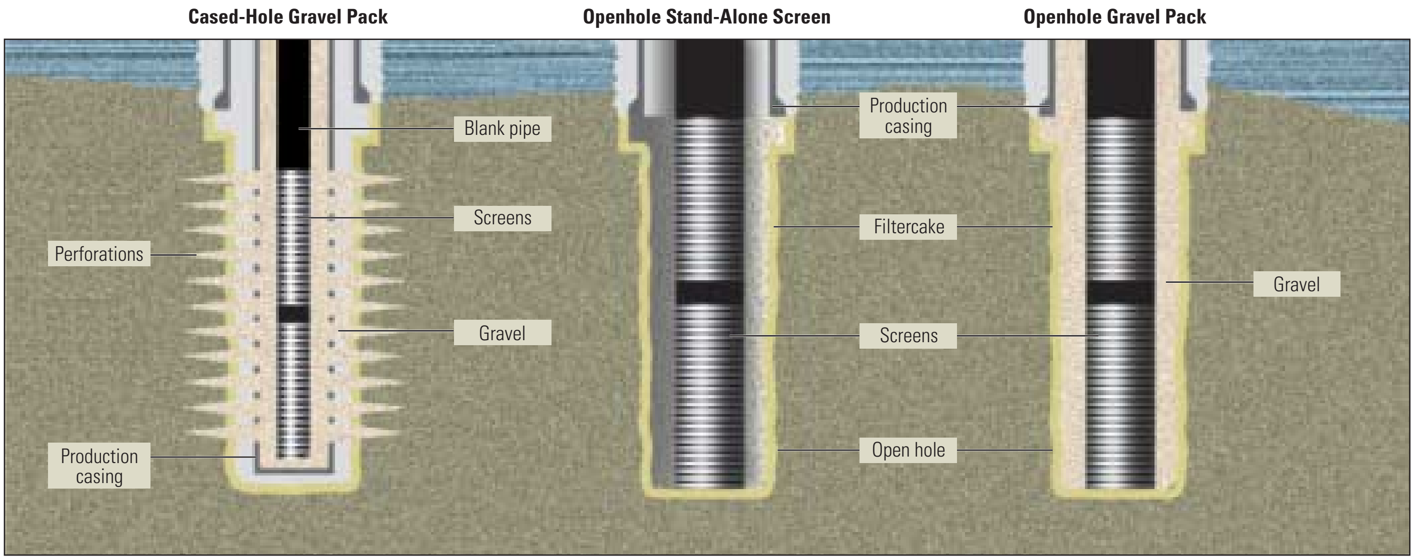


^ Cased-hole and openhole gravel packs. Cased-hole gravel packing requires perforating of the completion interval and is often used in vertical, or near-vertical, wells producing from laminated reservoirs (*left*). Openhole stand-alone screens are used to control sand production in clean reservoirs that have relatively short production lives (*center*). Openhole gravel packs are common in horizontal wells, require no perforations, and are a viable option in highly productive, risky deepwater completions (*right*).

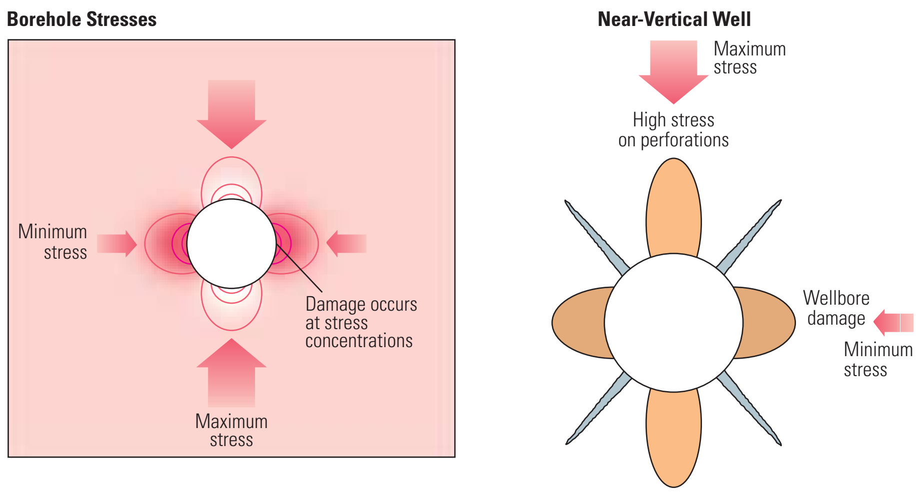
space between a carefully selected centralized screen and perforated casing, or the formation in the case of an openhole gravel pack (above).

Cased-hole gravel-pack design should include perforating optimization. The selection of the most suitable perforating-gun system and perforating method can also improve gravel-pack effectiveness by minimizing perforation damage.[20] In moderately competent reservoirs, the PURE Perforating for Ultimate Reservoir Exploitation system produces the optimum amount of underbalance for a given reservoir pressure, generating improved perforation cleanup.[21]

Openhole gravel packs require removal of filtercake from the completion in addition to the standard design considerations. Careful selection of proper drilling and completion fluids helps ensure adequate filtercake development and its subsequent removal. It is imperative to remove as much filtercake as possible to maximize gravel-pack permeability. This is best accomplished by using a fully integrated process such as the MudSOLV filtercake removal service and antiswab tools to maintain hydrostatic pressure on the wellbore during the gravel-packing operation. The MudSOLV service includes full consideration of the completion, selection of the chemistry with the lowest risk, the use of performance metrics, economic analysis and laboratory verification testing.[22]

In low-permeability reservoirs, reservoirs producing high-viscosity fluids, or layered reservoirs with low net-to-gross pay intervals, the technique of frac packing has been widely successful.[23] In soft rocks, this method produces a short, wide hydraulic fracture and relies on achieving a tip screenout (TSO) fracture. Unlike conventional hydraulic fracturing, TSO designs limit fracture length by dehydrating the proppant pack within the fracture early in the treatment. This helps prop the fracture near the tip, creating a short but conductive flow path to the wellbore.

This technique increases the effective completion radius and the area open to flow, and reduces sand production associated with high fluid velocities and unstable perforations. In the past, separate operations included wellbore cleanout, sand-exclusion screen installation and gravel packing, all conducted after fracturing. However, advances in downhole hardware associated with the STIMPAC fracturing and gravel-packing service now allow the fracturing operation to be completed with the screen already in place, and then followed by gravel packing.



^ Stress concentration around a borehole. Perforated completion designs for sand control should consider the stresses around the borehole to help prevent perforation-tunnel failure (*left*). Unlike perforating for hydraulic fracturing, perforations should avoid the highly stressed regions typically aligned with the maximum horizontal stress in vertical wells, which is the vertical direction in horizontal wells (*right*). Perforating in the minimum horizontal stress direction should also be avoided to minimize perforation-tunnel failure. Oriented perforating allows the perforations to be aligned based on perforation stability models to optimize a completion.

There is also a screenless method of frac packing that involves oriented perforating, injecting resin to stabilize the formation and using resin-coated proppants and fiber technology to prevent proppant flowback (see "Going Screenless in Japan," *page 21*). This technique joins a growing list of screenless options when operators choose to prevent failure rather than to exclude sand production.

In moderately weak but consolidated zones, screenless-completion techniques offer effective solutions to reduce or eliminate sanding, often at lower cost and risk and with increased hydrocarbon production.[24] As an important part of sand management, screenless techniques draw from a range of individual or combined technologies such as selective, dynamically underbalanced, optimally phased and oriented perforating techniques, TSO fracturing designs and indirect vertical fracturing (IVF) techniques, proppant-flowback control, and resin injection for formation consolidation.

