Coiled Tubing: Innovative Rigless Interventions

Reentry drilling, reservoir stimulation and wellbore recompletions often need to be performed without rotary rigs or conventional workover units as a means of maximizing production economics. Coiled tubing allows remedial operations to be performed under pressure, or “live” conditions, without pulling well tubulars. Collaboration between operators and providers of this technology continues to yield tools and techniques that improve productivity in both new and mature fields.

Many operating companies are turning to through-tubing, or concentric, operations to solve difficult production problems and to meet demanding well-intervention or wellbore-recompletion challenges. Steeply declining production output and insufficient replacement of oil and gas reserves have compelled operators to reexamine field-development strategies and reservoir-management efforts. Increasingly, asset managers need to optimize the performance of both new and existing wells to meet global demand for petroleum.

Long strings of relatively small-diameter steel pipe, or coiled tubing, can be mobilized quickly to drill new wells or reenter wells through existing wellbore tubulars. This technology also is used to perform initial completions, remedial interventions and workovers, or recompletions. Compared with conventional rotary drilling, workover and snubbing units, coiled tubing spooled onto a reel for transport and the associated surface equipment for deployment and well insertion offer several advantages.

Increased efficiency comes through continuous pipe deployment and retrieval under pressure, or “live” conditions, without having to control, or kill, a well. In addition, there is no need to pull production tubulars from the wellbore and perform downhole operations by rerunning individual joints of a conventional workstring with threaded connections.

The capability of working under pressure and the unique ability to pump fluids at any time, regardless of coiled tubing depth or direction of travel in a wellbore, offer distinct benefits and operational flexibility. Compared with wireline or slickline, coiled tubing provides relatively high load capacities for deeper vertical or extended high-angle reach, and for greater tensile capacity, or overpull, downhole.

These capabilities facilitate wellbore cleanouts; jetting or lifting wells with inert gases or lighter fluids; perforation washes; acid and hydraulic fracturing stimulations, sand-consolidation or sand-control treatments; cementing; fishing or milling; and both directional and underbalanced drilling. Installing wireline, data or power cables inside a string of coiled tubing allows real-time well logging, downhole monitoring and control, measurements while drilling and operation of electrical submersible pumps.

Using application-specific downhole systems, coiled tubing concentric operations are helping operators increase well and field productivity throughout the entire life cycle of producing reservoirs. Even under adverse economic conditions and harsh subsurface operating environments, coiled tubing facilitates cost-effective interventions that can optimize hydrocarbon output from wells, increase reserve recovery from reservoirs and greatly improve field profitability.

Coiled tubing is a viable alternative in many demanding applications that must be performed without a rotary drilling rig or workover unit to maximize profitability. New integrated systems and innovative combinations of tools and techniques have been keys to recent success using coiled tubing in several specialized applications.
This article begins with an overview of coiled tubing equipment and practices that are being used for underbalanced drilling in the Middle East. We then present a new downhole system that was used to locate and stimulate individual lateral branches of multilateral wells in Canada. That discussion is followed by a case history from Algeria demonstrating selective isolation and stimulation of closely spaced intervals. The article concludes by presenting a methodology for performing multiple through-tubing operations during a single rig-up and wellsite operation.

Underbalanced Reentry Drilling
The Sajaa field in the United Arab Emirates (UAE) produces from a deep, low-pressure carbonate reservoir. Amoco, now BP, drilled the first wells in this prolific gas field during the early 1980s. Initial development activity involved about 40 vertical wells drilled with overbalanced pressures by conventional methods. Later, many of these wells were recompleted with cemented 7-in. liners tied back to surface and 5-in. production tubing without a downhole packer (right).

During the 1990s, BP Sharjah sidetracked a few of these wells using rotary rigs and underbalanced drilling techniques. More recently, this experience was helpful during planning and implementation of a new infill drilling campaign. As reservoir pressure and well productivity declined, BP needed to access reserves in areas that were not being drained effectively by the original wellbores.

A team of BP personnel from North Slope Alaska operations, Houston Engineering Technical Practices (ETP), UK ETP, Sunbury Research and Sharjah engineering and operations groups evaluated several methods for reentering wells and drilling underbalanced. They found coiled tubing to be the best option. In March 2003, BP Sharjah began drilling multilateral sidetracks from existing wellbores using coiled tubing for underbalanced operations.^2

The BP team chose 2%/-in. outside diameter (OD) coiled tubing with an internal wireline cable as a means of continuously transmitting downhole data and measurements to surface. Initially, BP used an 80,000-psi [552-MPa] yield strength, uniform wall thickness tube that could be swapped end for end, or reversed, on the spool.

