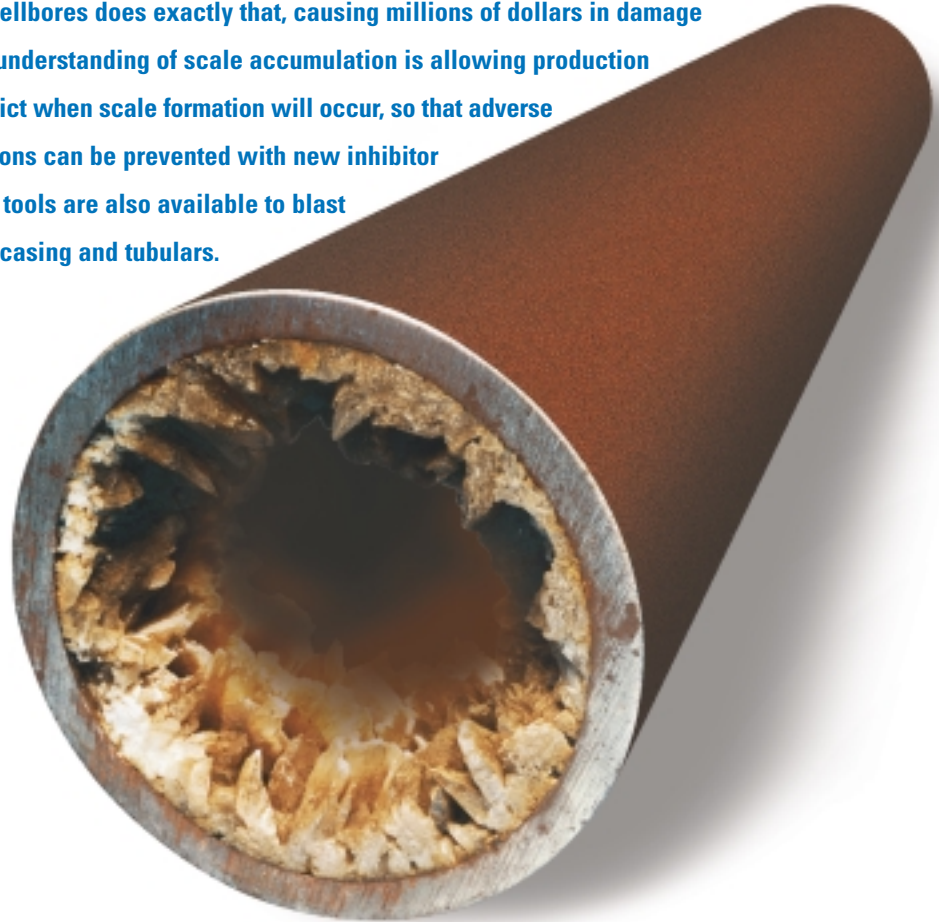


Fighting Scale—Removal and Prevention

Imagine an oilfield menace that can smother a productive well within 24 hours. The buildup of scale inside wellbores does exactly that, causing millions of dollars in damage every year. New understanding of scale accumulation is allowing production engineers to predict when scale formation will occur, so that adverse operating conditions can be prevented with new inhibitor techniques. New tools are also available to blast scale away from casing and tubulars.



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1. Brown M: "Full Scale Attack," *REview*, 30 The BP Technology Magazine (October-December 1998): 30-32.

Few production problems strike fear into the hearts of engineers the way scale can. Scale is an assemblage of deposits that cake perforations, casing, production tubing, valves, pumps and downhole completion equipment, thereby clogging the wellbore and preventing fluid flow. Scale, just like the scale found in home plumbing or tea kettles, can be deposited all along water paths from injectors through the reservoir to surface equipment. Most scale found in oil fields forms either by direct precipitation from the water that occurs naturally in reservoir rocks, or as a result of produced water becoming

oversaturated with scale components when two incompatible waters meet downhole. Whenever an oil or gas well produces water, or water injection is used to enhance recovery, there is the possibility that scale will form. In some areas, such as the North Sea and Canada, where entire regions are prone to scale, it is recognized as one of the top production problems.

Scale can develop in the formation pores near the wellbore—reducing formation porosity and permeability. It can block flow by clogging perforations or forming a thick lining in production tubing (above). It can also coat and damage downhole completion equipment, such as safety

<Scale in production tubing. Calcium carbonate scale growth in production tubing here obstructs more than 40% of the flowing area of the tubing and prevents access to lower sections by well-remediation tools.

valves and gas-lift mandrels. The effects of scale can be dramatic and immediate: in one North Sea well in the Miller field, engineers were shocked to see production fall from 30,000 B/D [4770 m³/d] to zero in just 24 hours.¹ The costs can be enormous also. Curing scale problems costs the industry hundred of millions of dollars per year in lost production. Until recently, ways to treat the problem were limited and sometimes ineffective. When scale forms, a fast, effective removal technique is needed. Scale-removal methods involve both chemical and mechanical approaches, each with its own niche—depending on the location of the scale and its physical properties.

Some mineral scales, such as calcium carbonate [CaCO₃], can be dissolved with acids, while most others cannot. Sometimes tar-like or waxy coatings of hydrocarbons protect scale from chemical dissolvers. Accumulated solid layers of impermeable scale can line production tubing, sometimes completely blocking it, and are less easily removed. Here, mechanical techniques or chemical treatments are traditionally used to cut through the scale blockages. Nevertheless, common hard scales, such as barium sulfate [BaSO₄], are extremely resistant to both chemical and mechanical removal. Before recent developments in scale-removal technology, operators with hard-scale problems in their production tubing were often forced to shut down production, move in workover rigs to pull the damaged tubing out of the well, and either treat for scale at the surface or replace the tubing.

In this article, we review the physical causes of scale buildup during oil production. Knowing the conditions that lead to scaling and when and where it occurs helps in understanding how to remove scale and in designing intervention treatments to restore long-term well productivity. Then, we survey the chemical and mechanical techniques used in scale removal—including the latest developments in jetting techniques—and examine the strengths and limitations of each approach. Finally, we look at advances in water treatments and new inhibitors that help control the delicate chemical balance to prevent scale precipitation from recurring.

>Mineral solubilities have a complex dependency on many variables including temperature (*top*), pressure (*center*) and salinity (*bottom*).

Sources of Scale

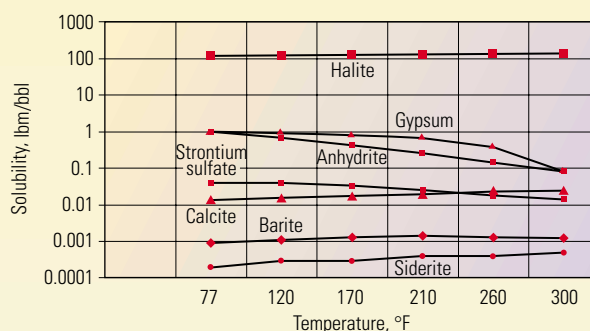
In oilfield scale, water is of primary importance, since scale will occur only if water is produced. Water is a good solvent for many materials and can carry large quantities of scaling minerals. All natural waters contain dissolved components acquired through contact with mineral phases in the natural environment. This gives rise to complex fluids, rich in ions, some of which are at the saturation limit for certain mineral phases. Seawater tends to become rich in ions that are by-products of marine life and water evaporation. Ground water and water in the near-surface environment are often dilute and chemically different from deep subsurface water associated with gas and oil.

Deep subsurface water becomes enriched in ions through alteration of sedimentary minerals. The water in carbonate and calcite-cemented

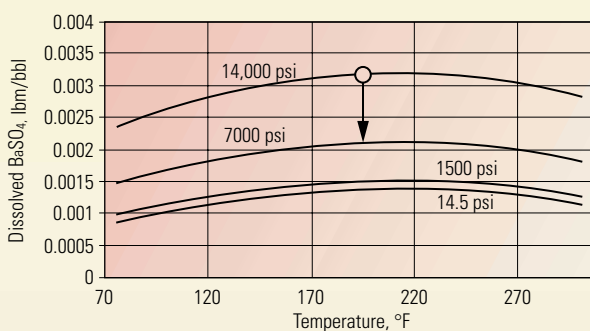
sandstone reservoirs usually contains an abundance of divalent calcium [Ca⁺²] and magnesium [Mg⁺²] cations. Sandstone formation fluids often contain barium [Ba⁺²] and strontium [Sr⁺²] cations. In reservoir fluids total dissolved solids can reach 400,000 mg/L [3.34 ppq]. The precise composition has a complex dependence on mineral diagenesis and other types of alteration encountered as formation fluids flow and mix over geological time.

Scale begins to form when the state of any natural fluid is perturbed such that the solubility limit for one or more components is exceeded. Mineral solubilities themselves have a complicated dependence on temperature and pressure. Typically, an increase in temperature increases the water solubility of a mineral. More ions are dissolved at higher temperatures (*below*). Similarly, decreasing pressure tends to decrease

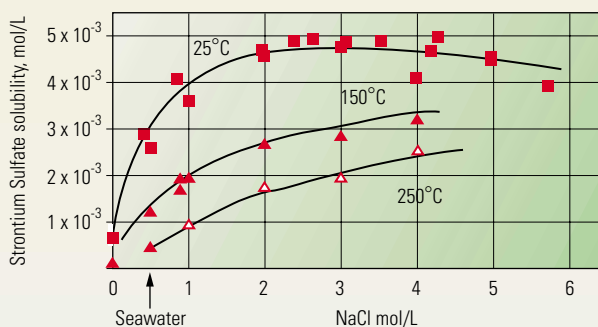
Mineral solubilities versus temperature



Minerals solubilities versus pressure

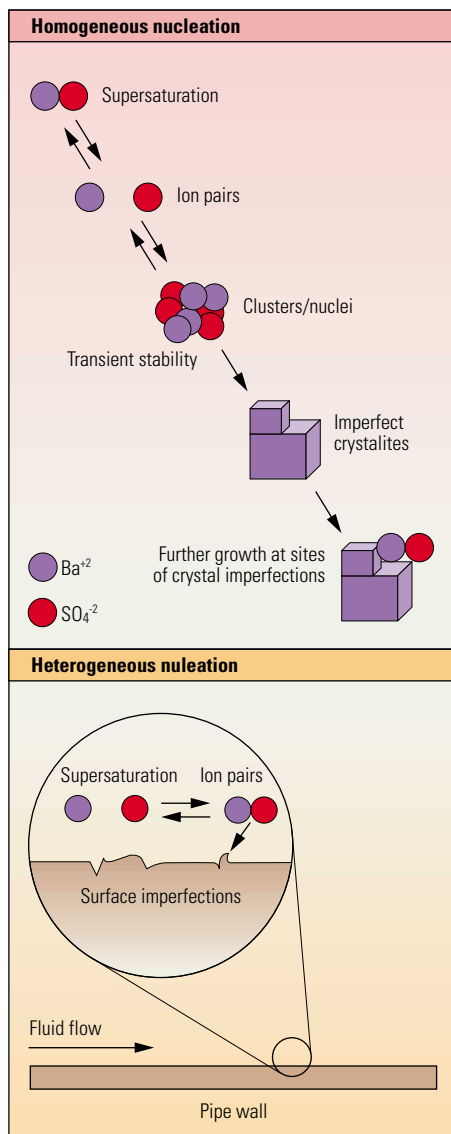


Minerals solubilities versus salinity



solubilities and, as a rule-of-thumb, the solubility of most minerals decreases by a factor of two for every 7000-psi [48-MPa] decrease in pressure.

Not all minerals conform to the typical temperature trend; for example, calcium carbonate shows the inverse trend of increasing water solubility with decreasing temperature. The solubility of barium sulfate increases by a factor of two in the temperature range 25°C to 100°C [77° to 212°F] and then decreases by the same magnitude as temperatures approach 200°C [392°F]. This trend is itself influenced by the background brine salinity.



