Coiled Tubing: The Next Generation

Building on a technological resurgence during the 1990s, this unique well-intervention technique firmly established a place in mainstream operations. We review advances in surface equipment and downhole tools that increase operational efficiency and safety, improve wellbore and reservoir remediation methods, and also facilitate drilling and completing wells with coiled tubing.

Once considered high-risk and applicable only for niche services, coiled tubing (CT) is now an essential tool for many well-intervention operations. In the late 1980s and throughout the 1990s, this technology gained wider acceptance among operators because of its ability to reduce overall costs, greatly improved reliability and an expanding range of applications, which resulted in significantly increased CT activity (next page).

Used generically, coiled tubing describes continuous lengths of small-diameter steel pipe, related surface equipment and associated workover, drilling and well-completion techniques. Since its introduction to oilfield operations in the early 1960s, CT utilization has increased because of better manufacturing, larger tube diameters and advances in equipment that improved operational efficiency (see “A History of Coiled Tubing,” page 42).

Coiled tubing is spooled onto a reel for storage and transport. These strings can be 31,000 ft [9,450 m] long or more, depending on reel size and tube diameters, which range from 1 to 4½ in. A hydraulic power pack, or prime mover, controlled from a console in a central control cabin drives the injector head to deploy and retrieve coiled tubing. The large storage reel also applies back-tension on the tubing.

The continuous tubing passes over a goose-neck and through an injector head before insertion into a wellbore through well-control equipment that typically consists of a stuffing box, or packoff, riser and blowout preventer (BOP) stack on top of the wellhead. This process is reversed to retrieve and spool coiled tubing back onto the reel. Modern CT equipment and techniques have several advantages over conventional drilling, workover and snubbing units.

These include quick mobilization and lower cost, expedited operations with no need to stop and connect tubing joints, and reasonably high load capacities for deeper vertical and high-angle reach compared with wireline and slickline. The flexibility of working under pressure in “live” wells without killing a well and the unique capability to pump fluids at any time regardless of position in a well or direction of travel are also advantages.
These capabilities are especially useful in wellbore cleanouts, jetting with inert gases or light fluids, perforation acid washes, acid or fracture stimulations and sand-consolidation treatments, cementing, fishing and milling, underreaming and underbalanced drilling. Adding an electric line, data or power cables inside coiled tubing strings facilitates well logging, downhole monitoring or control, directional drilling and electrical submersible pump (ESP) installations.

Deeper high-angle wellbores are increasingly common and many are beginning to require remedial interventions. Going into deeper wells increases coiled tubing weight, requiring stronger pipe and injector heads plus improved fluids.2 CT is a viable option for these demanding remedial operations, but detailed planning is required to ensure job safety and efficiency.

Better tubular manufacturing and quality control had a significant positive impact, but equipment optimization and improved operational techniques and procedures have been equally important in improving CT performance and reliability. This article reviews the latest developments in CT wellsite efficiency, wellbore and reservoir remediation applications, new downhole tools, reentry and underbalanced drilling operations and artificial lift.

Wellsite Efficiency

A feasibility study in 2001 and subsequent engineering efforts resulted in a new offshore CT unit, which was launched in 2003. The automated, modular CT SEAS Coiled Tubing Safe, Efficient Automated Solutions system was first installed on a BP Valhall field platform in the North Sea Norwegian sector (above).

A typical Valhall field horizontal well requires 5 to 12 separate fracture stimulations. To save time, BP performs drilling and completion operations simultaneously on the platform. After well-completion equipment is installed, the drilling rig skids to the next wellhead slot. A large CT unit and a stimulation vessel complete the wells.

The first CT run performs wellbore cleanout and perforating. The stimulation vessel then pumps a proppant fracturing treatment. The next CT run cleans out excess proppant, but leaves a sand plug to isolate the preceding fracture. The next interval is perforated, and this cycle continues until all zones are stimulated.

In the past, conventional CT units operated with a 13-member crew. The equipment spread consisted of a control unit, reel and power pack, well-control equipment, two high-pressure positive displacement pumps, mud shakers, flow valves and chokes, and an injector-head stand.

Recent extended-reach wells with 2,000-m [6,562-ft] horizontal sections drilled to tap outer areas of the field are more challenging than previous wells. The ability to use larger, heavier 2 7/8-in. coiled tubing would increase operational efficiency and allow completion of additional intervals, but required a redesigned CT unit.

An evaluation of platform operations and requirements, and local regulations helped engineers develop the new CT SEAS unit. The new design targeted decreases in rig-up time and overall operational cycle times to achieve a 15% efficiency increase and a 30% reduction in CT personnel. The resulting CT SEAS unit consists of modular components that are easy to deliver and assemble, produce zero discharge and optimize space utilization offshore (next page, top).

Flexibility in equipment layout reduces rig-up time and improves CT operations. Conventional offshore CT units typically involve 54 crane lifts during rig-up; the new unit cuts this number to 36. CT SEAS components travel to the wellsite preassembled and pretested on skids to reduce the number of crane lifts and the amount of manual equipment handling.

The injector head is transported with the connector installed. A self-folding gooseneck and partially automated process for stabbing coiled tubing into the injector head limits personnel exposure to hazards.

To simplify hookups and pressure testing, the improved skid designs have fewer valves and some piping is connected and tested in advance as modular components. Distributed electric control of valves in place of centralized hydraulic control reduces the number of hydraulic connections. The CT SEAS system has 36 hydraulic connections instead of the usual 84 of older units.

Control cabin ergonomics allow operators to react quickly and efficiently to any situation (next page, bottom). Automated process and equipment control reduces crew requirements from 13 to 9 members and allows the unit operator to focus on well-intervention efficiency.

Process-control software incorporates automated safety features that reduce risk exposure in settings prone to human errors.

During CT operations, job parameters are monitored, recorded and plotted by the CoilCAT coiled tubing computer-aided treatment system for real-time data acquisition. The InterACT real-time monitoring and data delivery system provides secure Web-based, two-way communication that makes field data available at all stages of a CT operation.3

Authorized client and Schlumberger personnel have access to data and can monitor jobs remotely. Streaming data transfer facilitates real-time evaluation of operations to help fine-tune job procedures and speed up decision-making.

The CT SEAS unit has improved wellbore cleanout efficiency and allowed completion of more difficult flank wells. The capability of running up to 6,000 m [1,829 ft] of 2 7/8-in. coiled

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A safer, more efficient offshore unit. The CT SEAS unit consists of modular skids containing multiple systems for optimal utilization of platform space, efficient rig-up and easy delivery. This design reduces the number of crane lifts required to rig up on a platform or move from well to well. The principal components are an injector head and jacking frame, blowout preventer (BOP) skid, stackable control cabin and tool shop, shaker and tank system, BOP-control and choke skid, hydraulic power unit and drop-in-drum tubing reel. A self-folding gooseneck and partially automated process for stabbing coiled tubing into the injector head reduce the risk of accidents and injuries. Unit automation further improves safety and efficiency, and reduces unit crews from 13 to 9 members.