^Typical wellbore configuration in the Middle East Sajaa gas field. BP Sharjah Oil Company initiated coiled tubing underbalanced reentry drilling operations from existing wellbores in the Sajaa gas field of the United Arab Emirates (top). Most of these wells had been recompleted with cemented 7-in. liners tied back to surface and 5-in. production tubing (bottom left). A few wells were reentered in the 1990s to drill lateral sidetracks with conventional rotary rigs and underbalanced drilling techniques (bottom right).

to extend fatigue, or usable, life. This string design evolved to a 90,000-psi [620-MPa] yield tapered-wall tube with high yield strength and sufficient hydrogen sulfide \( \text{H}_2\text{S} \) resistance. The footage that could be drilled with these tapered strings was found to be acceptable even though the tapered strings could not be reversed.

Tapered strings minimize loads on the surface injector head, reduce pickup weights during normal operations and increase available overpull downhole in stuck-pipe situations. Less weight on bit (WOB) is available for drilling compared with the uniform-wall strings, but this has not been a disadvantage because of the relatively soft formations in this area and successful efforts to optimize bit performance.

Most laterals are limited in length because the pickup weight at total depth (TD) becomes too high, not because of limited WOB. In addition, drilling longer laterals may be restricted by increased friction pressures while drilling, which cause a higher equivalent circulating density and a degree of overbalance at the bit that formations can no longer tolerate.

A coiled tubing drilling tower built specifically for Sajaa field operations supported the coiled tubing injector; the wellhead and blowout preventer (BOP) stack supported the weight of the coiled tubing string (right).

The tower work decks were positioned for easy access to BOP systems, which provide dual barriers while deploying tools under pressure and drilling underbalanced. The BOP system also provides two mechanical barriers during nonroutine events, such as elastomer-seal failures or leaking BOP rams, and other minor contingencies.

A hydraulically operated choke manifold on the fluid-return line controls flow from the wellbore and downhole pressure during drilling operations. This manifold is fitted with redundant isolation valves for each of the two chokes to maintain constant flow even if one side becomes plugged or inoperable. All of the common drilling contingencies and well-control situations that have occurred have been handled safely using these surface systems.

If gas went directly to the pipeline, high line pressure might preclude underbalanced operations on many Sajaa field wells. Therefore, produced gas from returning fluids is sent to a vertical flare stack or to a compression system. Sending gas to the Sajaa processing plant while drilling minimizes lost or deferred production.
The bottomhole assembly (BHA) for underbalanced drilling is a 3-in. OD, wired assembly powered from the surface through a wireline cable inside the coiled tubing (left). This BHA includes two upper and two lower ball valves that can isolate both wellbore pressure and coiled tubing pressure. The upper valves eliminate the need to bleed pressure from the coiled tubing every time a BHA is assembled or disassembled.

A downhole data system acquires pressure, temperature, WOB, lateral and stick-slip vibration, gamma ray, casing collar location, azimuth and inclination measurements. BP also has used a resistivity logging tool with multiple depths of investigation while drilling some of the wells.

To reduce vibration-related failures, Baker Hughes Inteq moved electronic components in the BHA away from the downhole motor and switched from bicentered 4¼-in. polycrystalline diamond compact (PDC) bits to 3½-in. gauge PDC bits. The gauge bits provided a higher rate of penetration (ROP) and less vibration without adversely impacting borehole size and well productivity. Engineers also monitored lateral and axial vibrations closely, and reduced injection rates to minimize BHA vibrations during hole-cleaning, or wiper, trips.

These measures reduced BHA failures caused by excessive vibrations when drilling with two-phase liquid and gas. A BHA can now operate for several days to more than a week at a time. BP uses a 2¼-in. air-drill motor (ADM) with an excellent performance history, so motor failures are rare. BP and Baker Hughes Inteq optimized the rotor-stator clearance and materials used in these motors to extend ADM operating life under harsh wellbore conditions. The longest motor run to date lasted more than 12 days and drilled 9,763 ft [2,975 m].

BP drills with underbalanced pressures using nitrogen [N₂] and fresh water with a biodegradable friction reducer to reduce pickup weights and pumping pressures. Typically, BP drills three or more multilateral sidetracks, each about 3,000 ft [914 m] in length, through a single casing-exit window (next page).