▲ Nucleation processes. Scale growth starts in supersaturated solutions with ion pairs forming single crystals in solution, called homogeneous nucleation (*top*). Scale can also grow on preexisting surface defects—such as rough spots on the liquid-tubing surface, called heterogeneous nucleation (*bottom*).

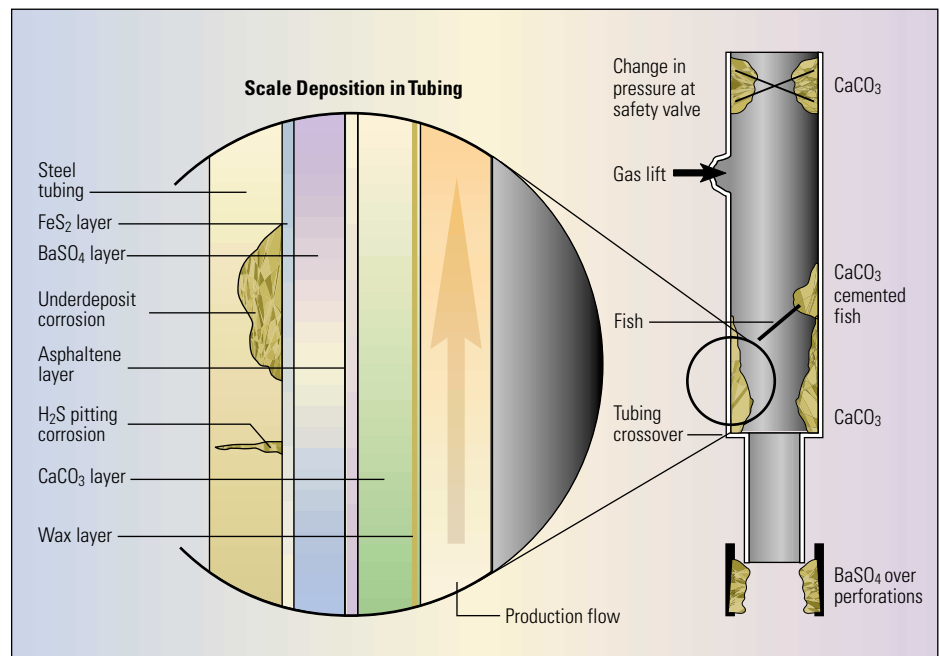
An additional complexity is the solubility of carbonate minerals in the presence of acid gases such as carbon dioxide [CO₂] and hydrogen sulfide [H₂S]. Carbonate solubility increases as fluid acidity increases, and CO₂ or H₂S at high pressure supply significant acidity. Consequently, formation waters, in contact with both carbonate rock and acid gases, can be rich in dissolved carbonate. This trend has a complex nonlinear dependence on brine composition, temperature and the pressure of the gas above the liquid phase; this gas pressure effect is orders of magnitude greater than the normal effect of pressure on the solubility of a mineral. Generally, as pressure falls, CO₂ leaves the water phase causing the pH to rise—leading to calcite scale formation.

Forming Scale

Although the driving force for scale formation may be a temperature or pressure change, outgassing, a pH shift, or contact with incompatible water, many produced waters that have become oversaturated and scale-prone do not always produce scale. In order for a scale to form it must grow from solution. The first development within a saturated fluid is a formation of unstable clusters of atoms, a process called homogeneous nucleation (*left*). The atom clusters form small seed crystals triggered by local fluctuations in the equilibrium ion concentration in supersaturated solutions. The seed crystals subsequently

grow by ions adsorbing onto imperfections on the crystal surfaces—extending the crystal size. The energy for seed crystal growth is driven by a reduction in the surface free energy of the crystal, which decreases rapidly with increasing radius after a critical radius is exceeded. This implies that large crystals favor continuing crystal growth, and also implies that small seed crystals may redissolve.² Thus, given a large enough degree of supersaturation, the formation of any seed crystal will encourage an increase in the growth of scale deposits. The seed crystal, in effect, is a catalyst for scale formation.

Crystal growth also tends to initiate on a preexisting fluid-boundary surface, a process called heterogeneous nucleation. Heterogeneous nucleation sites include surface defects such as pipe surface roughness or perforations in production liners, or even joints and seams in tubing and pipelines. A high degree of turbulence can also catalyze scale deposition. Thus, the accumulation of scale can occur at the position of the bubblepoint pressure in the flowing system. This explains why scale deposits rapidly build on downhole completion equipment. Through this understanding of nucleation phenomena, scale inhibitors—discussed later—have been developed that use chemicals specifically designed to poison the nucleation and growth stages of scale formation and reduce the rate of scale formation to almost zero.



▲ Scale in tubing. The location of scale deposits in tubing can vary from downhole perforations to the surface where it constrains production through tubing restrictions, blocked nipples, fish, safety valves and gas-lift mandrels. Scale is often layered and sometimes covered with a waxy or asphaltene coating (*insert*). Pitting and corrosion on steel can develop under the scale due to bacteria and sour gas, diminishing steel integrity.

Identifying Scale

Identifying the location and composition of the scale deposit is the first step in designing a cost-effective remediation program.

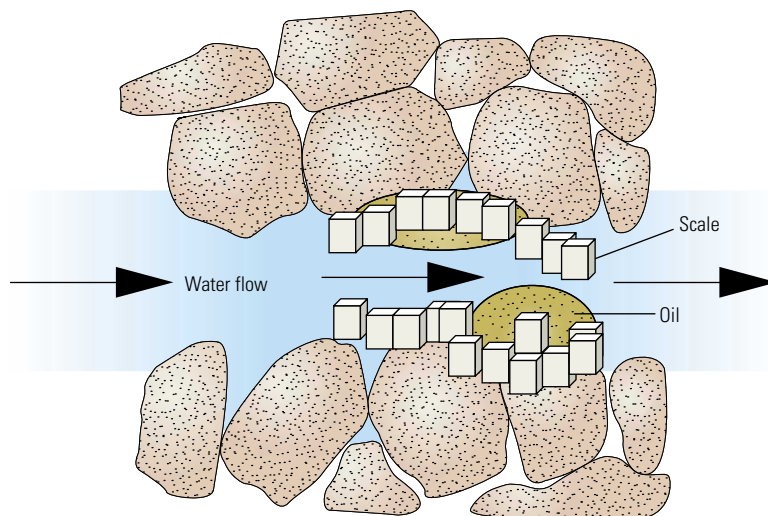
Production tubing and surface equipment—

Scale in production tubing may occur as a thick layer adhering to the inside of the tubing. It is often centimeters thick and has crystals up to 1 cm or larger. The primary effect of scale growth on tubing is to lower the production rate by increasing the surface roughness of the pipe and reducing the flowing area. The driving pressure therefore goes up and the production goes down. If mineral growth increases, then access to lower sections of the well becomes impossible, and ultimately the growth blocks production flowing through the tubing (previous page, bottom right). Tubing scale varies in chemical composition, being composed of layers of scale deposited during the well's history. Often, scales include asphaltene or wax layers, and the layers of scale that are closest to the tubing may contain iron sulfides, carbonates or corrosion products.

*Near-wellbore matrix—*The carbonate or sulfate scale that is typical of the near-wellbore region has a finer particle size than tubing scale, on the order of microns rather than centimeters. It blocks gravel packs and screens as well as matrix pores. Near-wellbore scale commonly forms after long periods of well shut-in because crossflow mixes incompatible waters from different layers. Such scale is thought of as skin (above right). Removal by chemical dissolvers or acids can increase production rates dramatically.

*Injector wells—*Scale damage to injection wells is usually caused by temperature-activated autoscaling of the injection water. In addition, incompatible mixing can occur in the near wellbore when injection water contacts either natural formation water or completion brine (right). This problem is limited to the early stages of injection, when injection water is contacting incompatible water in the near-wellbore region. Scale formed here can decrease the permeability of the formation and reduce the effectiveness of the water-flood strategy.

*Detecting scale—*Physical evidence of scale exists as samples of tubing scale or X-ray evidence from core analysis. Gamma ray log interpretation often indicates barium sulfate scale since naturally radioactive radium Ra^{226}



▲Matrix damage. Scale deposition restricts the flow of fluids through the formation, resulting in a loss of permeability.

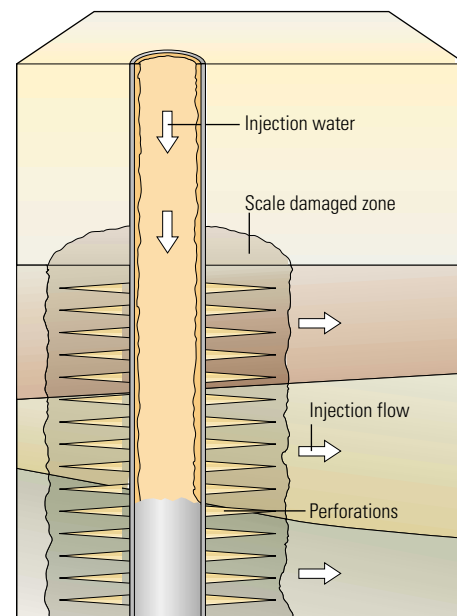
precipitates with this scale.³ As much as a 500-API increase in gamma ray activity over natural background has been seen in many cases.

Evaluating production using NODAL analysis can indicate tubing scale if a well suddenly demonstrates tubing constraints that were not present during early production. In theory, NODAL analysis can indicate scale in matrix through the identification of increasing reservoir constraints on production, although this is difficult to distinguish from other forms of formation damage.

The onset of water production is often a sign of potential scale problems, especially if it coincides with simultaneous reduction in oil production. Normally, operators track water chemistry and in particular the dissolved ion content of the produced water. Dramatic changes in the concentrations of scaling ions, such as Ba^{+2} or sulfate $[SO_4^{2-}]$, that coincide with reduced oil production and increased water cut, can signal that injection water has broken through and scale is beginning to form. Inspection of the response to previous chemical interventions, such as acid treatments, can give weight to such interpretations.

Early warning of scaling conditions would be valuable to operators, since wells can scale up within 24 hours or less. Wells with intelligent completions and permanent monitoring systems are being designed to detect changes in water chemistry. Downhole scale sensors and permanent monitoring applications are areas of active research. For example, BP Amoco initiated an integrated scale management system that uses a downhole electrochemical sensor sensitive to pH and chloride ion concentrations along with temperature, pressure and multiphase flow measurements to detect potential carbonate buildup and help regulate chemical dosages for scale control.⁴

*Chemical modeling—*Chemical models are now available to predict the nature and extent of scaling from detailed fluid conditions. These models predict phase equilibrium using thermodynamic principles and geochemical databases. All rely on basic input data such as elemental-concentration analysis, temperature, pressure and gas-phase compositions. These programs are designed to predict the effect of perturbations such as incompatible mixing or changes in temperature and pressure.



▲Injection-well damage. Autoscoring of injection water can cause scale buildup and create restrictions in the tubing. Calcium carbonate can precipitate as a result of increased temperature and pressure, leading to deposition and damage near the wellbore, particularly in HPHT wells. Incompatible mixing of injection water with formation water also leads to damage early in the injection program.

2. Richardson SM and McSweeney HY: *Geochemistry: Pathways and Processes*. Englewood Cliffs, New Jersey, USA: Prentice-Hall, Inc., 1989.

3. Bamforth S, Besson C, Stephenson K, Whittaker C, Brown G, Catala G, Rouault G, Thérion B, Conort G, Lenn C and Roscoe B: "Revitalizing Production Logging," *Oilfield Review* 8, no. 4 (Winter 1996): 44-60.

4. Snieckus D: "Tipping the Scales," *Offshore Engineer* (September 1999): 117.

Many scale-prediction programs are now available as public domain software and a limited number of commercial computer programs tailored specifically to the simulation of oilfield brine chemistry. These programs range from spreadsheet models to highly developed geochemical models designed to simulate fluid and chemical transport in porous formations.⁵

Such simulators can be used to predict scaling problems far into the future, using scenarios of reservoir performance and expected water breakthrough. In fact, for new reservoirs that have no history of scaling problems, chemical models are the only available predictive tools. Still, simulators require highly accurate chemical composition data for virgin reservoir fluids and injection waters. These are rarely available, but can be collected to provide more accurate predictions of scale formation.