CT unit and system control. A cyber-based system in the CT SEAS cabin operates the reel, injector head, well-control equipment, flow-control chokes, mud shakers and pumps.
A History of Coiled Tubing

Early coiled tubing (CT) technology can be traced to project PLUTO (Pipe Lines Under The Ocean)—a top-secret effort to install pipelines across the English Channel during World War II.¹ In June 1944, Allied engineers deployed several pipelines to provide fuel for D-day invasion forces. Most of the lines were fabricated from 40-ft [12-m] joints of 3-in. inside diameter (ID), 0.212-in. wall thickness steel pipe welded together to form 4,000-ft [1,220-m] sections.

These larger pipe sections were welded end-to-end, spooled onto 40-ft diameter floating drums and towed behind cable-laying vessels. Successful deployment of 23 pipelines ranging in length from 30 to 70 miles [48 to 113 km] set the stage for future development and use of coiled tubing in oil and gas wells.

Elements of modern CT injector heads can be found in a device developed by Bowen Tools during the early 1960s for deploying radio antennae to the ocean surface from submarines submerged as deep as 600 ft [183 m]. The antennae were stored on a spool beneath the vessel's hull. One section was milled for a permanent well completion. These basic concepts aided in the design of CT units and injector systems.

The first such unit, built by Bowen Tools and the California Oil Company in 1962, included an injector rated for surface loads up to 30,000 lb [13,608 kg] that ran a continuous string of 1,315-in. outside diameter (OD) pipe. The unit’s 9-ft [2.7-m] diameter storage reel included a hub with a rotating fluid swivel to allow continuous pumping down the coiled tubing.

However, low yield-strength steels and the numerous end-to-end, or butt, welds required to fabricate continuous tubing could not withstand repeated bending cycles and high tensile loads. Weld failures, equipment breakdowns and fishing operations to retrieve lost coiled tubing caused operators to lose confidence in this technique.

From the 1960s through the 1970s, manufacturing companies, including Bowen Tools, Brown Oil Tools, Uni-Flex, Inc., Hydra Rig Inc. and Otis Engineering, continued making improvements in CT equipment and injector heads. These changes allowed larger coiled tubing sizes to be used at greater working depths, improved coiled tubing performance and reliability, and reduced the number of surface equipment failures. Unfortunately, an overall poor success rate and a reputation for limited reliability continued to plague CT operations.

The late 1970s and early 1980s represented a turning point for coiled tubing, which up to that time was milled, or formed, in 1,500-ft [457-m] sections. In 1978, improved manufacturing quality and continuous milling allowed fabrication of 1¼-in. OD pipe. In 1980, Southwestern Pipe introduced 70,000-psi (70-ksi) [483-MPa] high-strength, low-alloy (HSLA) steel for coiled tubing. The early 1980s saw the introduction of 1½-in. and 1¼-in. OD coiled tubing.

In 1983, Quality Tubing Inc. began using 3,000-ft [914-m] sheets of Japanese steel to reduce the number of required welds by 50%. Later in the 1980s, Quality Tubing introduced bias welding to eliminate butt welds. This process involved cutting flat steel strips diagonally to enhance coiled tubing strength and life by spreading the heat-affected weld zone spirally around the tube. In addition, a better understanding of coiled tubing fatigue enabled improvements in reliability and pipe performance.

In 1990, the first string of 2-in. coiled tubing was milled for a permanent well completion. Soon after that suppliers began manufacturing 2½-, 2¾-, 3½- and 4¼-in. OD sizes for well-servicing applications. Today, coiled tubing is manufactured from steel with high yield strengths of 90, 100, 110 and 120 ksi [620, 689, 758 and 827 MPa], as well as corrosion-resistant alloys. Higher strength steel, larger diameters and the need to reduce costs were key factors behind the CT revolution of the 1990s, and subsequently accounted for the extraordinary increase in concentric, or through-tubing, well-intervention work.


In the new CT unit design, the current and future success of this technology can be attributed to platform designs tailored to CT requirements. To date, all of the targeted efficiency gains have not been realized on the Valhall platform, but with each campaign the team moves closer to those goals.

The need for efficient CT technology is not limited to offshore operations. Schlumberger developed the CT EXPRESS rapid-deployment coiled tubing service for intermediate-depth onshore wells (next page, top). This system comprises two trucks—a purpose-built CT unit and combination nitrogen and liquid pump—operated by three people. It provides the same capabilities as conventional units with five-person crews.

The combination pumper includes a liquid-nitrogen tank and liquid-additive systems, and provides electrical and hydraulic power. This unit is designed for applications involving relatively low pump rates, moderate pressures and continuous operations for long periods.

Tubing remains stabbed in the injector head during transportation, and the bottomhole assembly (BHA) can be assembled and pressure tested prior to arrival on location. A drop-in-drum tubing reel and innovative BOP pressure-test stand facilitate unit mobilization. For rig-up safety and efficiency, no hydraulic or electric connections have to be made on location.

The unit operator controls the reel, injector head and BOP stack from a cyber-based control cabin, which utilizes available personnel more effectively and improves wellsite communication. There are also separate stand-alone control panels for operation of individual equipment components.

Statistics from CT operations show that inaction or incorrect actions contribute to at least one-third of all failures. About 83% of the failures were triggered by a downhole event, resulting in forces that exceeded safe CT working limits. To address this problem, the Schlumberger IIC Intelligent Injector Control, which is compatible with both conventional and new CT SEAS units, provides automated control of CT conveyance.

In conjunction with CoilCADE coiled tubing design and evaluation software, IIC technology ensures that CT operations remain within specified job parameters. This system performs automated injector load, or pull, tests and controls speed, applied load, depth and other parameters while running in or out of a well.
This is particularly important during critical logging, cementing and high-pressure applications, or weight-sensitive milling or drilling operations. Predetermined trip schedules and slow-down points protect completion equipment, such as profile nipples. Programmed safety limits provide overpull protection and emergency shutdown for downhole obstructions.

The automated IIC control system protects wellbore and completion equipment and helps prevent downhole failures caused by human error. In addition to improvements in CT units and surface equipment, a better understanding of stresses and fatigue and more effective pipe management have improved service quality and job safety.

**Tube Reliability**

Results from an eight-year Schlumberger analysis of tube flaws and failures indicated that coiled tubing utilization efficiency is improving. A better understanding of tube failures and a focused pipe-management program contributed to increased CT reliability and improved service quality. As part of an ongoing Coiled Tubing Failure Analysis Program, Schlumberger investigated and classified failure causes and mechanisms (left).