Milling windows with through-tubing, inflatable whipstock assemblies has been the most challenging part of this project, and the one that has improved the most. Optimized milling techniques resulted in better casing-exit windows to allow easier passage of 3¼-in. gauge PDC bits. BP also developed a molded resin cap, which disintegrates during the first few minutes of drilling, to guide bits through a casing window.

^ Coiled tubing bottomhole assembly (BHA) for underbalanced drilling in the UAE. The BHA used for underbalanced reentry drilling in the Sajas field includes dual upper and two lower ball valves to isolate both wellbore pressure and coiled tubing pressure. This eliminates the need to bleed internal pressure from the coiled tubing every time the BHA is assembled or disassembled. It also includes sensors to acquire internal and external pressure, external temperature, weight-on-bit (WOB), lateral and stick-slip vibration, casing collar locator (CCL), directional azimuth and inclination, and gamma ray measurements. Baker Hughes Inteq positions electronic components in the BHA as far as possible from the 2½-in. downhole air-drill motor (ADM). In addition, BP now uses a 3½-in. gauge polycrystalline diamond compact (PDC) bit instead of a bicentered 4¼-in. PDC bit to reduce downhole vibrations and related BHA failures.
The BHA for this project was designed for openhole drilling and could not survive for long under the severe vibrations of milling windows using liquid and gas. Therefore, BP initially performed milling operations with single-phase liquids, but this often resulted in the loss of large volumes of water to the formation. In some wells, excessive losses made it difficult to reestablish well flow and underbalanced conditions when it was time to start drilling a sidetrack because the surrounding formation was saturated, or loaded, with water.

In wells that will not tolerate excessive fluid losses, BP mills casing windows using liquid and gas two-phase drilling fluids and PDC bits specifically designed for milling with no electronics in the BHA. BP has successfully milled five 3.8-in. windows in underbalanced conditions using two-phase fluids without downhole pressure sensors.

BP shuts wells in before mobilizing the coiled tubing unit to allow the near-wellbore pressure to build up. Extremely low-pressure intervals require longer shut-in periods to achieve and maintain underbalanced conditions. In this way, available reservoir pressure is conserved for as long as possible while drilling. As lateral drilling proceeds and frictional pressures increase, additional reservoir pressure must be encountered to ensure underbalanced conditions.

In areas of the reservoir with higher pressures, BP maintains underbalanced drilling conditions by manipulating the choke manifold at the surface. At some point, however, bottomhole pressure exceeds reservoir pressure and drilling becomes overbalanced from that point on. If the formation permeability is low enough to tolerate some degree of overbalance, drilling can continue to extend the lateral branches as far as possible.

While drilling with slightly overbalanced pressure, engineers limit the ROP, make shorter wiper trips to remove excess cuttings, reduce fluid injection rates and minimize or eliminate N₂ foam sweeps to avoid additional increases in pressure. BP continues drilling until the overbalance gets too high, pickup weights get too close to the coiled tubing yield strength, or there is no additional forward penetration.

Using these techniques, BP Sharjah has reentered 37 wellbores and drilled more than 150 lateral sidetracks with a combined footage that exceeds 300,000 ft [91,440 m]. To date, the longest single lateral drilled has been 4,350 ft [1,326 m], and the most footage drilled during a single reentry has been 14,487 ft [4,416 m] with eight laterals. Accessing reserves that were not being drained by the original wellbores reduced the production decline in Sajaa field, significantly extending the life of this field.

From health, safety, cost and environmental perspectives, this program also has been extremely successful. During more than two and a half years of drilling, encompassing more than 1 million staff-hours of work, there have been no lost workdays.

In the early phases of this project, BP encountered rig-up, equipment and operations problems that required 79 days to complete the first well. Wells are currently drilled in only 20 to 30 days. Rig moves, which initially took almost nine full days, now require only 2.5 days.

BP maintains an extensive database that facilitates knowledge sharing and continuous improvement by capturing operational practices and experience from each contractor. The database includes everything from rigging down, rig moves and rigging up, to milling casing-exit windows and drilling laterals.

Multilateral wells maximize wellbore contact with a reservoir, increase well productivity and optimize reserve recovery. However, production enhancement and maintaining well productivity in these types of completions require cost-effective methods for performing stimulation treatments. In addition to reentry drilling, coiled tubing also plays a vital role in wellbore remedial operations and reservoir stimulation treatments for multilateral wellbores.
Multilateral Well Stimulation

Talisman Energy drills wells in the Turner Valley field of Alberta, Canada, that consist of a main wellbore and two or more horizontal openhole laterals targeting porous, upper and lower geologic units of the dolomitic Rundle formation. Remedial operations in these wells traditionally were inefficient, ineffective and expensive. Engineers needed an effective means of conveying acid into the individual well branches to optimize production from multilateral completions.\(^1\)

Previous methods of blindly searching for and randomly accessing laterals often left Talisman and other operating companies in this area uncertain about the effectiveness of cleanout operations and acid treatments. Schlumberger integrated two technologies—the Discovery MLT multilateral tool and the Jet Blaster jetting scale removal service—to access and stimulate individual lateral branches without the need for complex, permanent well-completion equipment.