Common Scaling Scenarios

Four common events typically encountered in hydrocarbon production give rise to scale.

Incompatible mixing—Mixing incompatible injection and formation waters can cause scale formation. Seawater is often injected into reservoirs during secondary and enhanced-recovery

waterflooding operations. Seawaters are typically rich in SO_4^{2-} anions with concentrations often above 2000 mg/L [0.02 ppb], while formation waters contain divalent cations Ca^{+2} and Ba^{+2} . Fluid mixing in the near-wellbore matrix generally produces new fluids with combined ion concentrations that are above the solubility limits for sulfate minerals. Calcium sulfate [CaSO_4] scale forms in limestone formations, and barium sulfate [BaSO_4] and strontium sulfate [SrSO_4] scales form in sandstone formations (below). If these scales form in the formation, they are difficult to remove chemically and impossible to remove mechanically. Incompatible water mixing can also occur in tubing, producing scales that are accessible to both chemical and mechanical removal.

Autoscaling—A reservoir fluid experiences changes in temperature and pressure as it is produced. If such changes take the fluid composition beyond the solubility limit for a mineral, it will precipitate as scale—this phenomenon is called autoscaling or self-scaling. Sulfate and carbonate scales can precipitate as a result of pressure changes within the wellbore or at any restriction downhole. Sodium chloride scale (halite) forms in a similar way from highly saline brines

undergoing large temperature drops. Water can carry 100 lbm/bbl [218 kg/m³] of halite at 200°C, but only 80 lbm/bbl [174 kg/m³] at surface temperatures. Halite can precipitate at the rate of 20 lbm for each barrel of water produced, leading to many tons of scale every day in a single well producing water at a rate of 1000 B/D [159 m³/d].

Another serious problem occurs when carbonate scales precipitate from produced fluids containing acid gases. Reduction in pressure during production outgasses the fluid, which raises pH and causes scale deposition. The deposition of carbonate can extend from the near-wellbore matrix, along tubing and into surface equipment as the produced water continuously changes in pressure and temperature.

For carbonate scales, temperature effects often work against pressure effects. For example, the pressure drop at the point of entry into the wellbore can lead to matrix scale. As the fluid progresses up the tubing to surface temperatures and wellhead pressure, the resulting temperature drop may override the pressure effect, reducing scale formation in the tubing. On the other hand, subsequent release of pressure from the wellhead to surface can lead to massive deposits of scale in surface equipment and tubing.

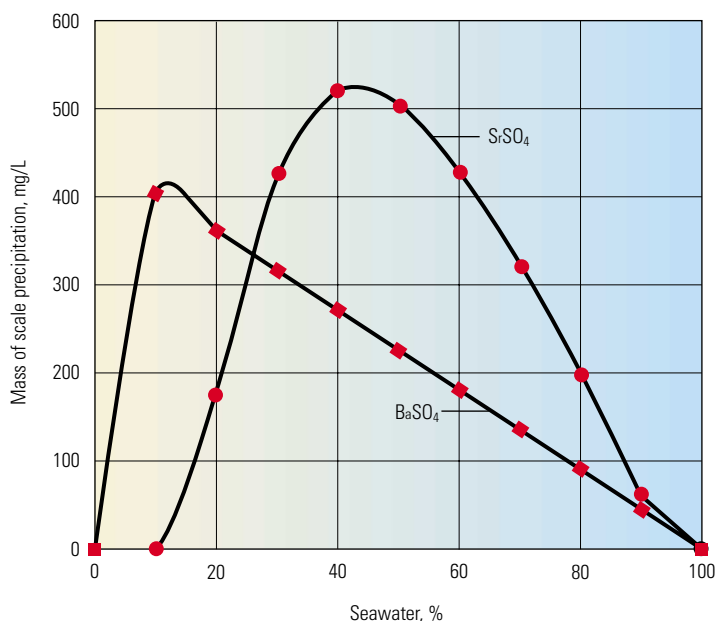
Evaporation-induced scale—Scale formation is also associated with the simultaneous production of hydrocarbon gas and formation brine (wet gas). As the hydrostatic pressure in production tubulars decreases, the volume of the hydrocarbon gas expands and the still hot brine phase evaporates. This results in dissolved ions being concentrated in excess of mineral solubilities in the remaining water. This is a common cause of halite scaling in high-pressure, high-temperature (HTHP) wells, but other scales may also form this way.

Gas flood—Flooding a formation with CO_2 gas for secondary recovery can result in scale deposition. Water containing CO_2 becomes acidic and will dissolve calcite in the formation. Subsequent pressure drops in the formation surrounding a producing well can cause CO_2 to break out of solution and cause carbonate scale to precipitate in the perforations and in formation

Brine Composition of Two Different Waters

Ion species	Formation water, ppm	Seawater, ppm
Sodium	31,275	10,890
Potassium	654	460
Magnesium	379	1368
Barium	269	0
Strontium	771	0
Sulfate	0	2960
Chloride	60,412	19,766
Calcium	5038	428

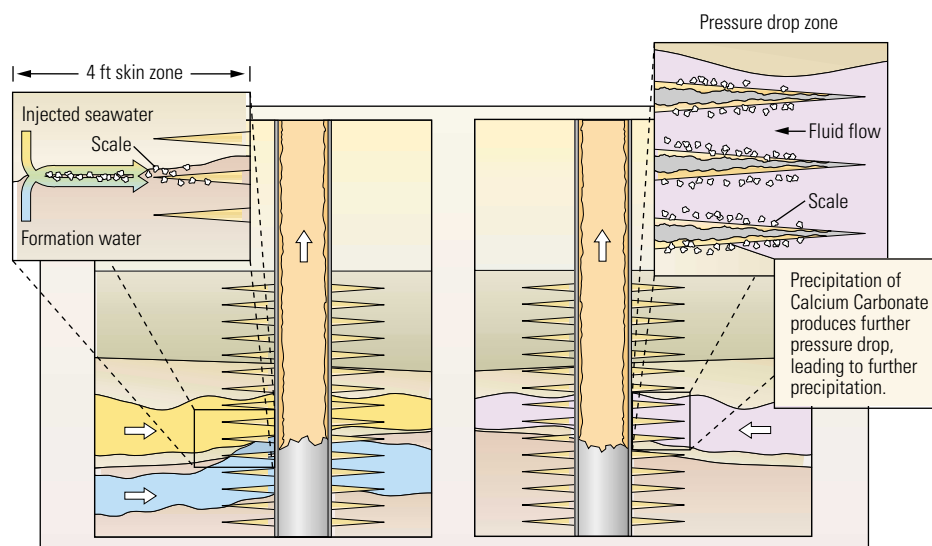
>Scale from incompatible waters. The table (top) shows typical differences in ion concentrations found in formation water and seawater. The graph (bottom) shows the amount of scale that precipitates from different mixtures of seawater and formation water.



5. Oddo JE and Tomson MB: "Why Scale Forms and How to Predict It," *SPE Production & Facilities* 9, no. 1 (February 1994): 47-54.

6. Martel AE and Calvin M: *Chemistry of Metal Chelate Compounds*. New York, New York, USA: Prentice-Hall, Inc., 1952.

7. Kotlar HK, Karlstad S, Jacobsen S, and Vollen E: "An Integrated Approach for Evaluating Matrix Stimulation Effectiveness and Improving Future Design in the Gullfaks Field," paper SPE 50616, presented at the 1998 SPE European Petroleum Conference, The Hague, The Netherlands, October 20-22, 1998.



▲ Production well damage. Autoscaling can lead to problems in producing wells (right), where scale forms near the perforation throat (right insert). The pressure drop over the near-wellbore matrix can lead to runaway CaCO_3 precipitation. Mixing incompatible injection water and formation water can lead to scale precipitation in the formation matrix (left).

pores near the wellbore. The production of scale in the near-wellbore environment will cause a further reduction in pressure and even more precipitation (above). Like autoscaling, this self-generating process can completely seal perforations or create an impermeable wall between the borehole and reservoir within a few days, completely shutting down production.

Scale Removal

Scale-removal techniques must be quick, non-damaging to the wellbore, tubing or formation environment, and effective at preventing reprecipitation. Formation matrix stimulation treatments frequently employ scale dissolvers to arrest production decline. The best scale-removal technique depends on knowing the type and quantity of scale, and its physical composition or texture. A poor choice of removal method can actually promote the rapid recurrence of scale.

In tubulars, scale strength and texture play significant roles in the choice of removal technique. Strengths and textures vary from delicate, brittle whiskers or crystals with high microporosity, to rock-like, low-permeability, low-porosity layers. Scale purity affects its resistance to removal methods. Scale may occur as single-mineral phases, but is more commonly a mixture of similar, compatible compounds. Pure barium sulfate is normally of low porosity and is extremely impervious to chemical removal, and only slowly removable by most established mechanical techniques. Mixtures of barium sulfate, often with strontium sulfate, calcium sulfate or even calcium carbonate, will frequently yield to a variety of removal methods, both chemical and mechanical.

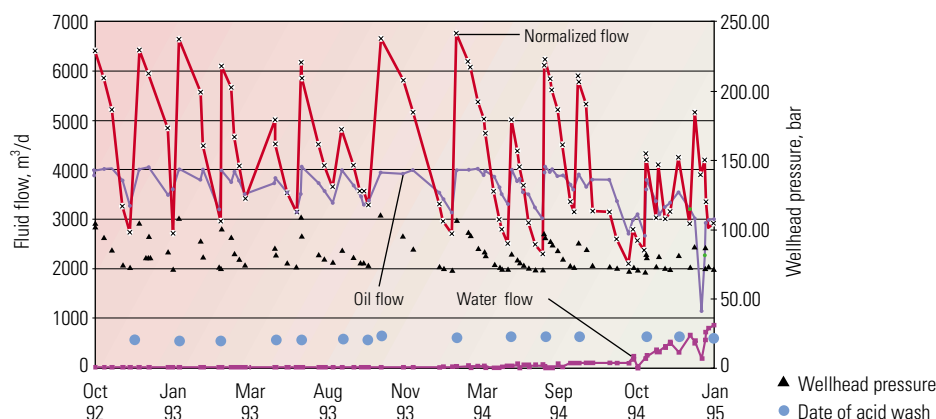
Chemical techniques—Chemical scale removal is often the first, and lowest cost approach, especially when scale is not easily accessible or exists where conventional mechanical removal methods are ineffective or expensive to deploy. For example, carbonate minerals are highly soluble in hydrochloric acid and therefore can be easily dissolved. Hard sulfate scale is more difficult because the scale has a low acid solubility. In the formation matrix, it can be treated by the use of strong chelating agents, compounds that break up acid-resistant scale by isolating and locking up the scale metallic ions within their closed ring-like structure.⁶

Most chemical treatments are controlled by how well the reagents gain access to the scale

surface. Consequently, the surface-area-to-volume ratio, or equivalently the surface-area-to-mass ratio, is an important parameter in the speed and efficiency of the removal process. Large reactant surface areas, such as porous materials, clay-like particles of extremely thin plates, and hair-like projections react quickly, since the acid or reactant volume surrounding the surface is large. Smaller surface-area-to-volume in thick, nonporous sheets of scale are slow to react with any but the strongest chemical reactants. Scale deposits in tubing exhibit such a small surface area for a large total deposited mass that the reactivity of chemical systems is usually too slow to make chemical treatment a practical removal method.

Frequently high-permeability zones in the formation—offering a path of least resistance—divert treatment fluids, and hinder the ability of scale dissolvers to penetrate the intervals damaged by scale. Novel techniques using dissolvers and preflushes containing viscoelastic surfactants can enhance dissolver placement. Viscoelastic surfactants form high-viscosity gels when mixed with specific brine compositions, but completely break down and become water-like in the presence of oil or hydrocarbon gas. Therefore, these viscoelastic surfactants help channel the scale dissolvers into productive oil-saturated zones, avoiding nonproductive water-saturated zones.