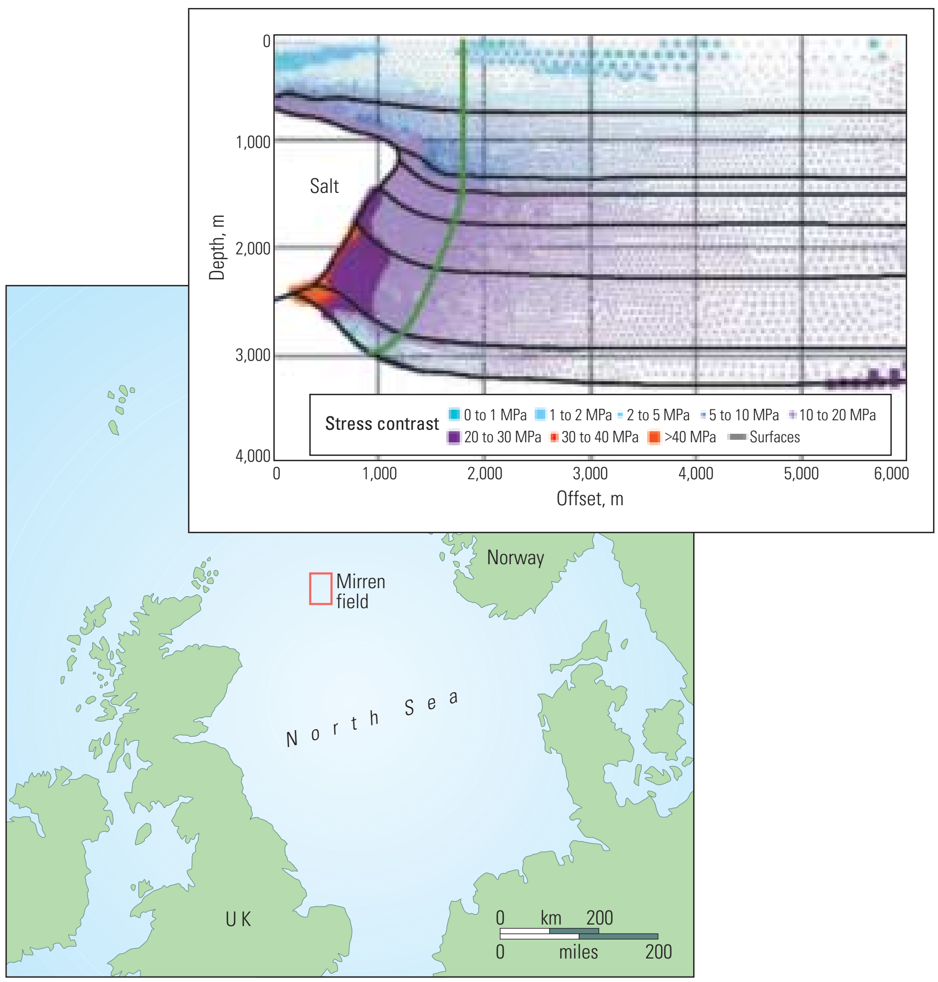
Extensive research and field experience have demonstrated the importance of perforation orientation to perforation stability and sand production. When hydraulic fracturing is planned to help prevent sand production, perforations should be aligned with the preferred fracture plane (PFP), or parallel with the maximum in-situ stress direction.[25] Orienting perforations along the maximum in-situ stress direction reduces tortuosity, or the restrictions on near-wellbore flow during hydraulic fracturing. Today, unsurpassed accuracy, repeatability and verification are available with the OrientXact tubing-conveyed oriented perforating system (see "Perforations on Target," *page 28*).

However, for wells with perforated-only completions in weak reservoirs, alignment with the PFP will not necessarily result in the most stable perforation tunnels and may instead lead to increased sand production. With a 3D sand-prediction model, the state of stress—the magnitude and direction of the three principal stresses—around the wellbore is modeled, allowing completion experts to select the perforation orientations that minimize stress contrast and maximize perforation stability (previous page, bottom).[26] New oriented perforating technologies have allowed the industry to exploit an increased understanding of the relationship between near-wellbore stresses and sand production. This technique has now been applied worldwide and its use continues to grow.

Oriented Perforating Success in the North Sea

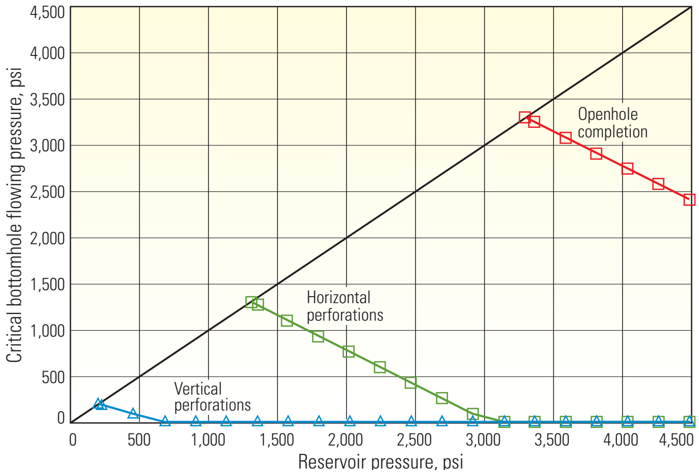
Stress contrasts, or high deviatoric stresses, are the source of many borehole-stability and sand-production problems and can be made more severe by local geologic features such as salt diapirs. Given the complex state of stress in the strata adjacent to a salt diapir, BP was concerned about the potential for sand production to jeopardize well productivity and integrity, and production facilities at Mirren field, east of Scotland in the North Sea. Moreover, as the wells produce, depletion causes the effective stress in the reservoir to increase, raising the potential for sand production. With only two subsea horizontal producing wells planned for field development, BP needed to select a completion method that would avoid potential sand production and minimize future intervention requirements.

To simulate the principal stress conditions in the presence of a salt diapir, BP constructed a comprehensive MEM for the Mirren field (below).



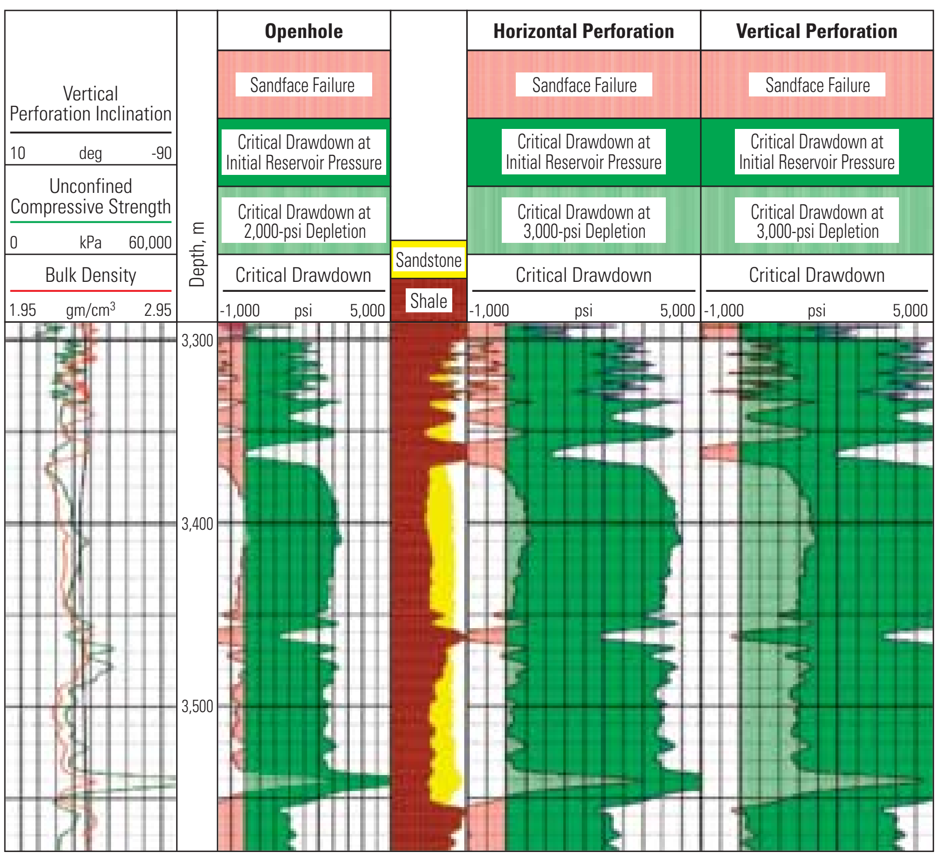
^ Location of Mirren field (*bottom*). Complex stresses surround a salt diapir in Mirren field and must be considered in both drilling and completion operations (*top*). 3D modeling predicts that the maximum stress orientation near the diapir is tilted 20° to 40° from horizontal, making perforated completion design more complex.