Initially, producers in this area performed stimulation treatments on multilateral wells in several steps. They made separate runs with two different BHA configurations, hoping to randomly access each lateral. The Jet Blaster service was used during the first run to scour the borehole wall with a high-energy fluid jet and reconnect with the rock-matrix permeability (above left).

A second run followed with a flexible BHA that had different bend angles than the natural curvature at the lower end of the coiled tubing. The disadvantage of this “hunt-and-hope” approach was that operators had no control over which lateral the BHA would enter, so the same well branch might get treated twice.

Even when applied repeatedly, this method did not significantly improve well productivity. Subsequently, companies began using a jetting tool only during the first run followed by a second run without the jetting tool, using only a Discovery MLT tool to locate and treat individual laterals (left).

This technique routinely accessed the second lateral in one run, but only the first lateral was optimally treated with the high-energy rotary jetting tool. Operators considered the benefit of mechanically removing damage with a high-energy fluid jet in just one branch worth the cost and risk of making multiple runs.

In wells with closely spaced laterals, there was still uncertainty about which lateral had been accessed, especially if measured depths were within about 50 ft [15 m] or if helical

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lockup of the coiled tubing occurred. There also were the possibilities of treating a lateral twice or not at all. To address these problems and to facilitate effective stimulation of multilateral wells, Schlumberger developed an integrated lateral-locating and rotary jet-wash tool.

This new Blaster MLT multilateral reentry stimulation and scale removal system combines the capabilities of a Discovery MLT tool and a Jet Blaster tool. This unique system can access all of the lateral branches in a well to convey acid and scour the borehole with a high-energy fluid jet. Several laterals can be treated in a single trip, which reduces job time at the wellsite.

Qualification testing and verification of Blaster MLT system capabilities were performed at the Schlumberger Reservoir Completions (SRC) Center in Rosharon, Texas. Various tests were conducted to determine operating parameters, develop treatment procedures and correlate a theoretical model that aids in predicting tool performance at specific flow rates. Engineers ran the system in a 7,000-ft [2,134-m] test well to compare surface test results with actual downhole performance data and were able to predict operating flow rates with reasonable accuracy.

Schlumberger also performed a series of rigorous flow-loop tests, ranging from 10 to 12 hours, to evaluate the durability of this system. During extended operating periods, injection rates were increased and decreased while pumping fresh water, N_2 or fluids foamed with N_2. The Blaster MLT system performed within the initial design parameters without any tool failures.

Talisman Energy performed stimulation treatments in two similar wells of the Turner Valley field, one with a Jet Blaster tool followed by a Discovery MLT tool and the other with the new integrated multilateral jet-wash tool. The Blaster MLT system was run in a multilateral well to perform separate acid treatments in each lateral branch during a single trip into the wellbore.

This newly drilled openhole completion consisted of a main borehole and two lateral sidetracks. The true vertical depth (TVD) of this well was 8,888 ft [2,709 m]. The longest lateral leg extended to 11,387 ft [3,471 m] measured depth (MD). The multilateral jet-wash tool was run into each openhole lateral.

The lateral-locating mechanism was not required to enter the first well branch. However, the Blaster MLT tool was activated to locate and access the other two branches. Lateral access and tool location were verified by correlating the TVD and MD of each branch, which confirmed the functionality of the Blaster MLT system (above).

After the bottom of each lateral was reached, the BHA was slowly pulled back to the entry point while the high-energy jet-wash component scoured the borehole wall. Sharp increases in circulating pressure confirmed continuous jetting action throughout each lateral. Injection pressures and flow rates indicated that the system performed as expected. Treating fluids were effectively conveyed to the formation with no downtime.

At the top of each lateral, the fluid injection rate was reduced to zero to equalize the internal tool pressure with the wellbore pressure. After all three laterals were treated, the BHA was pulled into the intermediate casing to purge the tool and tubing, and to lift the well with N_2. Schlumberger found no indications of tool failure or wear when the system was inspected at the surface.
The Blaster MLT system ensured lateral access and reduced the number of trips into this wellbore from three to one, which resulted in a 50% reduction in time required at a wellsite. Talisman Energy successfully treated four other wells, and believes that the multilateral jet-wash system will aid production optimization efforts in the Turner Valley field and other area fields. Each of these jobs, including rig-up and rig-down, were completed in about 48 hours.