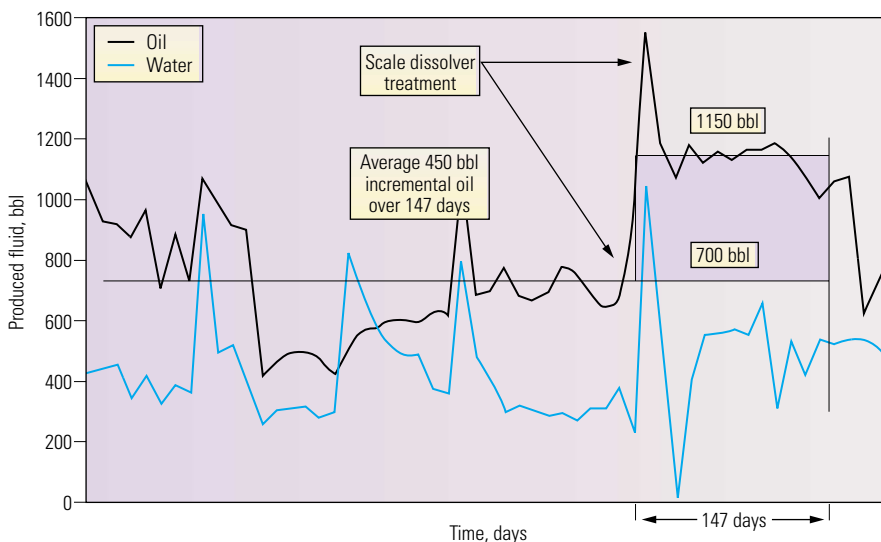
Although hydrochloric acid is usually the first choice for treating calcium carbonate scale, the rapid acid reaction may hide a problem: spent acid solutions of scale by-products are excellent initiators for reformation of scale deposits. For example, a field study evaluating matrix stimulation with acid, helped an operator in the North Sea interpret declining production rates (below).⁷ By comparing well production histories in the



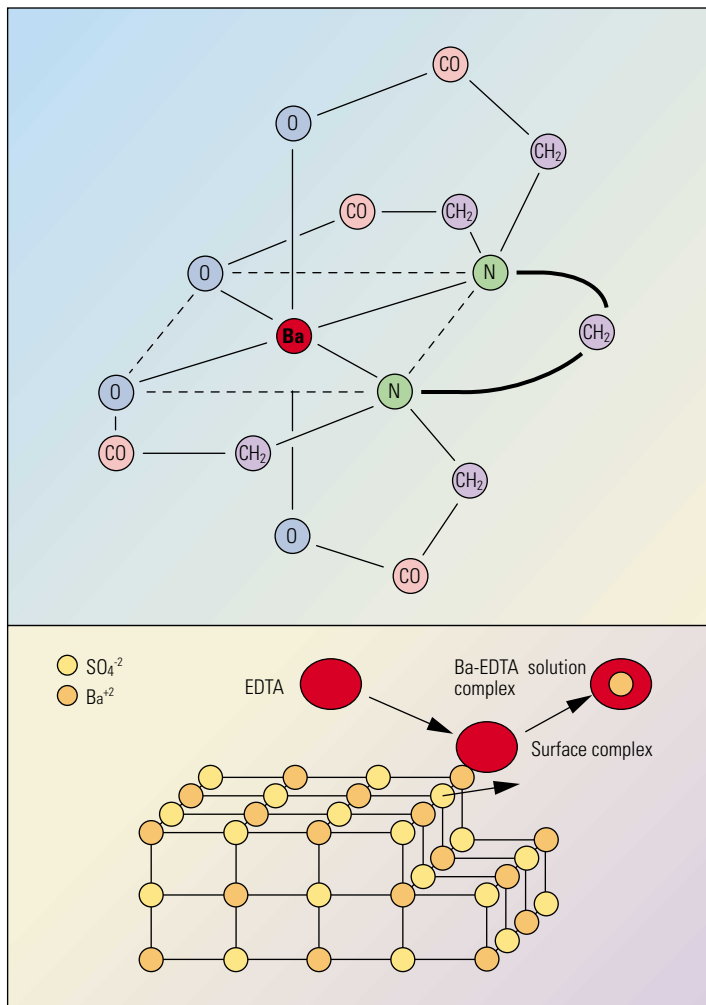
▲ Saw-tooth production profiles. A portion of the production history from one of the prolific wells in the Gullfaks field shows cyclic production impairment. The normalized flow (red curve) is a good indicator of productivity changes due to intervention efforts, because it removes the effects of choked-back production caused by surface equipment limitations. The normalized curve shows the large and immediate impact of multiple acid treatments (indicated by blue circles) and the subsequent loss in well productivity within one to three months afterwards—indicating recurring scale precipitation.

Gullfaks field before and after stimulation, engineers used NODAL analysis to determine the change in formation damage, called skin. Then, the effect of each acid treatment on different types of scale in each well was modeled using a coupled wellbore-reservoir simulator (see “Chemical Placement Simulator,” page 40). The impact of scale removal on the skin in each case was compared with the production-derived changes in skin to evaluate the type of scale and its location. The field study confirmed that carbonate reprecipitation in the gravel packs was the primary damage mechanism causing recurring production losses in the wells.

Chemicals that dissolve and chelate calcium carbonate can break this reprecipitation cycle. Ethylenediaminetetraacetic acid (EDTA) was an early candidate to answer the need for improved chemical removal, and is still used today in many forms (below). While EDTA treatments are more



▲ North Sea well production history. High skin damage in a well due to BaSO_4 and CaCO_3 scaling in the perforations and matrix near the wellbore was successfully treated, resulting in a 64% increase in oil production for more than 147 days.



▲ EDTA chelate compound. Chelating agents are used to lock up unwanted ions in solution. An EDTA molecule shares electrons from oxygen and nitrogen atoms with barium ions, forming a barium-EDTA chelate compound (top). The chelating process can help to dissolve solid barium sulfate scale (bottom).

expensive and slower than hydrochloric acid, they work well on deposits that require a chemical approach. EDTA and variations on its chemical structure are also effective in noncarbonate scale removal, and show promise for the removal of calcium sulfate and mixtures of calcium-barium sulfate.

Recently, Schlumberger developed an improved EDTA-based scale dissolver, called U105, as a cost-effective alternative for carbonate matrix stimulation. This dissolver was designed specifically for calcium carbonate, but is also effective against iron carbonate and iron oxide scales. It dissolves carbonates more slowly than hydrochloric acid and has a higher dissolving capacity than traditional organic acids, such as formic and acetic acid. Once the scale is dissolved through chelation, there is no reprecipitation. Stable at temperatures up to 250°C [482°F], it is a low-toxicity scale dissolver that is effectively noncorrosive on most steels—making the treatment extremely safe.

Other chelating agents have also been optimized especially for barium and strontium sulfate scale. For example, U104 is based on an EDTA dissolver containing chemical activators that enhance the rate of scale dissolution, and has proven effective on a wide variety of scales including calcium sulfate, calcium carbonate and mixed scales. In a typical applications these solutions are diluted with fresh water with a 6- to 24-hour soak period.

The effectiveness of this new dissolver was demonstrated on a North Sea well that had high skin damage due to scaling in the near-wellbore matrix and perforations. The scale type was identified as mixed barium sulfate and calcium carbonate. A U104 treatment was designed to bullhead, or pumped against pressure, into the formation to give an average radial displacement of 3 ft [1 m]. The treatment was overflushed with a tubing displacement of inhibited seawater, and the well was shut in for a total soak time of 18 hours, after which it was returned to production (previous page, top). Production increased 450 BOPD [72 m³/d] paying out all materials, pumping and lost production costs in 12 days.

Conventional mechanical methods—Mechanical solutions to remove scale deposits offer a wide array of tools and techniques applicable in wellbore tubulars and at the sandface (below). Like chemical techniques, most mechanical approaches have a limited range of applicability, so selecting the correct method depends on the well and the scale deposit. Mechanical approaches, though varied, are among the most successful methods of scale removal in tubulars.

One of the earliest scale-removal methods was an outgrowth of the use of explosives to rattle pipe and break off brittle scale. Explosives provided high-energy impact loads that could remove scale, but often damaged tubulars and

cement. Taming the explosive meant changing the type of explosive or reducing the amount of explosive load. A strand or two of the detonation cord, called a string shot, was found to be adequate.

String shots are still used today, especially as a simple diagnostic tool, when quick wireline entry and detonation during flow yield clues about the type and location of scale. Experience shows that using a few strands of cord, detonated by an electronic cap, and long enough to cover the zone of interest, is effective in removing scale blockages in perforations and thin scale films inside tubulars.

Thick scales, especially those in tubulars, are often too strong for safe explosive removal and have too little porosity for effective chemical treatments in a reasonable time frame. For these deposits, removal usually requires techniques developed for drilling rock and milling steel. Impact bits and milling technology have been developed to run on coiled tubing inside tubulars using a variety of chipping bits and milling configurations. The downhole power source is typically a hydraulic motor or a hammer-type impact tool. Motors are fluid-powered, stator and rotor combinations that turn the bit. Their power depends on fluid supply rate and motor size—smaller motors that remove scale inside tubing, typically 1¹/₁₆-in. to 1³/₄-in. diameter, provide torque from 100 to 130 ft-lbf.

Because scale is rarely deposited evenly on the tubing wall, milling power requirements vary enormously. When motors cannot supply the power needed for the bit to cut the scale, the motor stalls and the milling process stops. As a result, scale-removal rates vary with the type of scale and application, but generally range from about 5 to over 30 linear feet [1.5 to over 9 m] of scale removed from the tubular per hour of milling. The variation in milling speed depends on the match between the type of deposit and the combination of motor and mill. Experience shows that small, low-torque motors are generally more effective when run with small-tooth mills. Larger tooth mills, though more aggressive, do not spin well on irregular scale surfaces—stalling small motors. Thus, the small-tooth, less aggressive mills cut faster because they are less prone to frequent motor stalls.

Tool	Description	Clean hard bridges	Clean tubular jewelry	Other advantages	Other disadvantages
Mechanical cleaning					
Positive displacement motor and mill	Fluid-powered 'Moineau' motor and mill. Mill removes deposits by grinding.	Yes. Clean rate may be very slow.		Positive surface indication of cleaning Small cuttings make hole cleaning easier	Motor stator and mill are expensive expendables ~300°F [150°C] limit Not compatible with scale dissolvers Mill can damage tubulars
Impact hammer	Fluid powered percussion hammer. High shock forces shatter brittle deposits.	Yes. Clean rate may be very slow.		Positive surface indication of cleaning Simple, robust tool	Large cuttings size makes hole cleaning more difficult Not compatible with scale dissolvers
Chemical cleaning					
Fixed wash tool	Fixed tool with many large-diameter nozzles. Normally used only with chemical dissolvers.		Yes, if deposit is soluble.	Simple, robust tool	Most fluid power lost to circulating friction Low nozzle pressure—cannot remove inert deposits
Spinning-jetting tool	Rotational torque provided by nozzles offset from tool axis. No speed control.		Yes, if deposit is soluble.	Simple tool Complete wellbore coverage by rotating jets	Inefficient jetting due to high rpm (>5000)
Indexed-jetting tool	Nozzle head rotates ~90° when coiled tubing pressure is cycled. Head has many small-diameter nozzles to improve wellbore coverage.		✓		Requires multiple cleaning runs increasing job time and coiled tubing fatigue No surface indication of cleaning Small cleaning radius due to small nozzles
Turbine-powered jetting tool	Fluid turbine rotates nozzle with two nozzles. Eddy current brake controls rpm.		✓	Complete wellbore coverage with large cleaning ratios	Abrasives cannot be pumped through turbine Complex tool
Sonic tools	Used to create high-frequency pressure pulses that remove deposits by shock waves or cavitation.		Yes, if deposit is soluble.	Simple	Hydrostatic pressure suppresses cavitation Tools not effective in removing hard scales in lab tests
Jet Blaster tools					
Scale Blasting technique	Nozzle head rotated by two nozzles offset from tool axis. Viscous brake controls rpm.		✓	Complete wellbore coverage with large cleaning radius Positive surface indication of cleaning	
Bridge Blasting technique	Fluid-powered 'Moineau' motor and jet/mill head. Radial jets follow pilot mill.	✓	✓	Positive surface indication of cleaning	Motor stator is an expensive expendable ~300°F limit

▲Mechanical scale-removal techniques.