20. Venkitaraman A, Behrmann LA and Chow CV: "Perforating Requirements for Sand Control," paper SPE 65187, presented at the SPE European Petroleum Conference, Paris, France, October 24–25, 2000.
21. Bakker E, Veeken K, Behrmann L, Milton P, Stirton G, Salsman A, Walton I, Stutz L and Underdown D: "The New Dynamics of Underbalanced Perforating," *Oilfield Review* 15, no. 4 (Winter 2003/2004): 54–67.
    Stenhaug M, Erichsen L, Doornbosch FHC and Parrott RA: "A Step Change in Perforating Technology Improves Productivity of Horizontal Wells in the North Sea," paper SPE 84910, presented at the SPE International Oil Recovery Conference in Asia Pacific, Kuala Lumpur, Malaysia, October 20–21, 2003.
22. Ali et al, reference 19.
23. Ali S, Norman D, Wagner D, Ayoub J, Desroches J, Morales H, Price P, Shepherd D, Toffanin E, Troncoso J and White S: "Combined Stimulation and Sand Control," *Oilfield Review* 14, no. 2 (Summer 2002): 30–47.
24. Acock et al, Riddles et al, and Pitoni et al, reference 11.
25. Behrmann L, Brooks JE, Farrant S, Fayard A, Venkitaraman A, Brown A, Michel C, Noordermeer A, Smith P and Underdown D: "Perforating Practices That Optimize Productivity," *Oilfield Review* 12, no. 1 (Spring 2000): 52–74.
    Almaguer et al, reference 13.
26. Sulbaran AL, Carbonell RS and López-de-Cárdenas JE: "Oriented Perforating for Sand Prevention," paper SPE 57954, presented at the SPE European Formation Damage Conference, The Hague, The Netherlands, May 31–June 1, 1999.



^ Critical drawdown pressures for three scenarios of perforated completions in a Mirren horizontal well. The first scenario considered an openhole completion (red). The second scenario examined drawdown conditions when perforations are shot horizontally (green), and the third case shows the drawdown conditions when vertical perforations are used (blue). The vertical perforations clearly produce the largest sand-free window and suggest the reservoir sand should not fail until the reservoir pressure declines to less than 500 psi [3.4 MPa].

This 3D model, originally developed to provide wellbore-stability information, enabled the successful drilling of two wells in the field.[27] Significantly, the 3D model predicts that the maximum stress orientation near the diapir is tilted 20° to 40° from horizontal, potentially impacting BP sand-avoidance efforts in two planned horizontal production wells, the East and West wells. Building on the MEM, BP constructed a geomechanical model along the planned trajectories of two of the wells using log data—including gamma ray, compressional traveltime, t_c, and density data—core measurements, leakoff tests and reservoir pressure measurements from offset wells. Shear data, or t_s, were estimated using compressional information from the sonic tool. The dynamic rock properties calculated from the sonic and density measurements were converted to static properties and then calibrated to rock strengths measured in cores from offset wells. In addition, BP analyzed the average grain size in cores of the Mirren field reservoir rock.



^ Continuous critical drawdown data. Track 1 displays vertical perforation orientation, computed unconfined compressive strength (UCS) and bulk density data. The three scenarios are presented in Tracks 2, 4 and 5. The openhole case is run using a depletion of 2,000 psi [13.8 MPa], while the perforated scenarios use a depletion of 3,000 psi [20.7 MPa]. The light green area represents the critical drawdown at depletion, and the critical drawdown at the initial reservoir pressure (dark green) is also presented.

With the Schlumberger Sand Management Advisor sand-prediction model, critical drawdown pressures were calculated across the anticipated completion intervals for three different horizontal completion scenarios: openhole completion, horizontal perforations and vertical perforations (previous page, top). Results indicated that resistance to sand failure dramatically improves for perforated completions and sand production could be delayed for several years. Additionally, perforations oriented vertically were significantly more stable than those oriented horizontally.

The critical drawdown analysis showed that under openhole conditions, the reservoir sands could withstand a drawdown of 2,175 psi [15 MPa] at the initial reservoir pressure of 4,550 psi [31.4 MPa]. However, simulation predictions for the field-development plan indicated that formation pressures would deplete to the extent that any amount of drawdown would cause sand failure after one year of production. Searching for an alternative to sand screens, which pose a high cost of installation and a risk of failure in later life, BP explored perforated completion options.

Horizontal perforations—the worst of the cased-hole perforation scenarios—would improve the resistance to failure compared with the openhole case, allowing drawdown to 3,150 psi [21.7 MPa] at the initial reservoir pressure. After four and a half years of production, once the reservoir pressure dropped below 1,350 psi [9.3 MPa], sand failure would be expected. When perforations are oriented in the more stable vertical direction, the 3D sand-prediction model suggests that the formation should not fail until the reservoir pressure declines to less than 500 psi [3.4 MPa], which is beyond the anticipated economic life of the field. The most stable perforation orientation is actually angled slightly away from vertical to increase the distance between perforations, thereby reducing the overlap of stress concentrations around each perforation.

The critical drawdown analysis was extended to include the entire completion interval to examine the long-term effects of reservoir depletion (previous page, bottom). The three scenarios were again examined and compared at the initial reservoir pressure, at 2,000-psi [13.8-MPa] depletion for the openhole case, and at 3,000-psi [20.7-MPa] depletion for both the horizontal and vertical perforation scenarios. The weakest sands and shaly intervals within the section were predicted to fail regardless of perforation orientation, so the completion design recommended that engineers avoid perforating them.

The East well was drilled and completed in 2002. Critical drawdown pressures were recalculated using the East well log data, which included density and t_c and t_s from an LWD sonic tool. A multidisciplinary team selected perforation intervals from the revised analysis, and the oriented perforating job was completed successfully. Later in 2002, the same procedure was followed on the West well. The wells were put on production in November 2002 and exhibited slightly negative skin values, indicating no formation damage. With the exception of some initial fine-grained sand production resulting from perforation cleanup, the wells are producing with only minimal sand influx, matching expectations from the modeling.

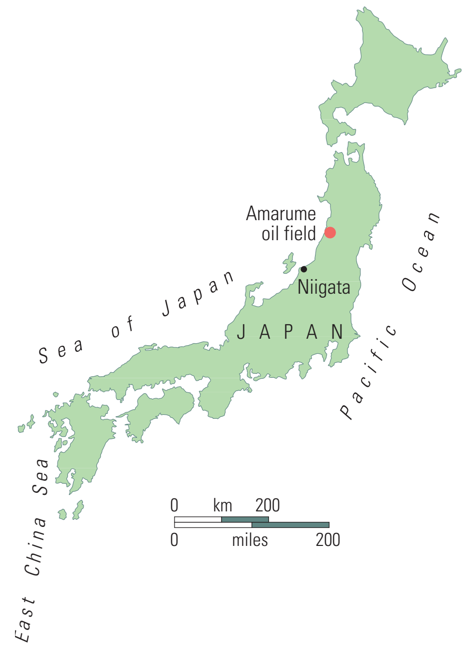
Going Screenless in Japan

Amarume field, operated by the Japan Petroleum Exploration Company, Limited (JAPEX), is an onshore oil field close to Niigata on Honshu Island, Japan (right). Produced since the early 1960s, the field has a reservoir pressure that has dropped from 1,800 psi [12.4 MPa] to 650 psi [4.5 MPa]. Sand production observed in six wells led JAPEX to reduce drawdown in all the wells to 55 psi [0.4 MPa].

During the planning stages of Well SK 74D, Schlumberger proposed a completion solution that would help limit sand production. Prior to selecting the type of completion, the planning team characterized reservoir stresses and completed a sand-prediction analysis.

Special software was used to translate the gamma ray, density and sonic—t_c and t_s—data from a vertical offset well, the AMR TRC-1, to the planned deviated SK 74D well. RockSolid wellbore stability software was then used to construct a 1D MEM, which was calibrated with core-strength data from multistage triaxial tests. Borehole images were not available, but because the zone of interest was shallow, it was thought that the orthogonal horizontal stresses were similar in magnitude. However, a previously acquired vertical seismic profile (VSP) and the DataFRAC pressure data indicated stress anisotropy did exist.