New multilateral wells can be treated effectively and existing underperforming wells can be reentered to enhance production and hydrocarbon recovery. Exploratory wells with openhole sidetracks and multilateral completions in low-permeability formations now can be stimulated more effectively to better evaluate, characterize and produce a reservoir.

Combining coiled tubing tools and techniques also provides novel solutions in other stimulation and remedial applications, including selective zonal isolation and diversion of hydraulic fracturing or acid treatments.

**Accurate Zonal Isolation**
Sonatrach needed a reliable, rigless technique for isolating and selectively stimulating closely spaced perforated intervals in the Hassi-Messaoud field, Algeria. This North African field produces from a thick sandstone at about 3,300 m [10,827 ft] with four distinct reservoir intervals and a transition zone. Most of the wells have cemented liners with multiple perforated intervals.

Traditionally, Sonatrach circulated oil-base fluids to control these wells prior to any well-intervention operations, which often resulted in near-wellbore formation damage. This operator performs about 50 acid stimulations each year to remove damage and restore or optimize well productivity.

Well MD 264 was producing from two perforated intervals: a hydraulically fractured upper zone and two deeper, low-permeability zones that were underperforming (below left). Only 3 m [10 ft] of unperforated casing was available from 3,430 to 3,433 m [11,253 to 11,263 ft] between the upper and lower underperforming intervals.

This well, which was drilled to 3,503 m [11,493 ft] and completed open hole in the late 1970s, initially produced 329 m³/d [2,060 bbl/d].

![Concentric zonal isolation and selective stimulation. Sonatrach wanted to isolate an upper hydraulically fractured zone in Well MD 264 of the Hassi-Messaoud field, Algeria, without killing the well. This would allow selective stimulation of a lower perforated interval with hydrofluoric (HF) organic acid. Through-tubing treatment success depended on using coiled tubing to set an inflatable packer in a 3-m [10-ft] section of unperforated casing between the two intervals.](image1)

![Inflatable coiled tubing packers. Heavy-duty tapered slats, a high-strength carcass restraint system, a composite inflation bladder and a chemically resistant elastomer element anchor CoilFLATE high-pressure, high-temperature (HPHT) packers in place and provide a high-pressure seal even at large expansion ratios—a 5,000-psi [34.5-MPa] differential at a 2 to 1 expansion and a 2,000-psi [13.7-MPa] differential at a 3 to 1 expansion. These packers withstand extended exposure at temperatures up to 375°F [191°C] in almost any chemical environment. The 2¼-in. OD CoilFLATE HPHT packer can expand to more than three times its initial OD and can set in casing sizes up to 7½-in. OD. After expansion, these packers allow injection above and below the packer or both. Hollowing a stimulation treatment and while still connected to the coiled tubing, the packer can be deflated back to approximately its original 2½-in. OD for retrieval through wellbore restrictions of about 2.205 in.](image2)
In the mid-1990s, Sonatrach installed a cemented 4 1/2-in. liner and perforated the upper interval from 3,406 to 3,418 m [11,175 to 11,214 ft]. That zone failed to produce economically even after proppant fracture stimulation. Sonatrach added perforations from 3,421 to 3,464 m [11,224 to 11,365 ft], which produced 57 m³/d [389 bbl/d] after an acid stimulation. A pressure buildup test and a NODAL production system analysis indicated a high positive skin, or formation damage, and a potential undamaged productivity of 94 m³/d [602 bbl/d]. Sonatrach wanted to selectively treat the lower perforated intervals from 3,433 to 3,464 m [11,263 to 11,365 ft] with hydrofluoric [HF] organic acid.

To avoid further damage from killing the well, engineers decided to perform this treatment through the existing production tubing using coiled tubing and an inflatable packer to isolate the upper hydraulically fractured interval. Treatment success depended on accurately setting the packer.

If the packer were set too high, treatment fluid might take the path of least resistance and divert into the upper previously fracture-stimulated zone; if set too low, a large part of the lower perforated interval might not be treated, increasing risk of damage to the outer packer elements and internal bladder, which might prevent inflation.