These data provide valuable input for research, development and engineering efforts, training and competency programs, and quality-assurance plans. Based on identified trends and failure causes, Schlumberger implemented preventive field procedures to mitigate coiled tubing failures.

The result was a steady increase in the number of Schlumberger jobs per 1,000 ft [305 m] of coiled tubing purchased from 2 in 1998 to 3.6 in 2003. The number of successful jobs between failures also improved from 100 in 1999 to a high of 235 in 2001.

Schlumberger developed the CT Pipe Management Program to track and address tube flaws and failures. Failures while coiled tubing is in a well or being bent at the surface can have a catastrophic impact on safety, the environment and intervention economics. Significant improvements have been made to reduce the number of CT failures.

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Coiled tubing inspection. Improved pipe inspection helps reduce tube failures and optimize pipe life. The CT InSpec wellsite system uses 12 ultrasonic probes, arranged radially, to monitor wall thickness and pipe ovality over variable CT interval lengths (top). This new device measures tubing wall thickness as coiled tubing comes off the reel (bottom).

Tube materials, manufacturing processes and quality control before coiled tubing goes to the field have improved through an alliance with CT supplier Precision Tube Technology Inc. The CoilSAFE coiled tubing risk assessment system, maintenance of the pipe, and planning tools, such as CoilSAFE coiled tubing risk assessment system, help address operational safety. The Schlumberger global tubing inventory has aided in understanding coiled tubing performance by requiring that failures be recorded, analyzed and categorized.

The PipeSAVER coiled tubing storage inhibition system has improved coiled tubing handling by mitigating mechanical damage and corrosion. Training personnel in the proper use and maintenance of the pipe, and planning tools, such as CoilSAFE coiled tubing risk assessment system, help address operational safety. The Schlumberger global tubing inventory has aided in understanding coiled tubing performance by requiring that failures be recorded, analyzed and categorized.

Fracturing and acid stimulation through coiled tubing erode or corrode the steel. Certain well environments, such as chrome tubulars, cause external coiled tubing abrasion, and CT is being used at higher pressures, with the definition of “high-pressure” constantly increasing. These increased demands require a better means of monitoring CT integrity.

Several CT inspection systems have been developed. The universal tubing integrity monitor (UTIM) measures tube diameter and ovality. Other systems that detect cracks and pits, and give an average wall thickness have niche applications, but none are completely satisfactory. These limitations drive ongoing research and development in CT inspection.

Technology is currently being developed to address flaw identification and description, the effects of flaws on coiled tubing life, and assessment of related risks. The new ultrasonic CT InSpec real-time device, for example, monitors both ovality and wall thickness (above). Wall thickness is directly related to tubular burst strength, remaining string life, string abrasion and erosion effects and critical load-conveyance effects.

These measurements help users optimize string life and reduce tube failures in the field. The CT InSpec device does not address all CT inspection issues, but is a significant step forward. Combining this technology with existing magnetic-flux leakage or ultrasonic shear measurements may allow detection of localized flaws, such as pitting and corrosion. In addition to improved CT string management, new developments are optimizing wellbore cleanout operations.

Wellbore Remediation
About 50% of CT operations involve removing formation sand, fracturing proppants or other solids from wells (next page, top). These materials limit or prevent production, block the passage of wireline or other downhole tools, and interfere with completion and well-intervention operations. Conventional CT techniques often leave solids behind, requiring repeated cleanout attempts over an extended period, which increase costs and delay production.

To address this problem, Schlumberger conducted extensive testing directed at understanding solids transport by cleanout fluids. The resulting PowerCLEAN engineered fill removal service is an integrated approach that consists of specialized fluids, improved jetting nozzles, design software and a real-time system that monitors returning solids at the surface (next page, bottom).

Mixed with fresh water or seawater, PowerCLEAN fluids create a low-friction, high-viscosity stable solution that extends cleanout effectiveness to 325°F [163°C]. Water, guar, hydroxyethyl cellulose (HEC), xanthan and viscoelastic surfactants (VES) can also be used with the PowerCLEAN system up to their temperature limit—about 250°F [121°C].

Previous CT nozzle designs commonly have forward-only or forward and backward jets that do not effectively remove solids from high-angle wells. New PowerCLEAN nozzles have no moving parts, but create a swirling effect that provides continuous jetting; this utilizes fluid energy more efficiently and removes solids at greater than twice the rate of conventional nozzles.

The PowerCLEAN software integrates cleanout simulation with job optimization. Job parameters include circulating rate, CT running

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speed when penetrating fill, particle-bed depth, CT pulling speed for sweeping solids uphole, and number and length of sweep before running back in. The software accounts for factors such as maximum surface pressure and pump rate, acceptable bottomhole pressure (BHP), entrained solids concentration, fluid leakoff or inflow and solids transport.

Additional constraints ensure safe, problem-free cleanouts. The solids bed is not allowed to exceed a specified height that avoids drag on the coiled tubing, higher friction pressures and stuck pipe. In addition, the volume of solids that can be lifted above the nozzle is limited. This helps ensure that the coiled tubing can be pulled out in the event of lost circulation because of pump failure or excessive fluid leakoff. These safety constraints typically result in multiple sweeps to remove large fill volumes.

The real-time PowerCLEAN solids monitor uses acoustic sensors to detect returning solids at the surface and help determine whether a cleanout is progressing as planned. This non-intrusive monitor mounts on an elbow of the flowback line. The PowerCLEAN system recently played a key role in wellbore-cleanout operations in continental Europe and the Gulf of Mexico.

After hydraulically fracturing a gas well completed with a 7-in. liner, the operator needed to clean out the wellbore at balanced pressure conditions to avoid damaging the well. A 59-bbl [9.4-m³] volume of bauxite proppant filled the wellbore from about 13,700 to 16,400 ft [4,176 to 4,999 m], a length of 2,700 ft [823 m]. The maximum well inclination at this depth was 31° and the bottomhole temperature (BHT) was 304°F [151°C].

A 1 3⁄4-in. coiled tubing string pumping the new cleanout fluid penetrated fill at about 6 to 10 ft/min [1.8 to 3 m/min]. The PowerCLEAN software predicted that other fluids would not provide an effective cleanout because of the high BHT and large casing. It also determined that several sweeps would be required to remove solids that settled in high-angle wellbore sections.

Each CT penetration into the fill was limited to 80 ft [24 m], which minimized the solids dune height and prevented coiled tubing from becoming stuck if fluid loss occurred or pumping stopped. Sweep speed while pulling out of the well was 10 to 20 ft/min [3 to 6 m/min] to ensure complete fill removal.