▲ Removing calcium carbonate scale with water jetting. The tubing was jetted with a single water jet at a rate of 2.4 in./min [1 mm/sec]. Although carbonate scale has been removed, a considerable amount remains in place.

Impact tools, such as the Baker Oil Tools Hipp Tripper tool, are reciprocating tools that work much like a small jackhammer with a rotating bit. They impact the scale at 300 to 600 times per minute and rotate about 20 times per minute, typically with a chisel or star-shaped bit. Mills cannot be used with such tools because the impacts cause excessive damage to the mill surface. These tools work best on brittle scale deposits, removing scale as quickly as 10 to 100 linear feet [3 to 30 m] per hour.

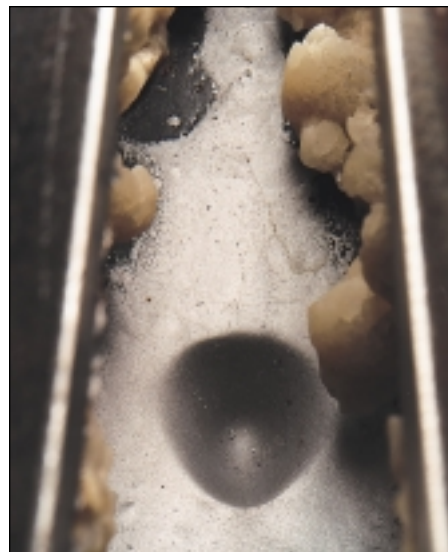
When fullbore access to scale deposits is partially blocked by physical restrictions such as decreasing tubing diameter and encroaching completion equipment, tools that can change diameter are required to remove scale below the restriction. If such equipment is not available, then a small hole—less than full tubing size—can usually be drilled through the scale below the restriction to allow increased flow. Nevertheless, a residual scale surface in the tubing encourages new scale growth and makes inhibitor treatments

> **Particle-impact tester.** A particle-impact tester was built to study and evaluate the abrasive material damage mechanism on steel tubing and scale substrate (*top*). This device can fire individual particles in excess of 450 mph [200 m/sec] that hit the surface at angles between glancing blows of 30° and perpendicular impacts. The damage from various particles can be seen in the photographs (*bottom*). Angular sand and calcite particles tend to gouge through the steel, leading to ductile failure. Round particles bounce off the steel surface. Glass beads create large, deep impact craters that eventually erode through the steel tubing. Sterling Beads particles shatter on impact with steel, creating only small pits that leave the steel undamaged.

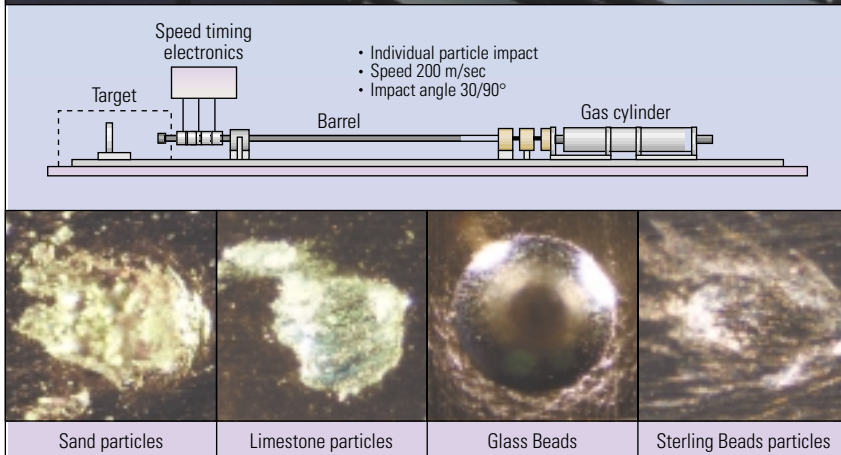
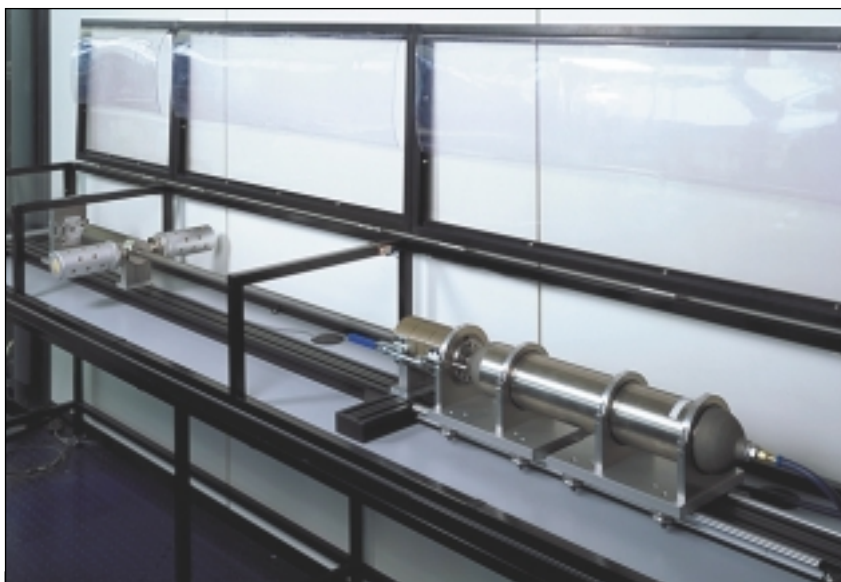
to block nucleation much more difficult. A clean, bare steel surface is more effective in preventing new scale growth.

Impact tools like motors and mills usually need fullbore access and seldom clean scale completely to the steel walls. For such partial access situations, under-reaming mills can increase the effective diameter by moving the milling blades outward in response to pump pressure and rate. Under-reaming mills are effective, but remove scale only at about half the rate of a typical mill.

Fluid-mechanical jetting methods—Downhole fluid-jetting systems, such as Halliburton's Hydroblast and BJ-NOWSCO's RotoJet system, have been available for many years to remove scales in production tubing and perforations. Such tools use multiple jet orifices or an indexed jetting head to achieve full wellbore coverage. These tools can be used with chemical washes to attack soluble deposits wherever placement is critical to prevent bullheading reagent losses. Water jetting can be effective on soft scale, such as halite, and debris or fill, but experience shows that it is less effective on some forms of medium to hard scale such as calcite and barium sulfate (*left*).



▲ Removing calcium carbonate scale with abrasive water jetting. The tubing was jetted with abrasive sand in a single water jet at a rate of 2.4 in./min [1 mm/sec]. During the test the jet was held stationary for 3 minutes, and the sand jet cut a hole nearly 80% through the tubing wall, an unacceptable level of damage.

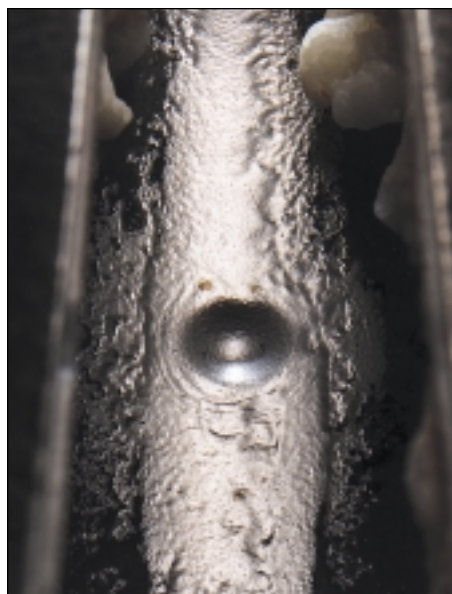


At surface pressure, water jetting removes scale by cavitation, whereby small bubbles form in the fluid jet stream. These bubbles are created by the large pressure release as fluid passes through the jet nozzle. The bubbles collapse on impact with scale, causing a forceful—almost explosive—erosive effect. Research at Schlumberger Cambridge Research, England, shows that this cavitation process is highly suppressed downhole under hydrostatic borehole pressure. Cutting rates are typically reduced by a factor of four or more. Surface pumping-pressure limitations using coiled tubing-conveyed jetting tools prevent increasing fluid pressure high enough to overcome the differential loss at the bottom.

Abrasive slurries—Adding a small concentration of solids, 1% to 5% by weight, to a water jet can drastically improve its ability to cut through scale. Water jets using abrasive sand are widely used in the construction and demolition industries for cutting reinforced concrete, and even in demilitarization for cutting live ammunitions without generating heat or an ignition source. This technique also shows superior cutting performance in calcium carbonate scale over water jetting alone ([previous page, top right](#)). Unfortunately, using abrasives such as sand can damage steel tubulars. When scale is completely removed from tubing, the abrasive jet erodes the steel as efficiently as it does the scale. Should the jetting tool stall, there is a significant risk of the abrasive jet perforating the steel tubing.

An abrasive jet that cuts scale without damaging tubing must exploit the difference in hardness between wellbore scale and the underlying steel. One of the key differences between wellbore scale and tubular steel is that while scale is brittle, steel is prone to ductile failure ([previous page, bottom](#)). A sharp sand particle will erode the surface of ductile material by a cutting and plowing action. On the other hand, a hard round particle will bounce off the surface, removing only a small volume of steel and leaving an impact crater. Scale exhibits brittle failure, so the impact of a hard particle fractures the scale and ultimately causes substrate disintegration. Scale breakdown is independent of particle shape.

8. Johnson A, Eslinger D and Larsen H: "An Abrasive jetting Removal System," paper SPE 46026, presented at the 1998 SPE/IcoTA Coiled Tubing Roundtable, Houston, Texas, USA, April 15-16, 1998.



▲Tubing cleaned with glass-bead abrasive. The tubing was jetted with glass beads in a single water jet at a rate of 2.4 in./min [1 mm/sec]. Carbonate scale has been removed. During the test the jet was held stationary for 3 minutes, and the glass beads cut a hole nearly 30% into the tubing wall.

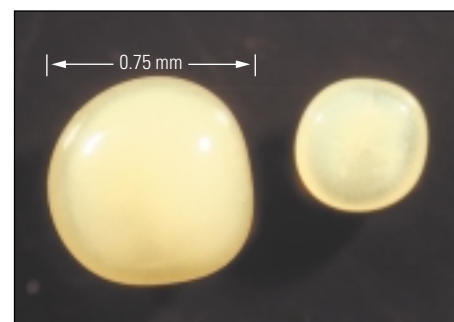
Choosing round rather than sharp, angular particles promotes scale erosion while reducing damage to steel tubulars. For example, Adams Coiled Tubing provides a glass-bead abrasive-jetting system. The jetting tool has eight stationary nozzles allowing complete radial coverage and downward pointing jets. The system is compatible with foaming fluids and effective on all types of scale. On the other hand, the craters formed by repeated impacts with glass particles can eventually lead to fatigue and failure of the steel surface ([above](#)).

Sterling Beads abrasives—Glass beads are significantly harder than the steel tubing and cause excessive tubing erosion. Reducing the hardness of the abrasive particles too much, however, renders them ineffective. Thus, the desired hardness is a compromise between minimizing damage to the steel while maximizing the scale-cutting performance. Other parameters, such as abrasive material friability, are also important. Although many spherical particles of correct hardness are available, they tend to have low durability and shatter on impact—imparting insufficient destructive energy to the substrate to remove the scale.