The Sand Management Advisor sand-prediction software, using the 1D MEM as input, provided the critical drawdown pressures to identify potential sand-production zones. A combination of low unconfined compressive strength (UCS) between 100 and 500 psi [0.7 and 3.4 MPa] and 60% reservoir depletion meant that shear failure could occur at the sandface in the perforations. During the analysis,



^ Location of Amarume field in Japan.

perforated completion parameters were examined, including perforation deviation from vertical, perforation diameter and perforation orientation. Plots show that sand failure would occur, regardless of the perforating job design. The critical drawdown plots predicted sand production at any drawdown pressure and indicated a need for sand control. The low reservoir pressure and predicted low well productivity made any sand-exclusion screen completion uneconomical and instead suggested the need for a less expensive, screenless hydraulically fractured completion.

For a screenless fractured completion in this well, the following steps were identified as critical to treatment success:

- *High-quality well cementing* ensures good zonal isolation across weak and depleted zones. The success of any fracturing treatment requires good zonal isolation to help pump fracturing fluid and proppant to the desired zone. Achieving zonal isolation is even more of a challenge when cementing across depleted reservoirs where loss of circulation is anticipated. For this well, a two-stage cementing operation with 1.6-specific gravity LiteCRETE slurry was used.[28] Cement bond logs and USI UltraSonic Imager logs indicated good bonding over the cemented intervals.
- *Optimized perforating* helps ensure that formation fluid is filtered through the proppant

27. Ali et al, reference 17.
28. Al-Suwaidi A, Hun C, Bustillos J, Guillot D, Rondeau J, Vigneaux P, Helou H, Martínez Ramírez JA and Reséndiz Robles JL: "Light as a Feather, Hard as a Rock," *Oilfield Review* 13, no. 2 (Summer 2001): 2–15.

pack in the fracture prior to exiting the perforations. The perforated interval was limited to 6 ft [1.8 m] at zero-degree phasing and oriented at 180 degrees on the low side of the borehole. The perforation entrance-hole size was selected to be less than the designed fracture width.

- *In-situ consolidation* stabilizes unconsolidated rock around the perforations by injecting a resin into the formation.
- *Tip-screenout (TSO) fracturing* ensures tightly packed proppant from the fracture tip to the wellbore. This is essential for filtering any sand from fluids during production. A key to achieving a TSO fracture is determining fluid efficiency, fluid-loss coefficient and closure pressure, which can be obtained from DataFRAC calibration and step-rate tests. A large difference between the assumed values of fluid efficiency, fluid-loss coefficient and closure pressure compared with the DataFRAC results demonstrated the importance of this calibration to the success of this screenless sand-control method.
- *Proppant-flowback control* improves the longevity of the packed fracture. For this well, PropNET hydraulic fracturing proppant pack fibers were added to all stages of the proppant.[29]

At Well SK 74D, the upper and lower B2 zones were completed using the screenless hydraulic-fracturing technique (below). Early results indicate sand-free production. JAPEX operations, completions and reservoir teams considered this a successful application for controlling sand production.

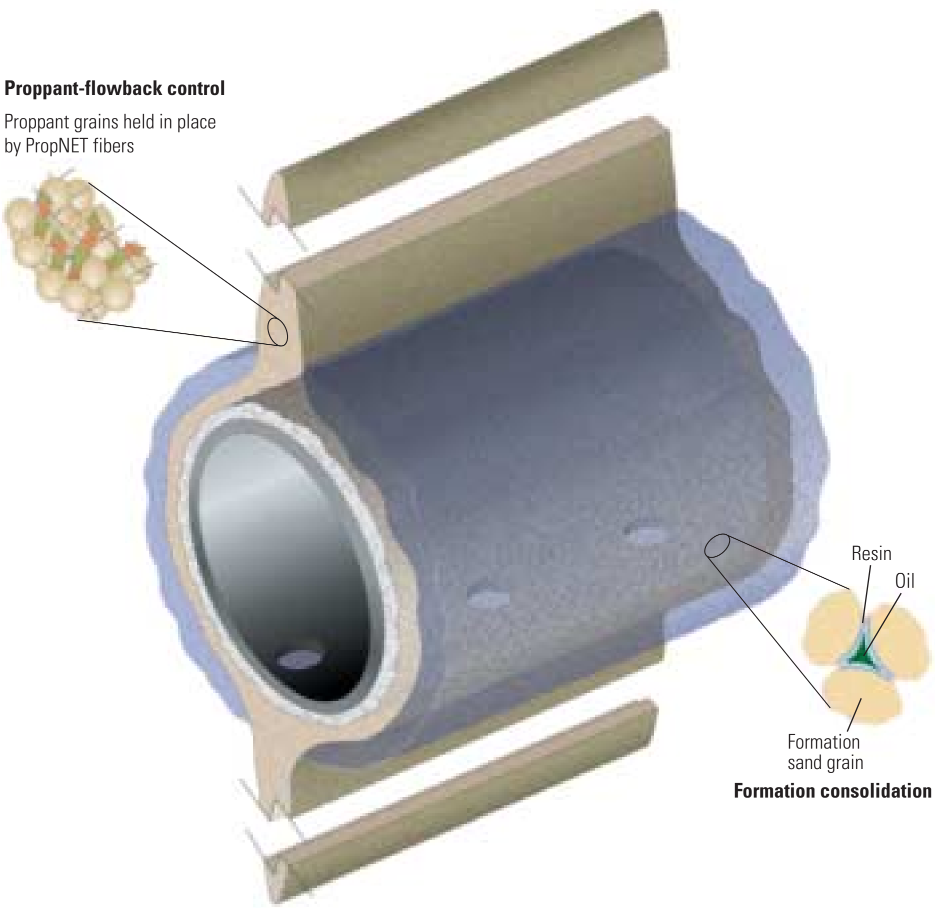
Integrating Technologies

Successful sand management requires an integrated approach to problem-solving and appropriate utilization of the latest technology. This was clearly demonstrated by BP and Schlumberger on Well P110 in the deepwater Foinaven field, West of Shetlands (next page, top).[30] The Foinaven field is a faulted anticlinal structure, featuring dip closure, faults and stratigraphic pinchouts as trapping mechanisms. Paleocene reservoir rocks have been classified as channelized, siliciclastic turbidites that formed interbedded to massive sandstones. Reservoirs range in porosity from 20 to 30%, have permeabilities of 500 to 2,000 mD and produce 26° API gravity oil. Reservoir characteristics, such as heterogeneity and varying productivity, contribute to wide-ranging reserve estimates. In the P110 well, the T25 reservoir target was best exploited by completing a 3,075-ft [937-m] horizontal openhole section.

Completing the long, horizontal openhole section remained a challenge; even with precise well placement, unstable shales and sand production can severely impact well and field economics in this area. A major concern for BP and Schlumberger was a 530-ft [162-m] unstable shale section between two sandstone reservoirs. This shale had the potential to slough into the hole during gravel-packing operations, possibly causing screenout or damage to the gravel-pack permeability. In previous wells, to help address stability issues, oil-base mud (OBM) was used to drill horizontal sections, and stand-alone screens were installed for sand control. In certain instances, particularly with high water cut, stand-alone screens required lower production rates to keep sand production manageable and to reduce erosion rates. Also, limited core data from the previously undeveloped T25 reservoir suggested these sandstones were much finer grained and less sorted than typical sandstones in the Foinaven field. For these reasons, the BP team worked with Schlumberger to improve sand management in the P110 well.