The inflatable packer had to withstand high differential pressures across the packer without leaking or failing because the deeper, low-permeability intervals might require treatment injection pressures as high as 3,500 psi [24 MPa], even at minimal pumping rates. Sonatrach used the CoiFLATE coiled tubing through-tubing inflatable packer, which was designed to withstand harsh downhole wellbore conditions and corrosive treatment chemicals under extended periods of exposure at up to 375°F [191°C] (previous page, right).

An initial attempt to position and inflate the packer without real-time downhole depth correlation failed, reinforcing the need for accurate depth correlation. Sonatrach could not inject fluid after setting the packer based on surface measurements of coiled tubing length, which only have an accuracy of about 10 ft/10,000 ft [3 m/3,048 m]. Packer damage after retrieval indicated that the packer had been set across a perforated interval.


Sonatrach considered two methods for correlating downhole depths and positioning the packer. One method was coiled tubing with an internal wireline cable to transmit data from downhole logging tools, and the other was a memory log. Coiled tubing with wireline provides real-time depth correlations, but adds operational complexity, risk and cost. In addition, acid stimulations cannot be performed unless armored cable with a special plastic coating is installed.

Memory logging requires an extra trip to retrieve data from the downhole memory and does not provide real-time depth correlations. It also relies on computer modeling to estimate coiled tubing length because running in and out of the wellbore plastically deforms and stretches the coiled tubing. To achieve an increased level of accuracy on the second attempt, Sonatrach used the DepthLOG CT depth correlation log (above).

This wireless casing collar locator (CCL) system with pump-through capability provides accurate, real-time depth measurements, allows pumping of corrosive fluids and is compatible with the CoiFLATE high-pressure, high-temperature (HPHT) packer as an add-on assembly.
The tool sends telemetry pulses to the surface through fluid in the coiled tubing and outputs an instantaneous and continuous CCL log without the need for a wireline cable inside the coiled tubing. A real-time depth correlation log allowed Sonatrach to accurately position the packer between the two perforated intervals.

Combining these two innovative technologies in a modular toolstring met all operational objectives of this demanding application. During a single run into the well with coiled tubing, Sonatrach could acquire a CCL log for accurate depth correlation and optimal packer placement in the 3-m casing section, set and inflate the CoilFLATE HPHT packer, pump the HF acid treatment, deflate the packer and initiate well flow by injecting nitrogen.

The DepthLOG CT system required a minimum fluid rate of 0.5 bbl/min [0.08 m³/min] to produce a positive pressure signal at the surface. An additional 0.5 bbl/min was needed to keep the coiled tubing continuously full of fluid. Surface testing verified that the pressure pulses and flow rates required to generate wireless CCL signals would not cause premature inflation of the CoilFLATE packer.

At the well location, an initial coiled tubing run used the high-pressure Jet Blaster tool to pump nitrified fluids and clean the production tubulars. This operation confirmed clear passage to the packer setting depth, cleaned the perforations to ensure optimal acid penetration and removed any possible debris and scale buildup from the casing walls where the packer was to be set.

Schlumberger performed two DepthLOG correlation logs to accurately position the CoilFLATE packer within the 3-m casing section. Sonatrach confirmed packer inflation and anchoring by setting coiled tubing weight down on the packer and performed an injection test to confirm a positive seal before pumping 120 bbl [19.1 m³] of HF acid foamed with N₂. The stimulation treatment was pumped in two stages, each consisting of a hydrochloric [HCl] acid preflush, HF acid stage and HCl overflush stage, with a chemical diversion system between each stage.

The inflatable packer was designed to withstand high differential and injection pressures, so it was possible to pump this treatment at 3,500 psi [24 MPa] and still maintain a margin of safety to avoid packer failure. Formation injectivity increased from 0.2 to 1 bbl/min [0.03 to 0.16 m³/min] while maintaining a constant wellhead pressure, indicating no packer leakage and confirming that the acid was dissolving formation damage, opening the perforations and reducing skin.

After Sonatrach completed this treatment, overpull was applied to the coiled tubing at the surface to deflate the CoilFLATE packer. Nitrogen was then circulated through the coiled tubing to reinitate well flow as quickly as possible. This helped recover the spent acid, which can cause severe damage if it remains in the formation for an extended period of time.

After the CoilFLATE packer was retrieved, a visual inspection of the outer element revealed no indentations or damage to the metal slats or rubber seal from perforations or casing collars, which verified that the packer had been set in casing between the perforated zones.

The proposed workover required only a single trip into the well, and the production tubing did not have to be retrieved. Depth correlation, acidizing and initiating production were performed on the same run as setting the packer, saving two runs. After the stimulation treatment, oil production more than tripled from 38 m³/d [239 bbl/d] to 120 m³/d [755 bbl/d] (left).