▲Tubing scale removed with the Sterling Beads abrasive. The tubing was jetted with Sterling Beads abrasive in a single water jet at a rate of 2.4 in./min [1 mm/sec], to remove carbonate. During the test, the jet was held stationary for 3 minutes, and less than 2% of the steel was removed from the tubing wall.

Based on experimental and theoretical study of the physical interactions between abrasive particles and typical tubing materials at Schlumberger Cambridge Research, a new abrasive material called Sterling Beads abrasive was proposed.⁸ This material matches the erosive performance of sand on hard, brittle scale materials, while being 20 times less erosive of steel, and will not damage the well if prolonged jetting occurs in one spot ([above](#)). The abrasive particles have a spherical shape, a high fracture toughness and low friability ([below](#)). The beads are soluble in acid and have no known toxicity, making cleanup operations simple.



▲Microscopic view of Sterling Beads abrasive.

Chemical Placement Simulator

A simulator can help design an effective chemical treatment. For example, StimCADE software is a coupled wellbore and reservoir stimulation program that includes a wellbore model, a reservoir model and a chemical reaction model for scale prediction. Input parameters include a comprehensive list of wellbore, formation, fluids and chemical treatment descriptions. The wellbore model solves convection-diffusion equations for fluid flow down the treatment string

(production tubing, coiled tubing or the casing) to estimate friction pressure during pumping.

In estimating the invasion of treatment fluids into the formation surrounding the wellbore, the reservoir model tracks the location of different fluid fronts in the reservoir. The chemical reaction model estimates the rate of mineral dissolution following kinetic rate laws for the solvents used and mineral species present in the formation lithology section. The net mineral

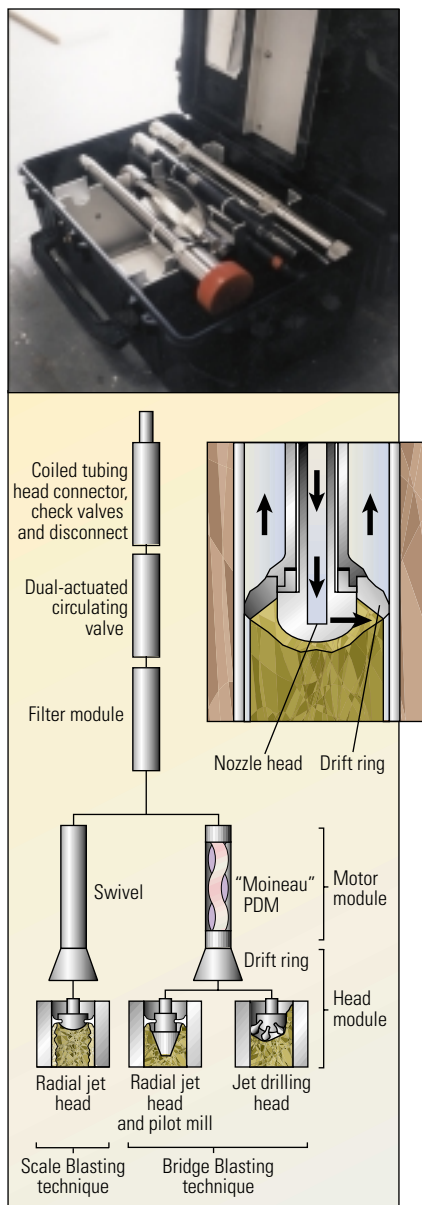
dissolution is translated into a skin reduction for each acid treatment.

Additional features include the ability to model wellbore deviation, predict effects of diverting agents on fluid-invasion profiles in the reservoir, and simulate flow of two fluids simultaneously into the well—one down tubing or coiled tubing, and one down the annulus. These features help predict the efficiency of various treatment placements.

Universal scale-removal system—Engineers at the Schlumberger Reservoir Completions Center in Rosharon, Texas, USA, developed a viscous fluid-controlled rotating head jetting tool called the Jet Blaster tool, that has jet-nozzle characteristics optimized for use with Sterling Beads abrasives (right). This new rotating jetting-head-based tool, combined with the Sterling Beads abrasives, forms the basis of a new system of coiled tubing-conveyed intervention services designed to remove scale in downhole tubulars. The Blaster Services system features three scale-removal techniques that can be applied to a wide range of scale problems:

- The Scale Blasting technique combines the use of Sterling Beads abrasive with the new jetting tool for hard-scale removal.
- The Bridge Blasting technique uses a powered milling head and abrasive jetting, when scale completely plugs the tubular.
- The Jet Blasting technique uses the new jetting tool with nonabrasive fluids for soft-scale-removal applications.

The scale-removal system also includes a scale-removal design program, called Jet Advisor software, that enables an operator to optimize the jetting-tool configuration and nozzle size based on well conditions to maximize jetting power and head penetration rate. It also helps with the selection of either abrasive or nonabrasive—fluid only—scale-removal techniques. The Jet Advisor program alerts the operator to the risk of tubular damage due to headstalls—using steel damage and coiled tubing stick-slip analysis.



< Jet Blaster tool. Photograph (top) shows the toolbox containing the abrasive jetting system as delivered to the wellsite. The Jet Blaster down-hole tool (middle left) includes coiled tubing connections, check valves and disconnect equipment; dual-acting circulation unit; and a filter that prevents unexpected debris in the jetting fluid from clogging the jetting nozzles. The tool converts fluid power to a continuous speed rotation with a viscous shearing-fluid speed-controlled swivel for removing scale along the inside of tubular walls (insert middle right). Reaction forces from the two offset jet nozzles provide about 5 ft-lbf torque to rotate the swivel head at speeds less than 200 rpm. The jetting head consists of a nozzle carrier and a drift ring. In the Jet Blasting and Scale Blasting techniques, the nozzle carrier is assembled with two opposing tangential jets (bottom left). The offset jetting nozzles maximize hydrodynamic energy transport to the wellbore. The drift ring allows weight to be set down on the tool so that the tool will advance only after the entire minimum bore diameter is cleaned. In the Bridge Blasting technique, a positive displacement “Moineau” style motor (bottom center and right) can be used to drill scale bridges across tubing for Bridge Blasting applications. This motor can deliver 150 ft-lbf torque to the head module at 300 rpm.

Removing hard scale—For hard scales like iron, strontium and barium sulfate, nonabrasive fluid jetting and chemical treatments are inadequate. The controlled-erosive action of the Sterling Beads abrasive has been successful in removing every type of scale in tubing, including the most difficult barium sulfate scales, at rates up to 100 ft/hr [30 m/hr] or more. The Scale Blasting technique is a particularly good option when the scale encountered in the well is insoluble, unknown or of variable hardness. The system also provides a safe method to remove scale from downhole completion equipment. Rate of penetration (ROP) is controlled using a drift ring that ensures full tubing-diameter cleaning with minimum damage to the steel surface.

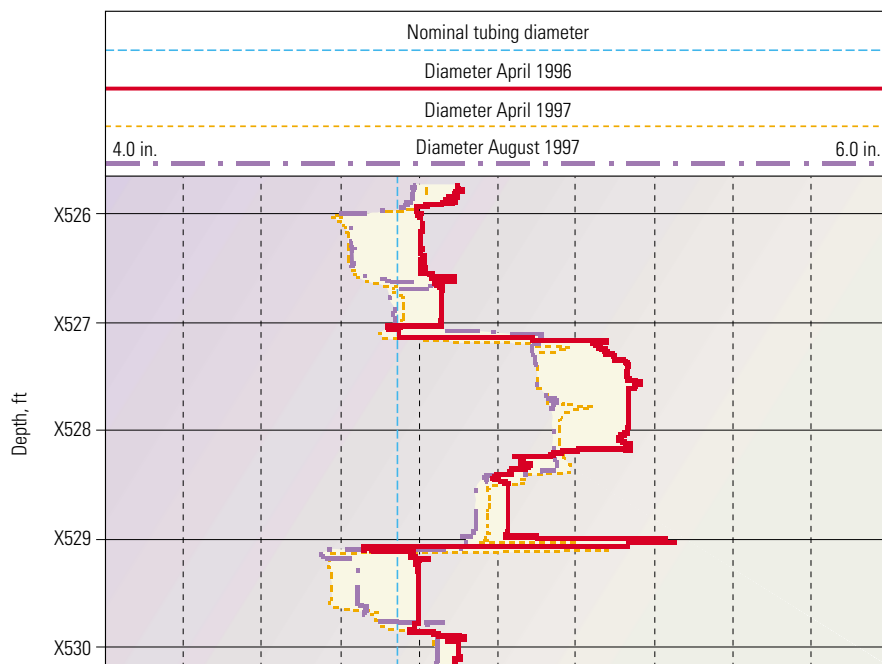
The Scale Blasting technique was used in the North Sea to remove hard barium sulfate deposits on two gas-lift valves, identified by multifinger caliper logs, in a multiple-mandrel gas-lift completion well (right).⁹ Well flowing pressure decreased as water was injected, and there was a possibility that the available gas pressure would be inadequate to reach the only remaining active valve in a side-pocket mandrel. Failure to remove and change a second damaged valve would have resulted in the well dying as water cut increased and led to a costly workover. Solvents were ineffective in removing enough scale to allow kickover tools to engage and latch onto the valves.¹⁰

The new coiled tubing-conveyed abrasive-jetting technology was used in this well for the first time in the North Sea. Jet Advisor software provided the optimal drift ring size, nozzle and nozzle-head size to efficiently clean the hard scale. The software also provided the optimal abrasive concentration and predicted scale-removal rates.

First, the damaged side-pocket mandrel was cleaned at a rate of 100 ft/hr [0.5 m/min]. Then, the other operating side-pocket mandrel was cleaned with the same procedures. The entire operation was evaluated by running the kickover tool and checking the possibility of changing the gas-lift valves in the cleaned side-pocket mandrels. A gamma ray log was also run to evaluate the remaining scale deposit in the completion (right). The damaged valve was successfully

9. Tailby RJ, Amor CB and McDonough A: "Scale Removal from the Recesses of Side-Pocket Mandrels," paper SPE 54477, presented at the 1999 SPE/IcoTA Coiled Tubing Roundtable, Houston, Texas, USA, May 25-26, 1999.

10. For a discussion of the use of kickover tools to remove retrievable gas-lift valves located in side-pocket mandrels: Fleshman R, Harryson and Lekic O: "Artificial Lift for High-Volume Production," *Oilfield Review* 11, no. 1 (Spring 1999): 49-63.

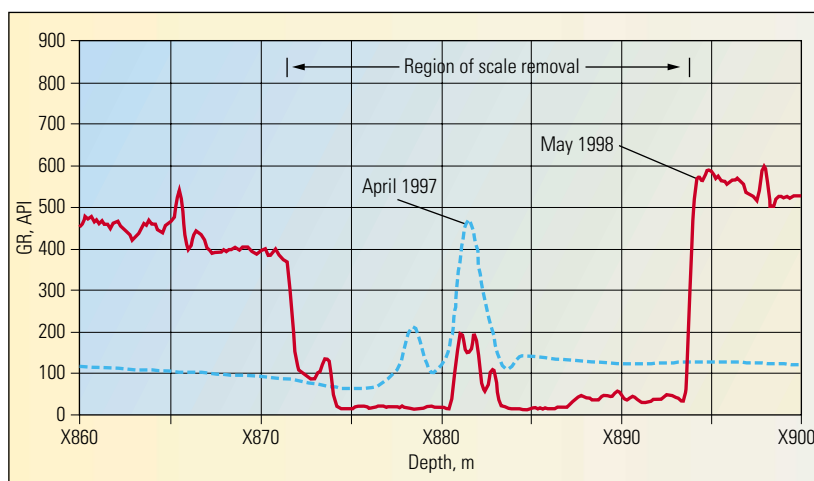


▲ Scale buildup between April 1996 and August 1997. Multi-arm caliper logs show scale accumulation (shaded) in the upper side-pocket mandrel.

retrieved and replaced. Abrasive jetting efficiently cleaned the scale without damaging the mandrel.