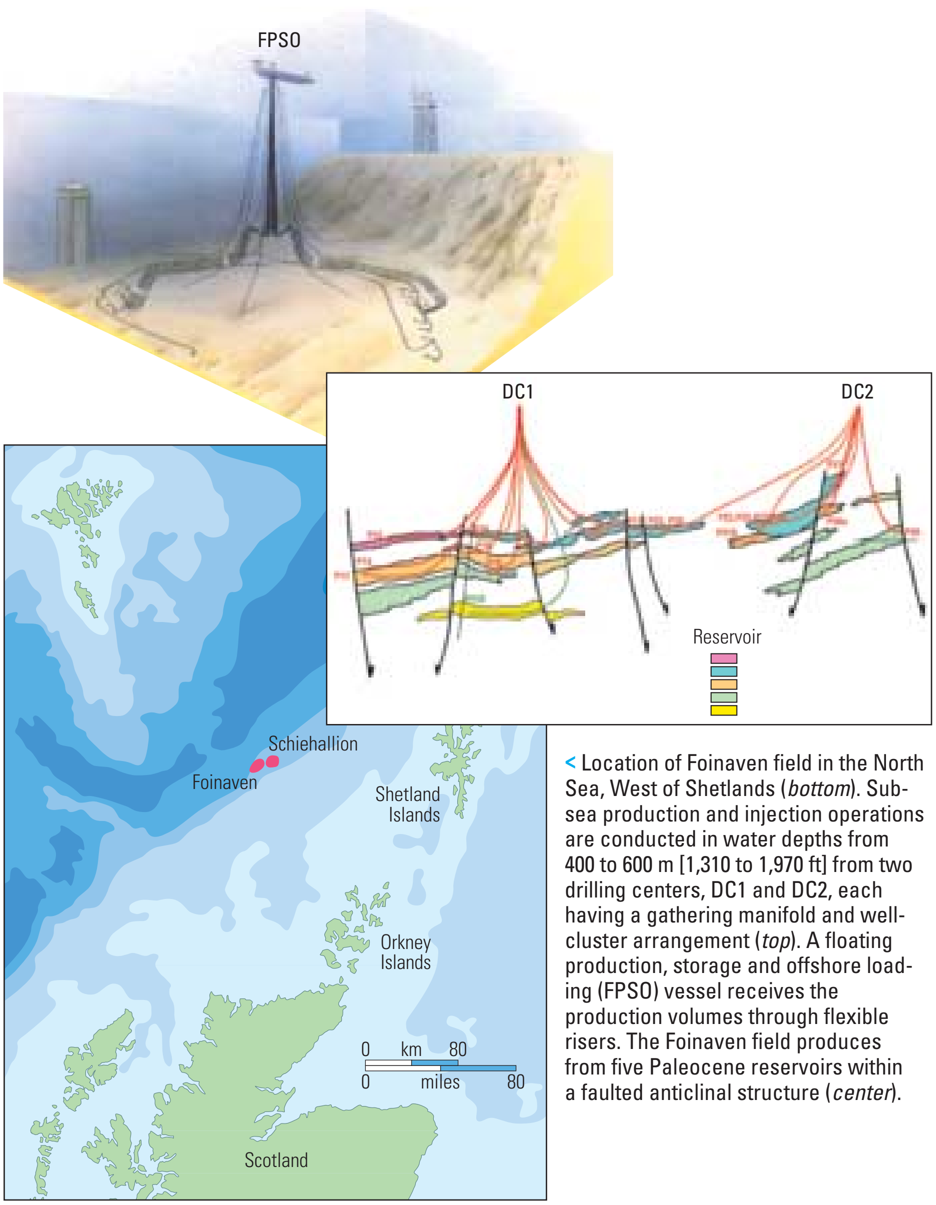
Several techniques contributed to a successful completion. To reduce formation damage, part of the solution included the first use of a water-base drilling mud (WBM) in the P110 horizontal well. After extensive testing, BP found a WBM that fulfilled the requirements for drilling the Foinaven reservoirs.

Studies from earlier wells determined that a stand-alone screen would be inadequate to control sand production from the T25 reservoir, so the new solution also involved an openhole gravel pack (OHGP), the first ever for a deepwater Foinaven field horizontal completion. The



^ Screenless hydraulic fracturing for sand control. A combination of technologies is used to create a stable propped fracture that provides sand control with minimal proppant flowback. The perforating job was designed to optimize the creation of the fracture. After perforating, injected resin was used to consolidate the formation around the wellbore. A TSO fracture created a tightly packed fracture capable of providing sand control and limiting proppant flowback.

29. Acock et al, reference 11.
30. Wilson A, Roy A, Twynam A, Shirmboh DN and Sinclair G: "Design, Installation, and Results from the World's Longest Deep-Water Openhole Shunt-Tube Gravel-Pack West of Shetlands," paper SPE 86458, presented at the SPE International Symposium and Exhibition on Formation Damage Control, Lafayette, Louisiana, USA, February 18–20, 2004.
31. Naturally occurring sand and synthetic proppants are specified according to sieve analysis based on particle-size distributions and percentage of particles retained by screens with standard US mesh sizes.
32. Ali et al, reference 19.

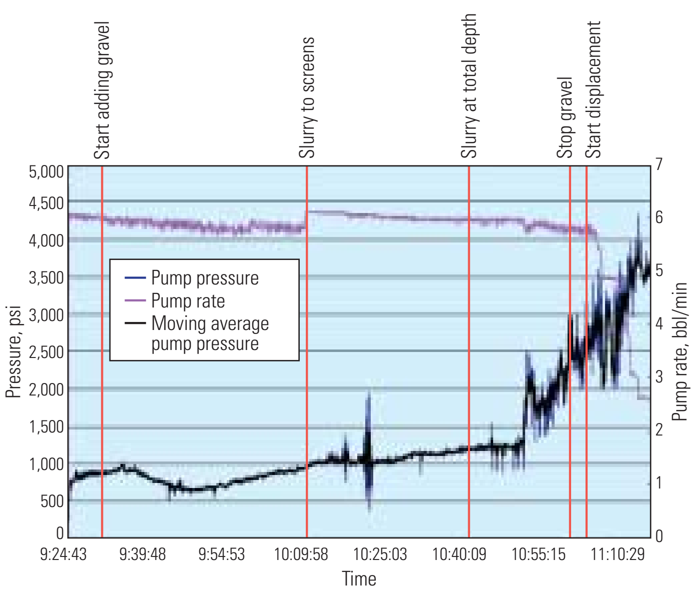


< Location of Foinaven field in the North Sea, West of Shetlands (*bottom*). Subsea production and injection operations are conducted in water depths from 400 to 600 m [1,310 to 1,970 ft] from two drilling centers, DC1 and DC2, each having a gathering manifold and well-cluster arrangement (*top*). A floating production, storage and offshore loading (FPSO) vessel receives the production volumes through flexible risers. The Foinaven field produces from five Paleocene reservoirs within a faulted anticlinal structure (*center*).

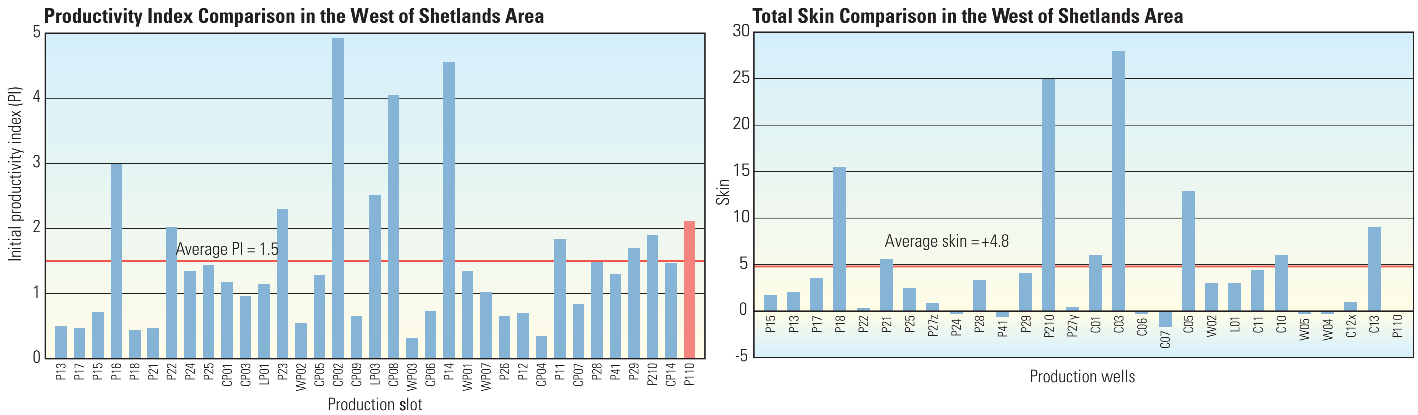
viscoelastic surfactant (VES) ClearPAC fluid was selected as the carrier fluid, reducing friction while pumping the gravel-pack slurry, increasing gravel-carrying capacity and minimizing damage to the gravel pack. Schlumberger tested the VES carrying fluid for compatibility and productivity with the WBM. The treatment incorporated the MudSOLV service to ensure that cleanup would be accomplished while gravel packing. The compatibility test showed that the ClearPAC fluid maintained its fluid properties when introduced to the filtercake cleanup chemicals and the disassociated filtercake, which was essential for the simultaneous treatment. Moreover, the ClearPAC fluid provided excellent shear-thinning properties to the combined treatment, helping it to flow across the troublesome shale sections without causing sloughing.