For more than one year after the treatment, production remained at the same improved level. The use of the inflatable-anchoring packer and wireless CCL tool curtailed the conventional rig operation that pulled the production tubing prior to any selective stimulation treatment. This workover operation was the beginning of a planned campaign for treating additional wells in the same field that had similar completions and required stimulation.

Field experience using a 2 ¾-in. OD CoilFLATE inflatable-anchoring packer proved that zones in wells with multiple completion intervals can be reliably isolated and stimulated using coiled tubing. Fast turnaround times and accurate fluid placement allow production enhancement in wells that previously could not be treated satisfactorily or economically with other intervention techniques and methods.


\[\text{Coiled tubing stimulation results in the Hassi-Messaoud field, Algeria. Production from Well MD 264 increased more than threefold from 38 m³/d [239 bbl/d] to 120 m³/d [755 bbl/d] after pumping a hydrofluoric [HF] organic acid stimulation treatment through coiled tubing using an inflatable-anchoring packer to isolate the lower target interval from an upper interval, which had previously been hydraulically fractured.}\]
Selective zonal isolation and treatment of individual intervals under extreme well conditions provide new options and alternatives for well construction and reservoir evaluation, including rig-based or rigless operations, such as well testing of individual zones, pressure and temperature monitoring, and pressure-decline testing. Combining tools and multiple concentric operations also has helped improve the overall efficiency of remedial workovers and well recompletions across an entire field in the Middle East.

Single Rig-Up, Multiple Operations

Petroleum Development Oman (PDO) and Schlumberger collaborated on a novel methodology to facilitate well recompletions in a mature northern Oman field. This new technique combined a series of operations into a single intervention, eliminating multiple trips to a wellsite and the need to mobilize both coiled tubing units and conventional workover rigs above).²

Most of the wells in this field produce from the Shuaiba carbonate formation, and are completed with cemented and perforated 4-1/2-in. OD horizontal liners. Water production currently exceeds 90% of the total field output, so these wells are produced by artificial lift—gas lift or electrical submersible pump. High drawdown pressures cause scale deposition, which necessitates wellbore cleanouts prior to performing workover operations.

Well interventions also include acquisition of a pulsed-neutron log to measure fluid saturations and prioritize potential completion intervals according to oil content and potential productivity. These evaluations are followed by perforation and stimulation of selected intervals.

Initially, PDO performed these interventions using two coiled tubing units, one with and one without an internal wireline. The operator also performed jobs with two coiled tubing units and a workover rig. Both methods, however, were costly.

Operations without a workover rig required at least four separate coiled tubing runs. During the first run, PDO used conventional coiled tubing to clean out the wellbore liners. On the second run, the company used coiled tubing with an internal wireline to acquire a pulsed-neutron log.

On subsequent runs PDO perforated new intervals using conventional coiled tubing with a hydraulic firing head and stimulated each new completion interval during a series of wellbore entries that involved running and retrieving perforating guns under pressure.

From wellbore cleanout and pulsed-neutron logging through perforating and stimulation, these operations required about 10 days on location and at least three months to complete, even when the intervention proceeded without significant problems.

Compared with these multiple coiled tubing interventions, operations involving two interventions with coiled tubing and one intervention with a workover rig required more time on location, about 12 days, but less total time, about two months. However, costs were higher. During the first operation, PDO used conventional coiled tubing to clean out the wellbore. The second operation involved running a pulsed-neutron log using coiled tubing with an internal wireline.

Perforating and stimulation were performed during operations with a workover rig. Cleanout and logging operations were not performed with the workover rig because pulsed-neutron logs needed to be acquired under live-well, or flowing, conditions.

This approach avoided flushing of the near-wellbore region by wellbore fluids under static or overbalanced pressure conditions, which can create false saturation readings in perforated high-permeability and naturally fractured zones. PDO also observed that stimulation results with a polymer-base diverting system were not optimal in this naturally fractured formation, even when combined with mechanical diversion systems, such as an isolation straddle packer.

PDO evaluated alternative methods of acquiring pulsed-neutron logs and quickly using this information to identify production optimization and recompletion opportunities. Various methods were considered to maximize well productivity and reduce costs, including a nondamaging, surfactant-base, self-diverting acid system.²
PDO and Schlumberger proposed an innovative solution for these gas lift wells: a single rig-up intervention with coiled tubing. During one continuous operation, a single coiled tubing unit would be used for wellbore cleanouts, logging, perforating and stimulation treatments. Schlumberger developed a specialized string of coiled tubing and modular bottomhole assemblies for performing these operations and production log spinner surveys to evaluate if water shutoff is required (below right).