In another example, up to 0.38-in. [1-cm] thick barium sulfate deposits prevented an operator in Gabon, West Africa, from accessing and changing five gas-lift mandrels in a well with a tapered production-tubing completion. The well had not produced since 1994. Gauge cutter runs showed scale buildup bridged the tubing, blocking access to the lower section of the well. The workover objectives were to clean the tubing scale, change out gas-lift mandrels, and gain access to the well below the tubing.

Early attempts at conventional scale-removal methods, including several positive displacement motors (PDM) and milling runs, an impact hammer and another jetting system following dissolver treatments, were unsuccessful. The ability to remove hard barium sulfate scale under a wide range of conditions made the Scale Blasting technique an attractive alternative. Because of the tapered completion, several sizes of gauge rings and nozzle heads were required. The jetting fluid was formulated with standard concentrations of polymer and Sterling Beads abrasives to achieve optimum well cleanup and rate of penetration.



▲ Confirming scale cleaning. Gamma ray logs can be used to indicate the amount of scale removed over the 22-m [84-ft] cleaned interval centered at the side-pocket mandrel location. The 1997 gamma ray log shows the relative scale buildup on the lower side-pocket mandrel one year before treatment. The 1998 log was measured after scale was removed from the zone between X872 m to X894 m.

Jet Advisor software optimized the rotating jetting-head torque and abrasive cutting efficiency with rate, pressure and viscosity as variables in the 56°-deviated wellbore. The most effective pump rates and surface pressures were determined by the CoilCADE software, while the CoilLIMIT program was used to determine the safe working limits of the coiled tubing.

The treatment resulted in 6500 ft [1981 m] of tubing cleaned in a total jetting time of 25.5 hours. Average penetration rates were 600 to 900 ft/hr [3 to 5 m/min] in 3½-in. tubing, and 40 to 100 ft/hr [0.2 to 0.5 m/min] across the gas-lift mandrels and in the 2½-in. tubing. Successful treatments allowed the operator to replace the gas-lift mandrels, and the well now produces 2000 B/D [320 m³/d]. The removed gas-lift mandrels had been cleaned in all areas exposed to the wellbore and the valves were not damaged.

Removing scale bridges from tubulars—Scale deposits that completely bridge tubulars can be removed with a special adaptation of the Jet Blaster abrasive jetting tool using the Bridge Blasting technique. The Bridge Blasting technique incorporates a 1.69-in. diameter PDM specially modified to prevent Sterling Beads abrasive from clogging the motor's high-pressure labyrinth shaft seal. The PDM drives a combination jetting and milling head that uses a Reed-Hycalog diamond mill to make a small pilot hole in the deposit (above right). Radial jets complete the cleaning. Since the mill removes only a fraction of the total bridged deposit volume, the cleaning rate and overall mill and motor reliability are much higher than with conventional PDM-milling-cleaning methods.

A drift ring centers the tool and prevents mill damage to the tubulars—frequently a problem with conventional milling techniques. In hard, bridged deposits, a different jet-drilling head is used if the pilot mill does not achieve acceptable cleaning rates. The jet-drilling head uses four critically oriented jetting nozzles to drill through the scale bridge using a Sterling Beads slurry. A subsequent run with the Jet Blaster swivel with Sterling Beads abrasive is usually required to complete cleaning to the full diameter of the tubulars.



▲ Bridge Blaster milling head. The Bridge Blaster system can be configured with a radial jetting head, drift ring and a Reed-Hycalog mill (left), or with downward-facing abrasive jetting nozzles (right) that drill a hole through scale bridges that cannot be cut with tungsten carbide mills.

Iron sulfide [FeS₂] scale is a special problem for BP Amoco throughout the Kaybob south field in the Beaverhill Lake formation in Canada. The iron sulfate crystallites form directly on steel tubing, attaching firmly, and promote either bimetallic or crevice corrosion beneath the crystallites. These sour gas [H₂S] condensate wells deposit high molecular-weight compounds, such as asphaltene, on the iron sulfide crystallites inside tubing.¹¹

This unusual scale cannot be removed by hydrochloric acid, surfactants or chelating agents because asphaltene protects the scale from scale dissolvers. The scale can be removed only by mechanical techniques or by first chemically removing the asphaltene layers. Past experience with conventional methods for scale removal—including foamed acid, acid jetting combined with organic solvents such as xylene, and drilling, milling and tubing shakers—were inconsistent.

New abrasive jetting techniques using the Sterling Beads abrasive were evaluated in eight wells. Gelled water containing a xanthan bipolymer additive was used for friction reduction and improved cuttings transport. The Sterling Beads

weight concentration used in these wells was 2.5%. Treatment times varied from 1 to 4 hours for six wells treated with the Scale Blasting technique, and up to 13 hours in one of the two wells containing scale bridges treated with the Bridge Blasting technique (below). Rates of penetration vary depending on tool drift, nature of the deposits, occurrence of bridges when using the Scale Blasting technique, and wellbore restrictions. Overall, 10,400 ft [3170 m] of scale were successfully removed from the eight wells in 32.5 hours cumulative jetting time.

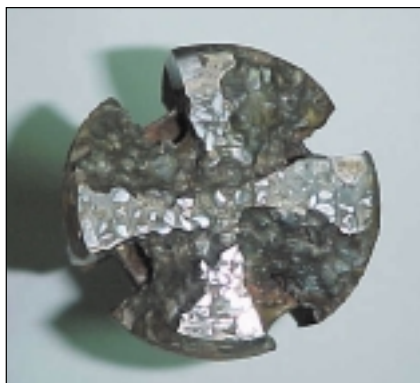
Removing sand plugs—When wellbore deposits are soft, acid soluble or chemically reactive, the nonabrasive Jet Blasting technique is the most cost-effective and efficient. The increased fluid-jet efficiency from the optimized jetting head maximizes cleaning ability on soft scale, fresh cement and filter cake. Other drilling damage and insoluble deposits benefit greatly from a combined chemical and jet-cleaning treatment.

An operator in south Texas was having difficulty removing sand plugs in a well with three fracture-stimulated zones that were isolated by sand plugs. Each sand plug was topped with a cap

11. Crombie A, Halford F, Hashem M, McNeil R, Thomas EC, Melbourne G and Mullins O: "Innovations in Wireline Fluid Sampling," *Oilfield Review* 10, no. 3 (Autumn 1998): 26-41.
12. Wigg H and Fletcher M: "Establishing the True Cost of Downhole Scale Control," paper presented at the International Conference on Solving Oilfield Scaling, Aberdeen, Scotland, November 20-21, 1995.
13. Rosenstein L: "Process of Treating Water," U.S. Patent No. 2,038,316 (April 21, 1936). This 1936 US patent is one of the earliest references to threshold inhibitors.
14. Nancollas GH, Kazmierczak TF and Schuttringer E: "A Controlled Composition Study of Calcium Carbonate Growth: The Influence of Scale Inhibitors," *Corrosion-NACE* 37, no. 2 (1981): 76-81.

	Blaster Services	Treatment time, hr	Length of scale removed, m	Tool drift O.D., mm
Well 1	Scale Blasting technique	1.5	1023	54
Well 2	Scale Blasting technique	1	45	46.7
Well 3	Bridge Blasting technique	13	162	46.7
Well 4	Scale Blasting technique	4	1108	46.7
Well 5	Scale Blasting technique	2.5	28	54
Well 6	Bridge Blasting technique	7	270	54/45
Well 7	Scale Blasting technique	2	511	54
Well 8	Scale Blasting technique	1.5	20	46.7

▲ Beaverhill Lake scale-removal results.



▲ Mill worn by silica flour.



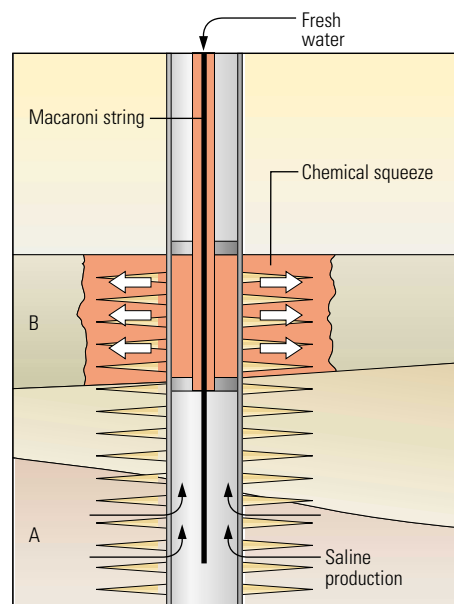
of silica flour to provide a better pressure seal. A drill motor with a mill was used to try to clean out the sand plugs. The first plug was cleaned out successfully, but the mill was completely worn down after cleaning 2 ft [0.6 m] of the second plug. A second mill managed to drill out only an additional 5 ft [1.5 m] in the plug before it was completely worn (above). The plug with silica flour on top had been crushed and packed tightly due to fracturing pressure from above, forming a hard fill.

Jet Advisor software was used to select the proper nozzle size for the Jet Blasting technique based on well conditions. Head components and sizes were based on well completion and fill material. The jetting fluid was a 2% potassium chloride [KCl] water with friction reducer, foaming agent and nitrogen [N₂]. Treatment resulted in a cleanout rate of 420 to 600 ft/hr [2 to 3 m/min]. The plugs and silica flour were removed from the well in less than one day, saving the operator the cost of the workover rig and five days in lost production.

Preventing Scale

The direct cost of removing scale from one well can be as high as \$2.5M, and the cost of deferred production even higher.¹² Just as prevention is better than cure in medical practice, keeping producing wells healthy is ultimately the most efficient way to produce hydrocarbons. In most cases, scale prevention through chemical inhibition is the preferred method of maintaining well productivity. Inhibition techniques can range from basic dilution methods, to the most advanced and cost-effective methods of threshold scale inhibitors.

Dilution is commonly employed for controlling halite precipitation in high-salinity wells. Dilution reduces saturation in the wellbore by continuously delivering fresh water to the sandface, and is the simplest technique to prevent scale formation in production tubing. It requires installation of what is called a macaroni string through the production tubing

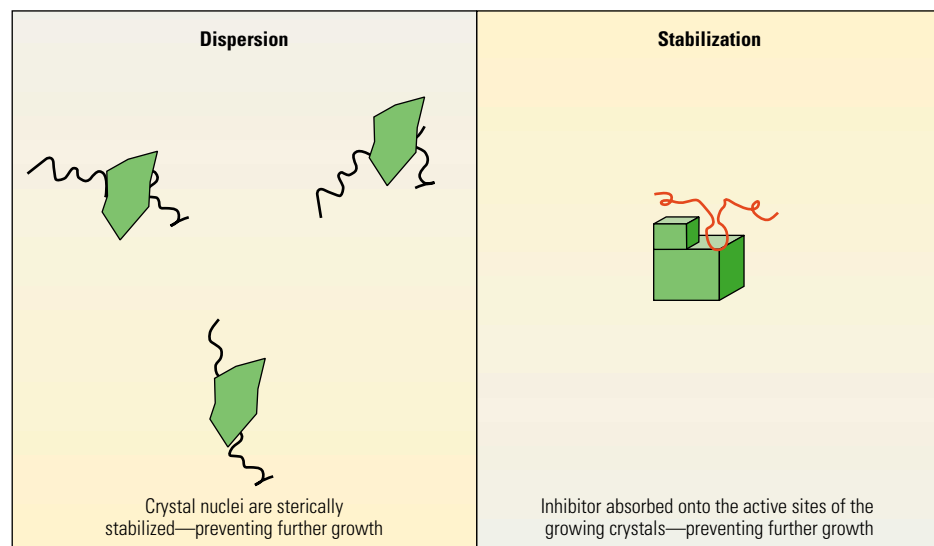


▲ Macaroni string. The small-diameter macaroni string, also called a spaghetti string, or capillary string, delivers fluids and chemicals into production wells. It delivers chemicals close to the interval, as shown at A, that is producing the fluid needing treatment. A periodic inhibitor squeeze into the formation is shown at B.