BP fully characterized the reservoir's grain-size distribution to select the optimal gravel and screen sizes. This study included sieve, laser and scanning electron microscope (SEM) analysis on sidewall cores of the T25 reservoir from a 1994 appraisal well. The company developed an integrated model that utilized the three different methods for particle-size determination. The particle-size distribution model was then used to create an artificial core pack to test sand retention and define the requirements of both the gravel and screen to be used in the completion. BP selected 30/50-mesh synthetic gravel for its higher permeability and superior performance during coreflood filtercake liftoff tests.[31] BP also decided to run 8-gauge wire-wrapped screens because, unlike the finer screens, they retained 96% of the solids and resisted the tendency to plug.

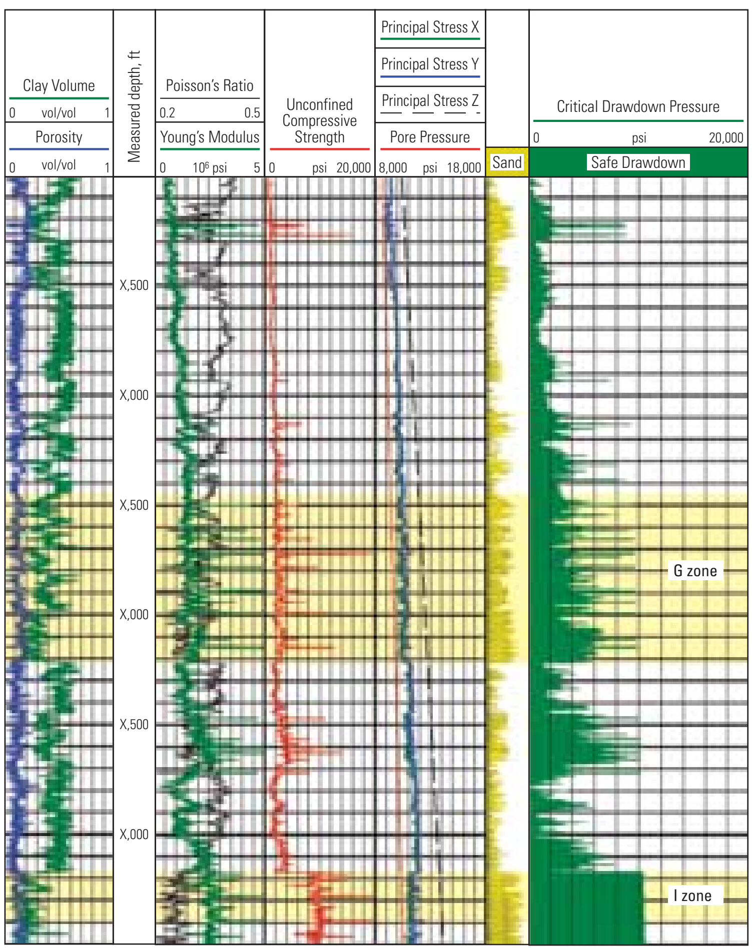
Another crucial aspect of installing this OHGP completion was the need to maintain a continuous overbalanced hydrostatic pressure during the packer-setting process so that the operation experienced no filtercake or formation collapse. Schlumberger accomplished this, along with simultaneous filtercake-cleanup treatment, using the QUANTUM packer and the horizontal openhole AllPAC screen system.[32] The system worked as designed, maintaining positive pressure on the formation and filtercake during the operation (left). The use of effective



< Keeping up the pressure. The plot shows the surface pumping pressure recorded during the installation of the openhole gravel pack in the P110 well. Maintaining positive pressure on the formation and filtercake while pumping was critical to the successful placement of an effective gravel pack. A total of 527 barrels [83.8 m^3] of slurry, carrying 100,000 lbm [45,360 kg] of gravel was pumped in less than two hours and resulted in 100% pack efficiency.



^ Productivity index and skin comparison. After the new completion that included the MudSOLV filtercake cleanup service, ClearPAC fluid system, the QUANTUM packer and the AllPAC screen system, the P110 well performed much better than the majority of the wells in Foinaven field. It exhibited a higher productivity index (*left*) with a skin of zero (*right*). The productivity index comparison was made on 35 production slots, while the skin comparison was made on 28 production wells. In this case, production slots and production wells are not comparable.



^ Critical drawdown log for Trident Well 1. The data from the Trident Well 1 indicated that the Wilcox G zone is a serious risk because of potential formation collapse when exposed to excessive drawdown levels during MDT testing and sampling. The Wilcox I zone was substantially more competent. Clay volume and porosity are displayed in Track 1, computed Poisson's ratio and Young's modulus are presented in Track 2, calculated unconfined compressive strength (UCS) is shown in Track 3, and the computed principal stresses and pore pressure are displayed in Track 4. Track 5 shows the critical drawdown pressures calculated from the sand-prediction modeling tool.

technology, proper planning and an integrated approach to sand management resulted in successful packing of the entire interval.

The new completion design in the Foinaven field performed extremely well compared with the average performance of more than 30 horizontal wells in the West of Shetlands area, for both oil production and sand-control effectiveness. An early buildup test revealed not only a zero skin compared with a 28-well average skin of +4.8, but also a higher productivity index (above). During the initial production test, the P110 well showed a rate of 20,500 B/D [3,260 m^3/d] with a fully open choke. This was attributed to improved sand control and the reduced damage associated with the drilling and completion operations.