An optimal flow rate through the 21,000 ft [6,401 m] of coiled tubing was achieved at pressures below 4,000 psi [27.6 MPa] because of the low-friction PowerCLEAN fluid. Solids returns were monitored at the surface in real time. The well was cleaned without problems and 59 bbl of bauxite proppant were recovered.

In another well, the PowerCLEAN service was used to remove excess bauxite from a Gulf of Mexico well in order to replace the gravel-pack screen assembly. This wellbore was completed with a 3 1⁄2-in. liner and had a complex trajectory with a maximum deviation of 70°. At a BHT of less than 200°F [93°C] and a 0.75-bbl/min [0.12 m³/min] pump rate, the PowerCLEAN nozzle with a xanthan-base fluid resulted in an optimized cleanout.
Creating only small pits (left failures (surfaces, which can cause ductile tubular steel during prolonged jetting in one spot. Scales, but does not cause excess damage to erosive performance of sand on hard, brittle soluble (fracture toughness, low friability, and are acid soluble (top)). This nontoxic material matches the erosive performance of sand on hard, brittle scales (middle left and right). Glass beads and limestone particles tend to bounce off steel surfaces, creating large, deep craters that eventually may result in erosion through tubular walls (bottom left). Sterling Beads particles shatter on impact, creating only small pits (bottom right).

Based on real-time monitoring, cleanout operations removed 16,500 lbm [7,484 kg] of bauxite in 12 hours. A subsequent CT run tagged the gravel-pack assembly rope socket, confirming that the well was clean. After gravel-pack screens were replaced, well production increased from 0.5 to 2.5 MMcf/D [14,320 to 70,600 m³/d].

Downhole deposits of inorganic scales in wellbore tubulars are a serious well-intervention problem (above left). Scale buildup changes the surface roughness of tubulars, increasing frictional pressure and restricting production. Additional scale growth decreases tubular flow area, prevents access to deeper sections of a well and ultimately may block the tubing completely. Extremely hard, insoluble scales, such as strontium or barium sulfate, may form when injected seawater breaks into a well.

In Brazil, Petrobras used abrasive-jet CT technology to clean heavy barium sulfate scale from production tubing in an offshore well. The well was located on a fixed offshore platform and no workover rigs were available, so tubing replacement was not an option. CT provided a means of conveying mechanical scale-removal tools and circulating cleanout fluids without a conventional rig.

Methods such as chemical dissolvers, slickline brushes and downhole motors had successfully removed scale in other area fields. In some of these cases, however, residual debris fell to the bottom of wells and blocked the perforations, requiring additional cleanout operations.

Schlumberger Blaster services use high-pressure jetting technology to remove downhole deposits (above). This specialized system uses solvents or special abrasive material to remove scale without damaging tubulars or completion equipment, such as profile nipples, subsurface safety valves or sliding sleeves. This technology comprises three techniques—Jet Blaster, Scale Blaster and Bridge Blaster scale-removal services.

Jet Blaster techniques use conventional fluids or scale-dissolving solvents with a radial jetting tool. The Scale Blaster approach uses the Sterling Beads safe hard scale-removal system developed at Schlumberger Cambridge Research and Development in England to remove hard, inert scales (left). By properly selecting particle hardness, shape, size, density and fracture toughness, researchers achieved unique properties that remove scale without damaging steel surfaces.

The Bridge Blaster technique combines a positive displacement motor (PDM) and a 1¼-in. tapered mill with the radial jetting tool and the Sterling Beads system modified to prevent PDM clogging. This system drills scale deposits or cement plugs through tubing without damaging wellbore equipment. The small tapered mill partially removes the scale deposit while jetting removes the rest. Removal rates are higher than with conventional milling.
Blaster design software helps select jetting tool geometry—drift ring, nozzle head, port size and configuration—required fluid rates, expected treating pressures, abrasive material concentrations and scale-removal rates. The software also estimates consumables, such as gelling agents, mixing products and abrasive materials.

The coiled tubing BHA encountered scale at 2,546 m [8,353 ft] in the Petrobras well. Using a xanthan-gelled brine and 3%-by-weight Sterling Beads abrasive particles, the Jet Blaster tool achieved a cleanout rate of 12 to 15 m/hr [38.4 to 49.2 ft/hr] from 2,546 to 3,087 m [10,128 ft]. Pumping at 0.23 to 0.27 m³/min [1.5 to 1.7 bbl/min] with circulating pump pressures of 24.1 to 27.6 MPa [3,500 to 4,000 psi], this part of the job required 36 hours and three jetting tools.

At 3,087 m, 60 m [197 ft] below the tubing and inside the 7-in. liner, the jetting tool was replaced with a PDM and a 2½-in. three-step mill. This final stage took 12 hours to clean out 43 m [141 ft] to 3,130 m [10,269 ft] and completely consumed the mill.

The total operation generated about 66,000 lbm [29,937 kg] of debris—6,000 lbm [2,722 kg] of scale and 60,000 lbm [27,216 kg] of abrasive particles—that were captured in the platform production separator. After the job, other platform wells had to be shut in for a short time to clean the production separator. Most scale-removal jobs now use a temporary separator to capture solids before they reach the production separator.

Scale Blaster technology effectively removed barium sulfate scale from completion tubing and hardware in conditions under which conventional methods had failed in the past. As a result, oil production increased 1,025%, which resulted in a 19-day payout.

It is common for wells in mature fields to experience scale deposition. Blaster services have been applied in several other locations to save time and money, including Duri field in Indonesia and several North Sea fields. In addition to use in wellbore cleanouts, CT has become an important tool in formation stimulation.

Reservoir Remediation

In Algeria, Sonatrach stimulates deep-pressure, high-temperature (HPHT) wells of the Hassi Messaoud field using coiled tubing-conveyed fracturing and new packer technology. Reservoir conditions allow low-rate, high-pressure hydraulic fracturing treatments, which significantly increase productivity and prolong the economic life of these wells. Unfortunately, many wells require remedial cement squeezes or tubing replacement to address tubular-integrity problems before stimulation operations can begin.

In the past, problems with conventional packers limited fracturing success because of differential pressures in excess of 9,000 psi [62.1 MPa] across the isolation packer. Some treatments resulted in costly fishing operations. CoiFRAC stimulation through coiled tubing treatments provided an alternative to conventional workover rigs (right). The availability of CT units was an additional advantage.

Coupled with more reliable mechanical packers for downhole isolation, CT-conveyed fracturing protects wellbore tubulars from high treating pressures and abrasive proppants. CoiFRAC techniques are applicable for initial stimulation treatments in new wells, stimulation of bypassed pay and restimulation of previously treated intervals.