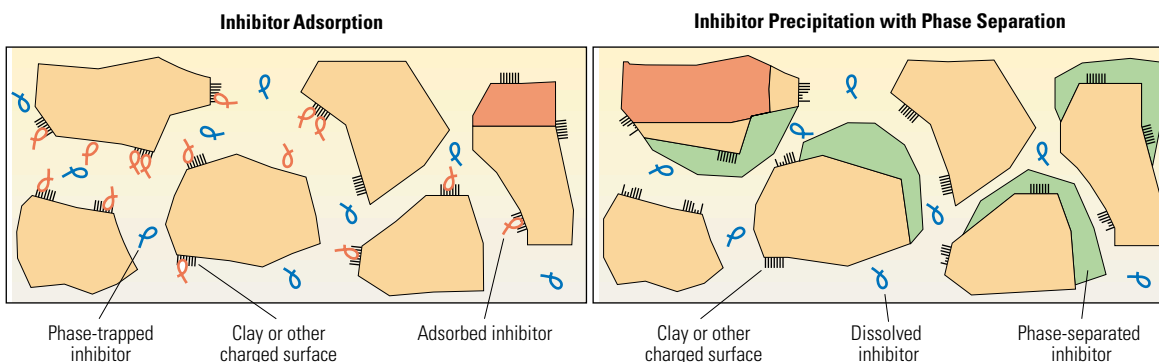
(above). The macaroni string is typically small-diameter tubing—less than 1½-in.

In addition to dilution, there are literally thousands of scale inhibitors for diverse applications ranging from heating boilers to oil wells. Most of these chemicals block the growth of the scale particles by “poisoning” the growth of scale nuclei. A few chemicals chelate or tie up the reactants in a soluble form. Both approaches can be effective, but each requires careful application as treatments show little tolerance for change in the producing system. Chelating inhibitors block precipitation or scale growth only for a certain limited level of oversaturation. Equilibrium upsets occur, even in protected systems, allowing scale to precipitate. Because chelating agents consume scale ions in stoichiometric ratios, the efficiency and cost-effectiveness of chelants as scale inhibitors are poor.

In contrast, threshold scale inhibitors interact chemically with crystal nucleation sites and substantially reduce crystal growth rates. Threshold scale inhibitors effectively inhibit formation of mineral scales at concentrations on the order of 1000 times less than a balanced stoichiometric ratio.¹³ This considerably reduces the treatment cost. Most scale inhibitors are phosphate compounds: inorganic polyphosphates, organic phosphate esters, organic phosphonates, organic aminophosphates and organic polymers. These chemicals minimize scale deposition through a combination of crystal dispersion and scale stabilization (left).¹⁴



▲ Dispersion and stabilization. Dispersion (left) prevents small seed crystals of scale from adhering to tubing walls and other crystal particles. Stabilization chemicals modify the deposited scale structure, preventing additional crystal attachment.



▲ Adsorption and precipitation. Scale inhibitors yield the best treatment lifetimes when they are retained in the formation either by adsorption to the pore walls (*left*), or by precipitating in the pore space (*right*).

Inhibitor lifetime—Scale inhibitors are retained in the formation by either adsorbing to the pore walls or precipitating in the pore space. Adsorption is most effective in sandstone formations (*above*). Treatment lifetimes depend primarily on the surface chemistry, the temperature, and the pH of the liquid contacting the formation, and are occasionally unusually short (3 to 6 months) because the adsorption capacity of reservoir rocks under reservoir conditions is limited.¹⁵ Under special conditions, such as high adsorption-capacity formations and low water-production rates, up to two-year lifetimes can occur.

Normally, treatment lifetimes exceed one year for properly designed treatments in which precipitation is the inhibitor retention mechanism—even when high water-production rates are encountered.¹⁶ For example, phosphates and phosphino-carboxylic acid inhibitors are among those known to prevent calcium carbonate scale. Calcium ions are often liberated when the inhibitors are placed in carbonate formations, and precipitation is the dominant long-term retention mechanism in carbonate formations. A calcium chloride brine overflush is often pumped to induce scale inhibitor precipitation and extend the treatment lifetime in reservoirs that do not naturally contain enough soluble calcium to precipitate the inhibitor.¹⁷

Long inhibitor lifetime can be also be achieved by pumping large volumes of inhibitor deep into the formation, such that the inhibitor is exposed to and absorbed to a large surface area. This is not always successful because squeezing water-based inhibitors into oil zones can lead to a temporary change in formation wettability. This results in unacceptably long production-recovery times. Alternative oil-soluble inhibitors that do not cause the formation rock to become water wet are needed. New fluids based on critical point wetting of rock are being tested for inhibitor

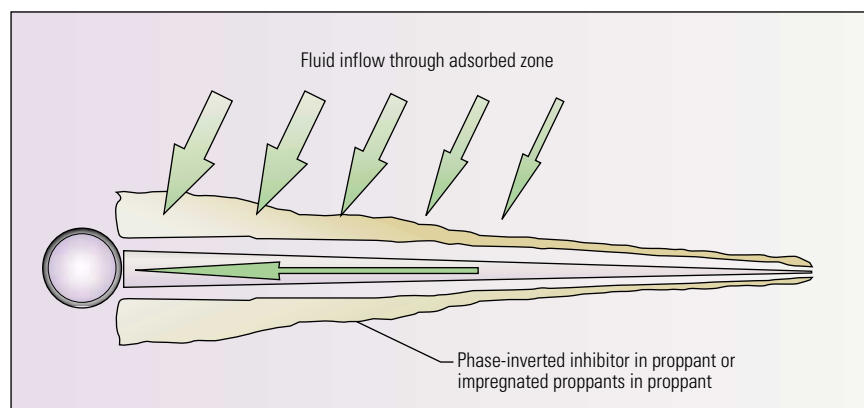
enhancement. These make the reservoir rock “super wet,” allowing a higher degree of inhibitor retention and a longer protection lifetime.

Commercial software, such as the Squeeze-V program that was developed at Heriot-Watt University, Edinburgh, Scotland, models the retention and release of scale inhibitors by adsorption or precipitation. This program is used to optimize inhibitor concentrations, treatment and overflush volumes to maximize inhibitor lifetime. It can also be used to match histories of previous treatments as part of an overall strategy of continual improvement in scale management.

Improving inhibitor placement—Ultimately, treatment performance is based on scale prevention, not on the duration of the inhibitor. Proper inhibitor placement is a key factor in the performance of an inhibitor squeeze treatment. Bullheading the inhibitor into a formation can lead to overtreatment of low-pressure and high-permeability zones, and undertreatment of

high-pressure and low-permeability zones. Thus, it is considered good practice to place scale inhibitors in heterogeneous formations using the same placement techniques employed to control acid placement. In fact, there are significant advantages to combining the acid and scale-inhibitor treatments to ensure that the scale inhibitor is controlled along with the acid. Care must be taken to insure that the acid pH does not exceed that required for inhibitor precipitation.¹⁸

Integrating scale inhibitor with fracture stimulation—Protection of propped fractures against mineral scale fouling is critically dependent upon proper inhibitor placement. Portions of the fracture that are left untreated by the inhibitor might be irreversibly damaged because of the ineffectiveness of contacting mineral scales in proppant packs with scale solvents. As a result, there have been efforts to pump scale inhibitors in fracturing fluid, thereby guaranteeing proppant-pack coverage.¹⁹

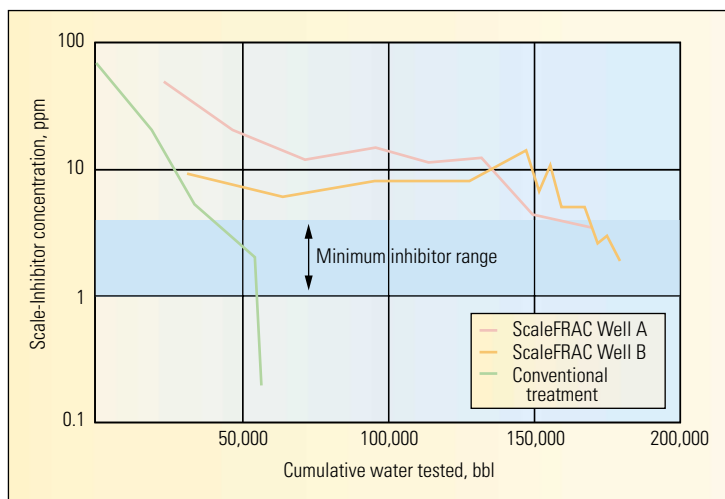


▲ Fracture stimulation with inhibitor placement. High-efficiency scale-inhibitor placement is achieved by pumping the inhibitor into the fracturing fluid during fracture stimulation. The inhibitor is retained by adsorption on the formation in the leakoff zone, or by precipitation on the proppant. As formation water passes through the inhibitor-absorbed zone, it dissolves enough inhibitor to prevent the water from precipitating in the fractures and wellbore.

An alternative inhibitor delivery system, implemented by Schlumberger, called the ScaleFRAC system combines a scale-inhibitor treatment and fracture treatment into a single-step process by using a new liquid inhibitor compatible with fracturing fluids. The scale inhibitor is effectively placed everywhere in the propped fracture by pumping the scale inhibitor during the pad and sand-laden stages of the fracturing treatment (previous page, bottom). The new process eliminates a scale squeeze treatment immediately following a fracture stimulation treatment, and also circumvents the problem of slow oil-production recovery caused by wettability changes produced by conventional scale-squeeze treatments.

The new inhibitor delivery system has been used extensively on the North Slope in Alaska, and has found applications in the North Sea and the Permian Basin. For example, results in the Permian Basin show that inhibitor concentrations in produced water remain above threshold values necessary to prevent scale deposition significantly longer than conventional treatments (above right). The new integrated inhibitor-fracture treatment provides sustained fracture productivity due to better inhibitor placement. It also simplifies wellsite logistics, due to combining the squeeze and inhibitor treatments; and the well returns to production faster because there is no shut-in to allow the inhibitor to adsorb or precipitate in the formation.

Recently, AEA Technology in England developed a new porous ceramic proppant that is impregnated by the scale inhibitor for use during hydraulic fracturing.²⁰ The novel feature of the AEA scale inhibitor is that the salt of a



▲ Inhibitor retention. Inhibitor elution data measured in two wells treated with the ScaleFRAC system show that inhibitor concentrations in the produced water remained above the threshold value—typically 1 to 5 ppm—to prevent scale deposition and growth. Wells A and B treated with the new inhibitor-placement technique produced scale-free water significantly longer than those with conventional treatments.

commonly used oilfield scale inhibitor is precipitated such that it fills the porosity of a lightweight ceramic proppant. The filled ceramic proppant can then be substituted for a fraction of the original proppant in the fracture-treatment design. Upon production, any water flowing over the surface of the impregnated proppant will cause dissolution of the scale inhibitor—protecting the well against scale depositing from the water. The inhibitor-release mechanism is dissolution of the inhibitor from the interstitial pores of individual proppant grains. This avoids wasted inhibitor by phase trapping. After all the inhibitor is dissolved, the ceramic substrate remains and continues to serve as a propping agent.

Conclusion

There have been many significant advances in scale control and remediation in recent years. Today, operators have access to a portfolio of chemical and mechanical products designed to remove scale and prevent its buildup. The improvements in placement technology, reservoir chemistry and intelligent fluids furnish more cost-effective options for chemical scale inhibition and removal in the formation. Developments in scale-removal services incorporating new abrasive materials are providing fast, reliable ways to remove scale inside tubulars without risk to the steel tubing.

Each new technology improves one aspect of scale control in a wellbore. Combined, these new technologies become part of a scale-management process in which one can apply surveillance methods to identify the onset of scaling conditions and develop the optimum strategy for reducing scaling-related production losses and remedial expenses. The strategy may include elements of scale prevention and periodic removal. Engineers working in scale-prone reservoirs are grateful for every improvement in the technology used to combat their scale problems. —RCH

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