This coiled tubing string includes a modified wireline cable with an armored outer sheath, or jacket, to provide stability under unstable load conditions and sudden compressive forces inside the coiled tubing. A special plastic coating protects the wireline from corrosive treatment fluids that could degrade the mechanical or electrical performance of the cable.

The system is compatible with the Secure detonator, which requires more than 200 volts to activate and initiate the firing of perforating charges, is safe against stray or static voltage, and does not require radio silence on locations. Underbalanced perforating also can be performed during these interventions by activating the gas lift system or by displacing the wellbore with lighter fluids.

PDO first applied this system in Well A to perforate and stimulate in a single operation with the same coiled tubing unit. This well produced 430 m³/d [151 bbl/d] of oil output. The well produced 523 m³/d [3,290 bbl/d] of total fluid with 25 m³/d [157 bbl/d] of oil.

PDO evaluated objectives, procedures, risks and results on these first two wells to optimize operational efficiency, and to further reduce the time requirements and costs of these operations. As a result, PDO eliminated the dummy run on subsequent jobs. This integrated well-intervention method required about six days on location over a 15-day period, or less than half a month. Compared with 10 to 12 total days over two to three months for previous multiple-entry methods, this saved PDO US$ 60,000 to US$100,000 per well (next page, top).

PDO applied this new remedial technique to acquire fluid saturations and quickly identify recompletion opportunities on 10 wells, resulting in less deferred production and early returns on worker investments. Using this approach to perform various combinations of remedial operations, PDO exceeded production targets for this field and saved more than US$ 1 million in 2004. PDO is currently evaluating the application of this technique in other areas.

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![Single rig-up well interventions with coiled tubing. PDO and Schlumberger developed a specialized string of coiled tubing and modular tool assemblies specifically to perform wellbore cleanouts, well logging, perforating and stimulation operations. The customized logging and perforating head requires simultaneous pumping of fluid at a predetermined rate and overpull to disconnect the head. This dual-release mechanism avoids an unintentional disconnect from the head.](image-url)
Improving the profitability of concentric operations. Multiple-entry remedial operations without a workover rig required that PDO perform at least four separate coiled tubing runs, requiring about 10 days on location over three months (red). Well interventions involving two coiled tubing operations and one operation with a workover rig required less total time, about two months, but 12 total days on location with costs that were higher (blue). The integrated single rig-up method using a specialized string of coiled tubing and one coiled tubing unit required only about six days on location over a 15-day period (black).

Continuous Tubing, Continuous Improvement

The reliability of coiled tubing equipment and operational practices continues to improve. From the most basic applications to the most complicated, advances in coiled tubing tools, techniques and concentric operations ensure safer and more efficient day-to-day operations. As a result, coiled tubing technology has become firmly established in many areas of oil and gas activity that cannot be adequately addressed using conventional well-intervention operations, techniques and services.

The modular nature of coiled tubing systems, rigless operations, quicker well-turnaround times and accurate selective placement of fluids or stimulation treatments are helping producing companies optimize well performance. Increasingly, operators are reevaluating fields and individual wellbores for remedial intervention or recompletion operations using coiled tubing, including many wells that previously were considered too risky even for conventional operations (below left).

However, not all concentric well interventions require new technology or mandate that existing coiled tubing equipment and techniques be pushed beyond their current limits. Operators and providers of coiled tubing services also are collaborating to develop innovative tool combinations and integrated systems, operational best practices and new approaches that can improve well productivity and increase reserve recovery in new and mature fields alike. By building on these cooperative efforts, Schlumberger is improving and expanding concentric services through ongoing development and optimization of coiled tubing equipment, procedures and techniques.

Improvements in materials and manufacturing, advances in design software, and real-time monitoring and control have significantly reduced the frequency of coiled tubing failures and increased the success of through-tubing operations. There are still some operating companies that have not forgotten about the limitations and problems that were associated with early coiled tubing strings and equipment. However, through knowledge sharing and better communication, more oilfield companies are comfortable performing concentric well interventions using coiled tubing. —MET

Expanding the application of coiled tubing reentry drilling. Producing companies are becoming more confident in conducting remedial interventions or recompletions through existing production tubulars. During December 2004, BP Sharjah Oil Company reentered a well in the Sajaa field for a second time and drilled four additional laterals using underbalanced techniques and coiled tubing. BP initially had reentered this well with coiled tubing drilling three laterals in August 2003.