In October 2001, Sonatrach performed the first CoiFRAC treatment in Hassi Messaoud Well OMP843. Completed with a 4½-in. cemented and perforated liner and 4½-in. tubing, this well had pressure between the 7-in. and 9½-in. casing. The CT packer was set at 10,660 ft [3,249 m] above a profile nipple in the production tubing. The treatment placed a total of 21,464 lbm [9,736 kg] of 20/40 proppant in the formation at a maximum concentration of 3.1 pounds of proppant added (ppa) per gallon of treatment fluid.

The average surface treating pressure was 8,600 psi [59.3 MPa]. A 13,100-ft [3,993-m] 2½-in. coiled tubing string isolated wellbore completion tubulars. The packer withstood a maximum 8,800 psi [60.7-MPa] differential pressure at 9 bbl/min [1.4 m³/min]. Prefracture production was 860 B/D [137 m³/d] of oil; postfracture production was 2,280 B/D [362 m³/d] of oil. The treatment, including deferred production, paid out in 39 days.

At that time, this was the deepest well fractured through coiled tubing. Excessive hydraulic forces caused the packer to release twice during prejob injectivity and treatment-calibration tests. Bottomhole pressure gauges verified the modeling of downhole forces and guided modifications to the CT packer.

Based on CoiFRAC experience from three Hassi Messaoud field wells, including Well OMP843, stimulated between October 2001 and January 2003, Schlumberger made several packer improvements. Development of the OptiSTIM MP mechanical packer for stimulation

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Because coiled tubing-conveyed fracturing often induces difficult-to-predict, variable loads and stresses greater than those normally encountered by stimulation packers, Schlumberger developed software to optimize treatment designs and reduce excessive packer loads. This software can also be used to monitor job progress and make necessary corrections in real time.

The new software and redesigned OptiSTIM MP packer were used on Well OML 862, an oil producer completed with 4 5/8-in. cemented production tubing and a 5-in. slotted liner. This well had communication between the 4 5/8-in. production tubing and 7-in. casing, and between the 7-in. and 9 5/8-in. casing strings. The cemented production tubing made a conventional workover impossible. Performing a fracture treatment through coiled tubing isolated the wellbore tubulars from high treating pressures and abrasive proppants.

With the packer set at 10,220 ft [3,115 m], a 10,000-gal [37.9-m³] calibration treatment pumped at 6.6 bbl/min [1 m³/min] and surface treating pressure of 9,400 psi [64.8 MPa] indicated a closure pressure of 10,300 psi [71 MPa], which gives a fracture gradient of 0.92 psi/ft [20.8 kPa/m]. The primary fracture treatment was pumped successfully at an average rate of 6.4 bbl/min [1 m³/min] with the packer set at 10,186 ft [3,095 m].

Sonatrach pumped 23,975 lbm [10,875 kg] of 20/40-mesh high-strength proppant at a maximum bottomhole concentration of 4 ppa, placing a total of 21,529 lbm [9,765 kg] in the formation. When a screenout occurred 24 bbl [3.8 m³] before the end of the flush, the pump rate was reduced to stay below the maximum allowable treating pressure of 10,000 psi [68.9 MPa].

The packer was then released and any remaining proppant was circulated out prior to retrieving the packer. The packer was exposed to an average differential pressure of 5,500 psi [37.9 MPa] and a maximum differential pressure of 9,600 psi [66.2 MPa] at screenout. The well is producing 65 m³/d [409 B/D] while Sonatrach optimizes the gas-lift system.

Fracturing through coiled tubing in Hassi Messaoud field required modified packers and improved computer software to model downhole forces. These improvements increased the reliability of CoiFrac treatments, which can now be performed in wells as deep as 12,000 ft [3,658 m]. Pumping rates can range from 8 to 25 bbl/min [1.3 to 4 m³/min] with 5 to 12 ppa.

CoiFrac technology can tap previously bypassed gas reserves and optimize well productivity, especially in low-permeability gas reservoirs. The latest OptiSTIM ST straddle packer provides added flexibility for selective isolation and stimulation of individual zones (next page, left). Reservoir applications from perforating to selective zonal isolation and stimulation have generated several new downhole CT tools.

Advanced Downhole Tools

Effective zonal isolation for CT applications requires inflatable packers that can pass through tubing, expand and then seal in larger casing. In the past, these systems were rarely used in hostile environments because of expansion limitations and susceptibility to high temperatures and pressures, and corrosive fluids or chemicals. Schlumberger developed the 2 1/8-in. single-element CoiPLACE HPHT high-pressure, high-temperature through-tubing inflatable anchoring packer to address the limitation of conventional inflatable packers (next page, right).13

CoiPLACE HPHT packers extend critical concentric zonal isolation to previously inaccessible downhole environments. These packers can be run in vertical, high-angle or horizontal wells on coiled tubing or on jointed pipe using a snubbing unit. This eliminates the need for a workover rig and allows remedial operations without killing the well.

Tapered slits in the tool body, or carcass, allow narrow sections near the end of a packer to provide the required load-bearing cross section, while the wider sections provide the necessary extrusion barrier and coverage for the inflation bladder. A CoiPLACE HPHT carcass restraint system (CRS), or internal crush sleeve, imposes a constant axial load on the slats during inflation that creates tension on the packer to ensure progressive inflation from the center toward both ends. This center-out inflation prevents end sections of the packer element from inflating first and trapping fluids, resulting in an inefficient seal, or soft set.

The proprietary elastomer and packer elements are resistant to hydrogen sulfide [H₂S], carbon dioxide [CO₂] and other chemicals. Steel parts in the 2 1/8-in. setting tool are replaced by nickel-based high-strength alloy components to make the entire BHA fully H₂S compatible. The composite elastomer bladder uses carbon fibers to eliminate axial strain and allows the packer circumference to expand freely.

This design provides a reliable seal at final-to-initial expansion ratios of greater than 3 to 1. CoiPLACE HPHT packers do not rely on a ball

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valve to initiate inflation. A large internal diameter allows high-rate fluid treatments. A 2½-in. CoilFLATE ST straddle tool version for stimulation applications uses the same principles as the CoilFLATE HPHT packer.

CoilFLATE HPHT packers can isolate wellbore sections for pressure testing, temporary zonal isolation and permanent abandonment. These chemically resistant systems can also be used for sand consolidation, acidizing and fracturing, as permanent and retrievable bridge plugs for water and gas shutoff, and as a cement retainer or packer for through-tubing gravel packing.

Selective stimulation with dual-seal straddle isolation tools. The OptiSTIM ST straddle packer for coiled tubing or jointed pipe comprises a straddle bypass, a straddle extension assembly with ported treatment sub and a multicycle dump valve. This configuration facilitates effective sequential placement of chemical, acid or proppant fracture treatments.