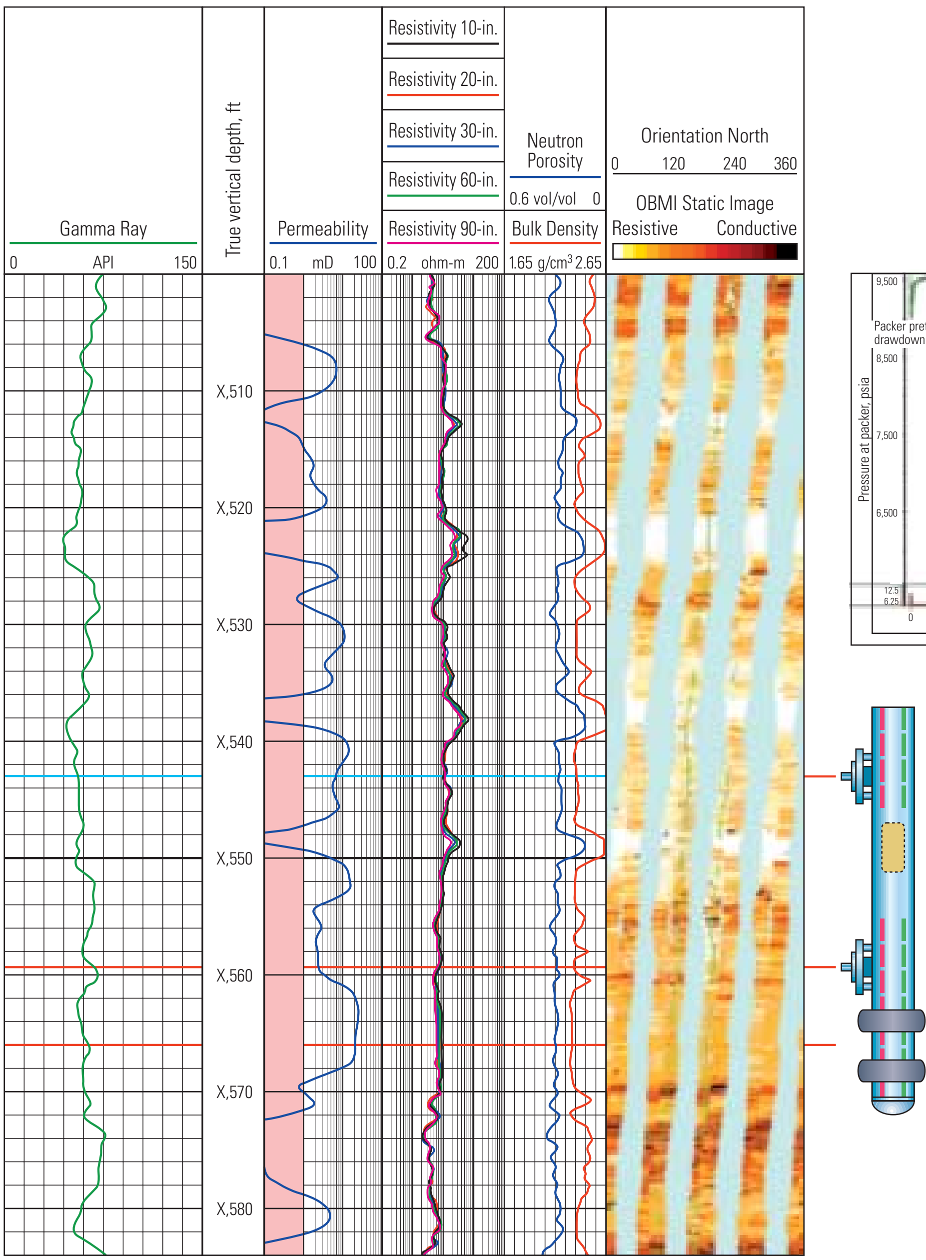
Testing Weak Sands

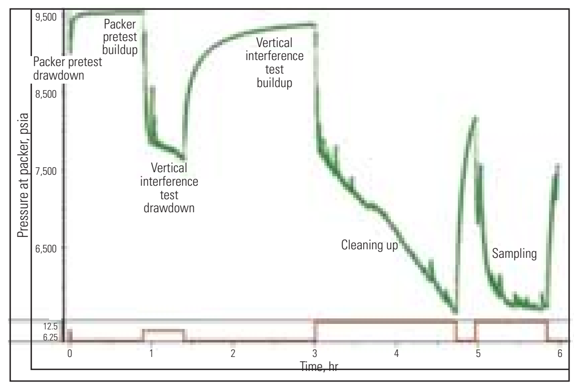
New applications for predicting sand failure continue to emerge with the growing understanding of the relationship between stresses, reservoirs and completions. Operators evaluating deepwater wells in the Gulf of Mexico rely on a variety of downhole measurements to determine reservoir characteristics, potential reserves, required production facilities and asset-development strategies. In many deepwater fields, the MDT tool has become a crucial provider of important reservoir information. Using this device, an operator can determine reservoir pressure and permeability, evaluate whether the reservoir is damaged, and collect and analyze representative fluid samples.[33]

In one of its many configurations, the MDT tool deploys a small packer and probe device that presses against the borehole wall, isolating the probe from hydrostatic pressure so that formation pressure can be measured. In weak or unconsolidated formations, the probes can become clogged, hindering testing and sampling. Depending on the specific well and reservoir, a dual-packer assembly may be preferable in weak reservoirs to eliminate the clogging problem and because the operator can control the drawdown pressure during testing to prevent formation collapse. Moreover, the larger volume of investigation between the two packers yields more representative test results.

In the deepwater Trident Gulf of Mexico prospect, water depths reach 9,800 ft [2,990 m] and operating conditions are harsh. Unocal Corporation used the MDT probe to measure reservoir pressure and to take fluid samples on two wells, Trident Well 1 and Trident Well 2. However, because many of the Wilcox zones are laminated and have low permeability, it was difficult to acquire representative test data and fluid samples using the MDT probe. Unocal investigated the dual-packer assembly for use on the next well, Trident Well 3. To fully exploit the dual-packer capability and reduce risk of formation collapse, Unocal asked Schlumberger experts to perform sand-failure analyses on the first two wells to determine the critical drawdown pressures in the reservoir section prior to running the MDT dual packers in Well 3. The Wilcox G zone in Trident Well 1 was identified as potentially weak, and could fail under too much drawdown during MDT testing (previous page, bottom).

Sand-prediction modeling was not possible on the third well because DSI data were not acquired. Because the Unocal asset team was confident in the correlation between wells, the critical drawdown pressures from the first two wells were used to design MDT tests in Well 3. With the drawdown limits defined for each Wilcox zone, the MDT dual packer was positioned and the pressure tests and sampling were conducted accordingly (left). During the testing,



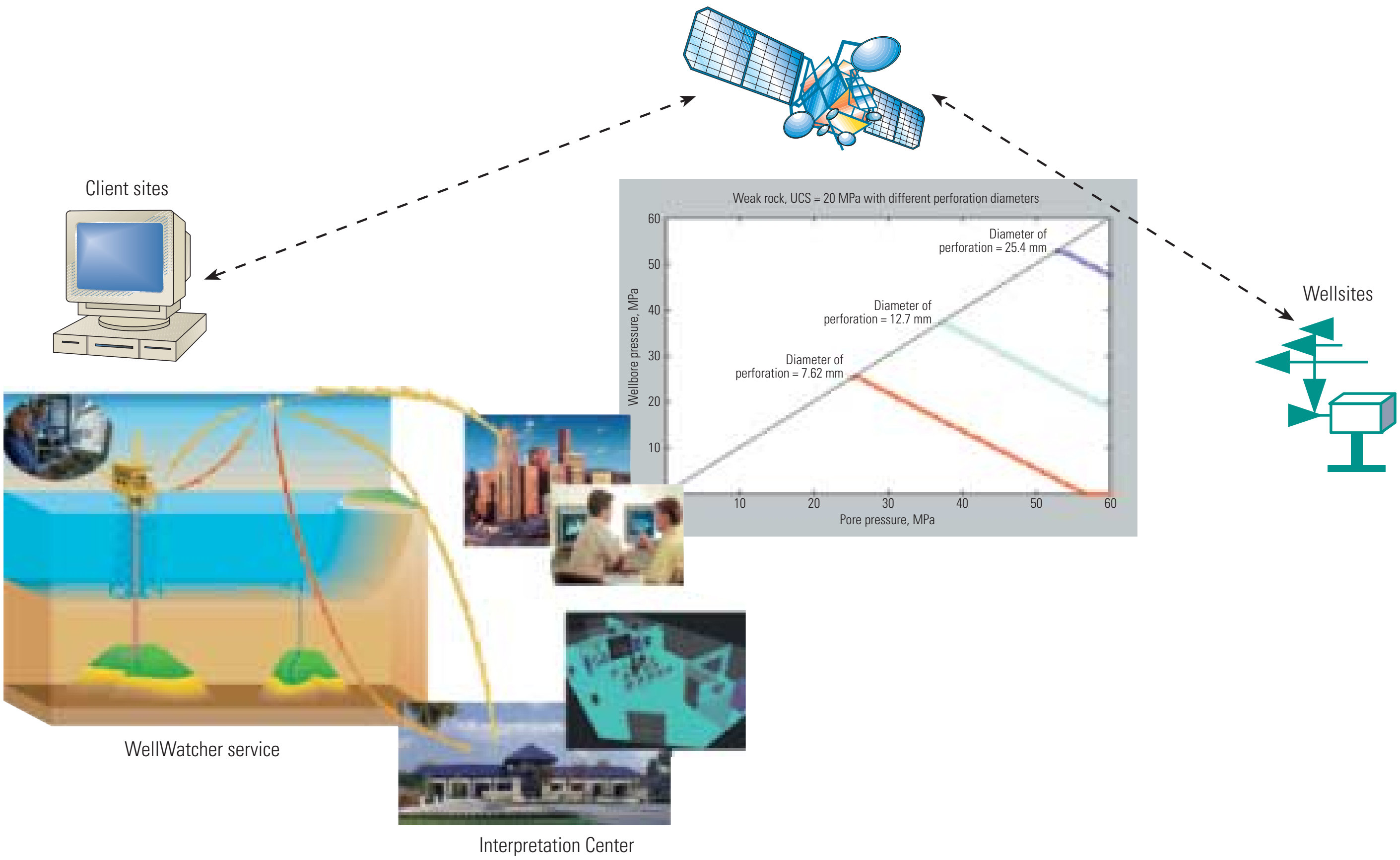


< MDT testing in the Wilcox G zone. Well-log data, including borehole image data, are displayed with the MDT test and sampling configuration (*left*). The pressure at the dual-packer module was recorded during the MDT tool testing and sampling sequence, and shows that the total drawdown was kept below the limits that were established by sand-prediction modeling (*above*). The testing and sampling operations were successful and provided Unocal with important data to help characterize the Wilcox reservoirs for future development.