Inflatable packer expansion. Heavy-duty tapered slats, a high-strength carcass restraint system (CRS), a composite inflation bladder and a chemically resistant elastomer anchor CoilFLATE HPHT packers in place and provide a high-pressure seal even at large expansion ratios—2 to 1 at 5,000 psi [34.5 MPa] and 3 to 1 at 2,000 psi [13.7 MPa]. These packers withstand extended exposure at temperatures up to 375°F [191°C] in almost any chemical environment.
CoilFLATE HPHT packers were used recently for a deep, high-expansion, high-pressure cement retainer application in the Gulf of Mexico, a screenless sand-consolidation treatment in North Africa, and a high-pressure, high-temperature straddle packer for a stimulation treatment in the Middle East. In each of these applications, depth correlation was critically important.

The wireless DepthLOG CT depth correlation log is used for well logging, perforating, setting sand plugs, bridge plugs or mechanical packers, and for positioning straddle-isolation tools during selective stimulation treatments (right). This new tool combines a traditional casing collar locator (CCL) to detect magnetic variations at casing joints with pulse-telemetry technology that sends pressure signals to the surface.

Subsurface depth correlations are determined quickly and accurately by comparison with baseline well logs. Wireless technology decreases the number of trips into a well, saving up to 12 hours per operation on typical coiled tubing-conveyed perforating and stimulation operations. Flow-through capability provides unobstructed coiled tubing for pumping services and stimulation treatments. The ability to drop ball-type actuators through the DepthLOG tool allows setting or inflation of CT packers, activation or release of downhole tools, and detonation of perforating guns.

In Algeria, Sonatrach was first to use a CoilFLATE inflatable packer in combination with wireless DepthLOG technology. Remedial operations in Well MD 264 of the Hassi Messaoud field with two perforated zones required isolation and stimulation of an underperforming lower interval. To maximize workover economics, this acid treatment had to be conducted without a rig.

A separation of only 10 ft [3 m] between zones at a depth of about 10,000 ft [3,048 m] presented additional challenges. The packer had to be accurately positioned to isolate a high-permeability upper interval from the less permeable lower zone. An initial attempt without DepthLOG correlation resulted in packer inflation across the lower perforations and ineffective treatment-fluid diversion.

The DepthLOG tool was added to the BHA, which was run in the well to a point below the lower zone. Two upward passes while pumping fluid and receiving pressure pulses from the DepthLOG tool clearly indicated casing collar locations. The CoilFLATE packer was positioned at the target depth and inflated to an internal pressure of 4,000 psi [27.6 MPa].

Set-down weight on the coiled tubing verified complete packer inflation before pumping an acid treatment. This operation created a maximum differential pressure across the packer of about 3,500 psi [24.1 MPa], significantly higher than other inflatable packers can handle.

Immediately after completing the treatment, the packer was deflated, and nitrogen was pumped to flow spent acid back while pulling the coiled tubing out of the well. The production tubing did not have to be pulled and only one trip was required to achieve a sustained 326%
increase in oil production from 238 B/D [37.9 m³/d] to 776 B/D [123.4 m³/d].

Inherent advantages—fast trip times and continuous circulation without pipe connections, live well intervention with improved pressure control and a smaller footprint for reduced environmental impact—that make CT attractive for remedial wellbore and reservoir applications are also advantages for coiled tubing drilling.

**Reentry and Underbalanced Drilling**

Since 1991, coiled tubing has been used to construct thousands of vertical and directional wells. CT drilling applications include deepening, sidetracking and drilling new wells, especially for shallow gas reservoirs and gas-storage projects and environmentally sensitive locations. After a decade of profitable operations, four CT drilling applications have proved technically and commercially viable:

- new wells to about 3,000 ft [914 m]
- safety-sensitive operations
- through-tubing reentry
- underbalanced drilling.

CT drilling is ideally suited for underbalanced drilling. In depleted zones, drilling underbalanced minimizes formation damage and differential BHA sticking.¹⁵

Schlumberger drills and completes more than 100 wells per year with coiled tubing. The majority of vertical CT drilling activity occurs in Venezuela where 30 to 60 surface-hole sections are drilled and cased each year. A self-contained CT drilling barge, designed specifically to minimize the impact of encountering shallow gas zones in Lake Maracaibo, was commissioned in 1995.

Typically, this barge drills a 12¼-in. hole 1,000 to 1,800 ft [300 to 550 m] deep. Specialized equipment runs 9½-in. casing, executes cementing operations and conducts wireline logging. Schlumberger has constructed more than 275 vertical wells in Lake Maracaibo, each requiring an average of four days to complete.

Operations on the North Slope of Alaska, including the Prudhoe Bay field, represent one of the most successful CT drilling applications of the past decade, clearly demonstrating CT efficiencies and economics. Two fit-for-purpose hybrid CT drilling units operate continuously on the North Slope, each capable of drilling and completing three wells per month. A typical North Slope CT drilling well involves a directional through-tubing reentry to access bypassed oil (left). To date, more than 400 North Slope wells have been reentered using CT drilling technology.¹⁶
In April 2003, BP-Sharjah embarked on an underbalanced CT drilling program to perform through-tubing sidetracks from existing wells in the Sajaa gas-condensate field, United Arab Emirates (UAE). The objective was to improve well productivity and unlock additional reserves with multilateral wellbores connected to existing primary vertical wellbores.

Since initial production in 1980, reservoir pressure in the Thamama limestone reservoir at 12,000 ft [3,658 m] true vertical depth (TVD) declined from 7,900 psi [54.5 MPa] to less than 2,000 psi [13.8 MPa]. Considerable gas and condensate reserves remain, despite a significant 20% annual production decline in early 2003. The operator believed that overbalanced drilling had caused formation damage, resulting in extensive well cleanup. Recent horizontal rotary drilling programs had suffered massive, incurable lost circulation and severe differential sticking, which prevented some wells from reaching their geologic and drilling-length objectives.17

Underbalanced CT drilling operations were designed for wells previously completed with free-hanging 5-in. tubing inside vertical 7-in. casing.18 Plans called for setting flow-through, through-tubing whipstocks in 7-in. casing above existing perforations.

After milling a 3.8-in. casing-exit window, the CT drilling BHA—a specialized 3-in. wired CT drilling BHA attached to 2%-in. coiled tubing and wireline heptacable, a PDM designed for compressible fluids, and either a 3.75-in. polycrystalline diamond compact (PDC) or a 4.1-in. bicentered bit—would be used to drill underbalanced with nitrogen [N2] energized fluids. Three or more openhole laterals were to be drilled to access up to 10,000 ft [3,048 m] of additional reservoir per well (above). The initial phase of this campaign involved drilling 10 wells and 29 laterals with more than 66,000 ft [20,117 m] of new open hole. Up to five laterals have been drilled from a single exit window. Threefold production increases are common. In several wells, underbalanced CT drilling has increased production from about 5 MMcf/D [143,200 m³/d] to more than 25 MMcf/D [716,000 m³/d], limited by the flow restriction of 5-in. production tubing.19 These successes motivated BP-Sharjah to pursue additional CT drilling well candidates and extend the campaign. Schlumberger was recently awarded a two-year contract extension.

Directional hole sizes of 2%-in. and 4%-in. are considered optimal for CT load capacities, hole-cleaning fluid velocities and surface equipment specifications. However, 6-in. hole sizes and larger can be drilled under some conditions, particularly in vertical wells. Because of BHA limitations, directional CT drilling plans should target build rates less than 50° per 100 ft [30.5 m]. Exit-window depths and CT drilling lateral lengths should be evaluated on a case-by-case basis.

Schlumberger is advancing CT drilling technology worldwide through ongoing operations in Alaska, the Middle East, Venezuela and Indonesia.20 Over the past five years, average CT drilling lateral lengths have ranged from 1,500 to 3,000 ft [457 to 1,044 m]. With increasing activity, the CT drilling operating envelope continues to expand as evidenced by recent Schlumberger records:

- a 15,800 ft [4,816 m] whipstock casing exit in Colombia during 2002
- more than 9,000 ft [2,743 m] of open hole drilled underbalanced in a single reentry well in the UAE Sajaa gas field during 2003
- the deepest whipstock casing exit at 16,240 ft [4,950 m] and deepest total CT drilling reentry depth of 17,515 ft [5,339 m] in Alaska during 2004.

In April 2003, BP-Sharjah initiated reentry CT drilling operations from existing wells of the Sajaa gas field in the United Arab Emirates (left). The drilling configuration consisted of 2%-in. coiled tubing and a 3-in. BHA with a 4.1-in. bit. An inflatable whipstock was set above the perforations to mill a window in the 7-in. casing of the main wellbore. Plans called for at least three horizontal sidetracks in each well (right).
In addition to incremental production and improved reserve recovery, these worldwide CT drilling campaigns are yielding continual improvements in wellsite safety and operational efficiency.

**Accessing Lateral Well Branches**

In the past, reentry access to sidetracks from an openhole main wellbore (TAML Level 1 junction) or openhole drains and dropoff lateral liners in a cased well (TAML Level 2 junction) was not possible. This prevented remedial operations on individual laterals and precluded effective reservoir management. Schlumberger developed the Discovery MLT multilateral tool to selectively access all types of multilateral junctions using standard CT equipment.

The Discovery MLT tool provides CT-conveyed cleanout, stimulation, cementing and welllogging options for wells with previously inaccessible junctions and for multilateral completions without specialized diverter equipment. This acid-resistant tool operates solely on pressure and flow. Reentry operations are performed in a single trip into the wellbore.

A flow-activated bent-sub controls tool operation (above). Initially, the tool is indexed through 360° to establish the lateral orientation. After repeating this process to confirm the junction location, a pressure-telemetry signal to the surface confirms lateral access. Zakum Development Company (ZADCO) applied this technology in the Sajaa Field, Sharjah UAE.

### Multilateral well interventions

The corrosion-resistant Discovery MLT system includes a controllable orienting device to rotate the tool and an adjustable bent sub. Wellbore junctions are located by moving the tool, which is actuated by fluid flow, up and down across a target interval (1). When fluid flow exceeds a threshold rate, the lower tool section changes from straight to bent (2). Each actuation cycle rotates the tool 30°, producing a surface-displayed pressure profile that confirms lateral orientation (3). This system allows coiled tubing to selectively access any type of lateral for well cleanouts, logging, perforating, stimulation and cementing (4).

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5. Multilateral wells are classified according to definitions established during the Technical Advancement of Multilaterals (TAML) Forum held in Aberdeen, Scotland, July 26, 1999 and recently updated in a July 2002 proposal that was approved in 2003. These standards characterize wellbore junctions as Level 1, 2, 3, 4, 5 or 6 based on degree of mechanical complexity, connectivity and hydraulic isolation.
tool in the UAE. Multilateral completions in the Upper Zakum field tap several reservoir layers with as many as 12 laterals drilled from a single main wellbore (above).

Previously, remedial access to individual branches was not possible, which prevented effective stimulation and production logging of individual laterals to evaluate treatment results and monitor production. Acid had to be bullheaded—pumped from surface—down wellbore tubulars or coiled tubing with the end of pipe near a lateral entrance.

The majority of the acid reaction occurred at the entrance of the openhole section, leaving the remainder of the lateral branch untreated. This practice also created large voids that could collapse and prevent future access to the lateral or restrict production. ZADCO successfully acidized openhole laterals in two offshore wells using Discovery MLT technology.

In the first use of this tool, ZADCO performed a selective treatment in one lateral of a well with four branches. In a second well, two of the five laterals were treated individually. These jobs took seven days—four days of operations and three days of mobilization, demobilization and weather delays—and cost 65% less than using a drilling rig. Production increased by 11% in the first well and 30% in the second well, which paid back the investment in two days.

The Discovery MLT tool has proved to be a simple, cost-effective lateral reentry solution that helps maximize the productivity and performance of multilateral wells. In another UAE well for a different operating company, the Discovery MLT system helped selectively cement a lateral and shut off water production utilizing coiled tubing.

In Oman, Petroleum Development Oman (PDO) successfully performed production logging in a Saih Rawl field multilateral well. PDO selectively reentered and logged three lateral branches to determine the water-injection profile and identify possible fractures in the formation.
The advantages and economics that make CT attractive for drilling and remedial interventions also apply for well completions. For example, techniques for running an electrical submersible pump (ESP) on coiled tubing expand artificial-lift options for remote locations with limited rig availability, for areas with high workover costs and for offshore wells.

Artificial Lift
A CT-deployed ESP lifts fluid through the coiled tubing or up the annulus around a coiled tubing string. Prior to being purchased by Schlumberger, CAMCO company REDA installed the first submergible pump on coiled tubing in 1992 and the first coiled tubing ESP and power cable system in the UK in 1994. Today, REDACoil submergible pump technology installs and supports the ESP power cable inside 2-in. or 2 3⁄8-in. coiled tubing (right).

The self-supporting Friction Deployed submergible pump power cable minimizes CT unit and installation costs. The cable is no longer banded to the coiled tubing during deployment at a wellsite, but remains protected in an inhibited fluid. The coiled tubing can also be used as a hydraulic conduit for pressure actuation of packers, subsurface safety valves or other downhole equipment.