33. Betancourt S, Fujisawa G, Mullins OC, Carnegie A, Dong C, Kurkjian A, Eriksen KO, Haggag M, Jaramillo AR and Terabayashi H: "Analyzing Hydrocarbons in the Borehole," *Oilfield Review* 15, no. 3 (Autumn 2003): 54–61.

Ayan C, Hafez H, Hurst S, Kuchuk F, O'Callaghan A, Peffer J, Pop J and Zeybek M: "Characterizing Permeability with Formation Testers," *Oilfield Review* 13, no. 3 (Autumn 2001): 2–23.

Badry R, Fincher D, Mullins O, Schroeder B and Smits T: "Downhole Optical Analysis of Formation Fluids," *Oilfield Review* 6, no. 1 (January 1994): 21–28.



^ Real-time monitoring and control. The negative effects of producing sand and the impact of sand-control efforts can be observed by various downhole and surface measurements. In today's connected oil field, massive amounts of data can be transmitted and sent directly to asset teams and Schlumberger experts for interpretation. The data can be used to update and verify sand-prediction models and reservoir simulators, and to facilitate complete and real-time production optimization.

the MDT drawdown pressures were kept within safe limits, as defined by the sand-failure analysis.

In combination with the dual packer, two other MDT probes were positioned above the dual-packer module to conduct vertical interference tests. These tests determined vertical permeability along with the standard horizontal permeability. The MDT operations were completed successfully and safely, with no evidence of sand failure. Armed with the MDT test results and samples, Unocal is now better prepared to exploit the Wilcox reservoirs in the Trident prospect.

Monitoring Sand Production

Determining the critical drawdown for various stages of reservoir depletion at which wellbore or perforation failure begins to occur is a primary function of the 3D sand-prediction tool. An important element of controlling the extent of sand production is managing the pressure drawdown and production rate throughout the life of a well. Monitoring sand-production rates helps optimize production rates, calibrate models, improve sand-control methods and assess the need for remedial work. This practice is central to proper reservoir management. But how do producing companies know if their sand-exclusion and sand-prevention efforts are paying off, or whether and when remediation is required?

Several methods are used to monitor sand production, and the success of these depends on the extent of the problem and the nature of the well and the completion. Surface-detection methods use sensors located at strategic positions in flowlines. For example, nonintrusive ultrasonic sensors that detect particles colliding with the interior pipe wall can be installed after bends in subsea gathering lines. Over time, these recordings can be used to determine whether sand production is increasing or decreasing, and can facilitate the estimation of hardware erosion.

Periodic downhole measurements help evaluate the effectiveness of sand-prevention methods over time. For example, production logs or well tests record pressure and flow-rate data to evaluate damage to the completion. Gravel-pack characterization can be accomplished using one or a combination of wireline measurements, including RST Reservoir Saturation Tool, CHFR Cased Hole Formation Resistivity, TDT Thermal Decay Time and CNL Compensated Neutron Log data. These devices allow completion and production engineers to locate the top of a gravel-pack completion and determine its coverage and quality.[34]

Monitoring the effects of sand production on a more permanent basis is accomplished by installing downhole sensors that record bottom-hole flowing pressure and temperature, offering real-time monitoring and control capabilities (previous page).[35] Real-time data from downhole, subsea and surface sensors can be delivered using the InterACT real-time monitoring and data delivery system to update modeling and simulation tools, such as ECLIPSE reservoir simulation software.

When Reservoirs Fail

Many completed and producing wells are experiencing sanding problems. Sand production can be relentless, with damaging effects on production rates and hardware. Early detection through monitoring can detect problems and prompt intervention before problems become severe. However, sometimes catastrophes occur unexpectedly and result in total well failure and a need for intervention. When intervention is necessary, comprehensive sand-management practices help determine the best action.

When appropriate data—production, well-test, core and log data—are coupled with sand-production and well-history information, the need for, and the value of, remediation and production-enhancement efforts can be evaluated. In wells with multizone completions, proprietary Schlumberger production-allocation software allocates production for each zone using production-log data. This allows engineers to evaluate each zone separately, making remedial treatments more selective.

In hydraulically fractured wells, proprietary ProFIT production analysis software helps determine fracture properties so that problems that limit fracture effectiveness can be diagnosed and remedied. Lastly, ProCADE software allows the analysis of well-production data to determine near-wellbore reservoir properties and to predict well performance as the completion scenarios change. These powerful software tools can predict the impact of remedial efforts to gauge both the economics and risks.

Well-intervention techniques vary in type and cost. An operator may choose a screenless method that does not require a rig, such as adding perforations, reperforating or hydraulic-fracturing techniques.[36] In some cases, vent screens can be installed without a rig. Major operations requiring a rig, like gravel packing or installing expandable screens, may be needed to achieve the best result, but these operations add costs.

When well economics justify recompletions, many sand-exclusion and sand-prevention methods again become viable options. For this reason, recompletions mark a new opportunity for operators and service providers to incorporate the informed decision-making process associated with thorough sand-management practices.

The Sands of Time

Sophisticated sand-screen and gravel-packing tool designs have drastically improved the sand-exclusion process, adding life to wells and reserves to assets. A new sand-exclusion system called expandable sand screens represents a fundamental shift in methodology. As part of the true monobore, or monodiameter, vision, expandable completions provide an efficient, single-trip alternative by expanding out to the borehole wall to reduce the annular space, thereby reducing annular flow, maximizing borehole volume and stabilizing the borehole wall. The technology eliminates the need for other tubulars and gravel packing, and it potentially offers higher productivity than cased-hole completions. While there have been mixed results with expandable-screen completions, the technology continues to evolve rapidly, and so far, its applicability has primarily been in horizontal wells that produce from well-sorted sandstone reservoirs.

Technological advances across all facets of sand management—prediction, prevention, monitoring and remediation—reflect the scale of the problem and the importance of solutions. Modeling tools that predict when reservoir sandstones will fail help E&P companies address problems downhole by preventing sand failure using screenless methods or by impeding the migration of sand into the flowstream. Schlumberger continues the quest to more fully understand perforation and borehole geomechanics, and to continue to develop innovative perforating, fracturing and sand-control completion solutions.

The ability to predict surface sand volumes accurately would be helpful. However, this remains a daunting challenge, especially in highly deviated and horizontal wells, because it requires that all modes of sand transport be considered. Moreover, there are added complexities in accounting for completion types and for varying flow regimes. Improving sand-monitoring techniques and learning how to better exploit monitoring data in models and simulators may be a more practical approach.

As with other oilfield challenges, addressing sand-production issues will require the collaboration of experts, the development of effective and efficient processes, and the appropriate use of technologies. Producing hydrocarbons from weak reservoirs is a tricky business because the unknowns outweigh the knowns, but the balance is clearly tipping towards more production with less sand. —MGG

34. Carlson et al, reference 7.
    Olesen J-R, Hudson TE and Carpenter WW: "Gravel Pack Quality Control by Neutron Activation Logging," paper SPE 19739, presented at the 64th SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, October 8–11, 1989.
35. Al-Asimi M, Butler G, Brown G, Hartog A, Clancy T, Cosad C, Fitzgerald J, Navarro J, Gabb A, Ingham J, Kimminau S, Smith J and Stephenson K: "Advances in Well and Reservoir Surveillance," *Oilfield Review* 14, no. 4 (Winter 2002/2003): 14–35.
36. Acock et al, reference 11.