Controlling wells with kill-weight fluids prior to an ESP installation is expensive and time-consuming, and often results in lower well productivity because of formation damage. The REDACoil system allows for quick, safe coiled tubing deployment into a well under pressure. Placing the power cable inside coiled tubing assures a secure seal within the BOP and stripper head during installation.

Recent advances in REDACoil technology, including internal power, data and fiber-optic cables, have made it possible to produce high flow-rate wells at up to 20,000 B/D [3,180 m³/d] of fluid inside 7-in. casing. For well conditions that do not allow flow up the casing, placing a REDACoil system inside 7-in. production pipe isolates produced fluids from both the 9 5⁄8-in. well casing and the ESP power cable.

REDACoil technology has a proven record with more than 20 installations worldwide. Anadarko Petroleum has installed 12 REDACoil completions in Qatar. These systems were bottom-intake configurations with annular production. These wells have 9%-in. casing at about 4,000 ft [1,219 m] TVD with 4,000 to 6,300 ft [1,290 m] MD. The maximum well inclination at pump depth is 86°.

The current REDACoil configuration consists of 2%-in. coiled tubing with internal power cable, a REDA lower connector, motors, universal motor base, protector, discharge head, pumps, intake and thrust protector. The 150-ft [46-m] BHA is installed inside a 7-in. liner. Fluid production ranges from 8,000 to 12,000 B/D [1,272 to 1,907 m³/d] with only about 100 Mcf/D [2,864 m³/d] of gas. The BHT is 155°F [68°C]. The lower completion contains a deep-set downhole safety valve, sliding sleeve, permanent pressure and temperature gauges and chemical-injection mandrels.

On other REDACoil installations a mechanically activated FIV Formation Isolation Valve may also be included. This ball-type valve is actuated by a stinger at the bottom of the REDACoil assembly to allow underbalanced deployment of the ESP. It is also possible to add a Phoenix MultiSensor system for continuous downhole data-gathering. This sensor monitors pump and well parameters and transmits data through the power cable.

Offshore, CT expands ESP applications when through-tubing installation is feasible, eliminating the need for conventional rig workovers and minimizing downtime as well as deferred production. This unique, flexible technique has potential in small or marginal offshore fields where no gas-lift infrastructure exists or where conversion from gas lift to ESP is required.

In the South China Sea Magpie field of Southeast Asia, Shell Brunei installed two offshore REDACoil completions similar to those in Qatar except for using 2-in. instead of 2 3⁄8-in. coiled tubing. The well depth is 3,400 to 3,800 ft [1,036 to 1,158 m] with well inclinations of 60 to 65°. REDACoil equipment is the same as that used in Qatar, but the pumps have lower fluid-volume output.

Shell selected the REDACoil system to meet workover cost objectives when converting from gas lift to ESP as the field matured. Combined with technologies like an advanced gas handler and additional mechanical barriers, the REDACoil system reduced costs and increased oil production in two wells. Production from the first REDACoil installation, Magpie Well 14, increased to 2,201 B/D [350 m³/d], 56% more than the gas-lift design of 1,415 B/D [225 m³/d].

In the second well, ESP production increased to 4,560 B/D [725 m³/d], 32% more than the 3,459 B/D [550 m³/d] with a gas-lift design. Shell estimates that converting from gas lift to ESP will recover an incremental 3.4 million bbl [540,000 m³] of oil from the first well and 2 million bbl [318,000 m³] from the second. The REDACoil system in Magpie Well 14 continues to operate after more than 4 ½ years.

In almost every area of oil and gas activity, CT is a firmly established technology for remedial well interventions and the drilling and completion of new wells (previous page and right). CT allows selective placement and accurate controlled delivery of chemical, acid and fracturing treatments. It is also used to clean, protect or replace existing tubulars. CT versatility is especially valuable in wellbores with questionable tubular integrity, or wells requiring flow conformance for water and gas control, and also for sand control. CT services can be executed efficiently under almost any condition, including live wells, while ensuring optimal well control. In addition, CT allows real-time communication with downhole tools conveyed to control treatments, manipulate hardware and analyze reservoir properties. This technology has proved effective for developing low-permeability, low-pressure and mature or depleted reservoirs in which conventional techniques fail to achieve commercial production.

Upgrading existing tools and techniques while developing new technology remains a key to CT success as does improving our understanding of coiled tubing behavior and risk assessment. Combining multiple systems or processes yields new and unique solutions to old well-intervention challenges. For example, Schlumberger has made further advances in systems for operating CT units from anchored floating vessels and platforms, and recently field tested a new through-tubing gravel-pack system with reentry capabilities.

Deeper, higher pressure, higher temperature and extended-reach wells increase the complexity of CT operations. In 1995, Schlumberger began using simulators in training centers at Kellyville, Oklahoma, USA, and Bottesford, England, to familiarize employees with CT equipment, operations and contingency procedures. Capitalizing on extensive simulator experience and continual improvement in portable computer capabilities, Schlumberger followed this with development of portable simulation-based training.

The resulting CT Sim computer-based learning resource presents concepts, equipment functionality and operating procedures. The intent was to provide prerequisite knowledge and practice in order to optimize training at the learning centers or in field locations. Scheduled for release in 2004, the CT Sim program will be a key component for training and recertification of CT supervisors and engineers.

Schlumberger continues to develop and refine equipment, procedures and techniques to extend the operating pressure ranges for CT jobs, including high-pressure applications up to 13,500 psi [93.1 MPa]. Also in development are spoolable CT connectors and completion equipment, including gas-lift valves, which will facilitate operations in logistically challenging areas, such as mature offshore platforms and remote or environmentally sensitive locations.

However, not all well-intervention applications involve pushing the limits of CT tubular capabilities, equipment and tools. CT continues to be a workhorse for many conventional well operations and services. Petroleum Development of Oman (PDO) used CT to optimize plug and abandonment (P&A) practices.

Rigless methods with new cement and sealant technologies minimize costs while ensuring long-term environmental protection in these once prolific oil wells. CT saved up to 30% compared with P&A campaigns using conventional drilling and workover rigs. This represented a total savings of more than US$ 5 million in a recent 60-well program.

As CT reliability improves, operators are reevaluating candidate wells and targeting more completions for through-tubing or concentric remedial interventions, including some wells previously considered too risky for CT operations. To that end, CT equipment and string reliability continue to be the focus of efforts to reduce downhole risks and decrease operational failures.

Schlumberger is committed to maintaining technical leadership in CT services through cost-effective solutions that address operator needs from the most basic to the most complicated applications, with skilled personnel to implement them. The goal is to assure optimal well and reservoir performance through safe and efficient operations.

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