Shining a Light on Coiled Tubing

A cultural shift is taking place in coiled tubing operations. No longer do CT crews rely solely on surface measurements to infer downhole conditions. Using fiber optics and downhole sensors, operators can monitor critical processes, fine-tune job parameters and adapt to changing conditions as the job progresses.

Any maintenance or remedial workover is a major event in the life of a well. In many cases, a workover requires the removal and replacement of the production tubing string after a workover rig has been placed on location and the well has been killed. To preclude the production problems and expense associated with these activities, many operators turn to coiled tubing (CT) technology to permit remedial work on live wells. This technology permits tools and materials to be deployed through existing production tubing or casing while the well continues to produce.

Coiled tubing fulfills three key needs that are vital for performing remedial work on live wells. First, any such operation requires a means of providing a dynamic seal between the formation pressure and the surface. Next, a continuous conduit that can be run into a well to allow fluid conveyance is needed. And finally, there must be a way to both run this conduit into the well and retrieve it under pressure.

Benefits of the CT approach include rapid mobilization and rig-up, fewer personnel, small environmental footprint and reductions in time associated with pipe handling while tripping in and out of the hole. More importantly, the capability for continuous circulation allows an operator to avoid the risk of formation damage inherent in killing a well. These advantages yield significant cost savings for CT methods when compared with conventional workover operations.

Coiled tubing operations, however, are not without their problems. Since the technology’s inception, CT crews have had to infer from surface measurements what was happening downhole. Well service operations, by their very nature, unsettle the downhole environment of any well. Mechanical events, chemical processes and the movements of fluids inevitably cause downhole perturbations that result in pressure or temperature changes. Except in rare instances where costly permanent completions have been installed, the only options for monitoring downhole disturbances have been through surface pressure and rate measurements.

These measurements may be severely hampered or attenuated by interference that occurs between the initial disturbance event and subsequent events. The biggest limitation, however, is that surface measurements do not reflect any correlation between the disturbance and the depth at which it occurred. With no direct measure of bottomhole parameters, the operator could only deduce answers to serious concerns pertaining to the fluid level in a well, or the depth of a packer when it inflated or wellbore pressures prior to perforating.

These issues are being addressed through the use of optical fibers. In one application, a new downhole monitoring system uses fiber-optic strands inside a CT string to measure temperature along the length of the wellbore while providing telemetry between the surface and...
downhole tools and sensors. Real-time pressure and temperature data, along with depth correlations provided by the ACTive in-well live performance system, enable CT crews and operators to measure downhole conditions and monitor events as they unfold.

The downhole data provide quantitative feedback on a well’s response to ongoing treatments. And because these downhole measurements can be tied to depth, it is possible to correlate them to existing petrophysical measurements. The CT data can be further correlated to surface indicators and data from offset wells to verify treatment performance. Onsite interpretation software helps operators evaluate subtle indicators that may alert them to deviations from the job design. They can then respond immediately to changing downhole conditions by adjusting parameters to optimize treatment while the CT string is still in the wellbore and the treatment is underway.

This article briefly reviews CT systems and describes general applications of this technology. Case studies from Malaysia, Canada and Saudi Arabia show how advances in CT measurements and telemetry are helping operators to better implement their downhole treatment programs.

**Typical CT Applications**

At the center of any CT surface operation is a coiled tubing unit (CTU) from which a continuous length of flexible steel pipe is spooled. This pipe is kept on a large storage reel during transport to the wellsite. As it is spooled off the storage reel, it passes through a gooseneck and is straightened just before it enters the borehole. At the end of the operation, the flexible pipe is pulled out of the well and spooled back onto the reel (above left).

On the hub of the storage reel, a high-pressure swivel joint enables pumping of treatment fluids through the tubing, even while the reel is rotating. An injector head pulls the CT string off the spool and runs it into the wellbore. From the CTU cabin, the CT operator controls the hydraulically driven injector head to regulate the movement and depth of the CT string. A stripper assembly beneath the injector head provides a dynamic seal around the tubing string, which is key for running the CT string in and out of live wells. A blowout preventer (BOP) assembly between the stripper and wellhead supplies secondary and contingency pressure-control functions. The operation is monitored and coordinated from the CTU control cabin (left).
Coiled tubing commonly has a diameter of 1 to 2 in. and may range in length from 2,000 to more than 20,000 ft [610 to 6,100 m], depending on spool size. Continuous lengths of tubing obviate connecting one joint of pipe to the next while tripping into the well. With no need to make or break connections between joints, CT permits continuous circulation while running in or out of the hole. Continuously circulating during well treatment enhances flow control, and this capability is a primary reason for using CT in live-well interventions.

Completion or remedial operations increasingly employ CT to improve well performance through perforating, stimulation treatments or removal of pipe scale and debris. The CT string sometimes serves as a production string in shallow gas wells and has even been utilized in certain drilling and cementing operations. Its strength and rigidity, combined with the capability to circulate treatment fluids, offer distinct advantages over wireline tools during workover operations.

Coiled tubing jobs can be grouped into three broad categories: conveyance or placement of tools, conveyance or placement of fluids, and completion operations.

**Tool conveyance**—Its strength and rigidity enable CT to push or pull equipment and tools through highly deviated or horizontal wellbores and restrictions, or even push obstructions beyond the zone of interest. Coiled tubing has proved capable of conveying tools downhole in a wide range of assignments.

In zonal isolation applications, the operator must set plugs or packers to mechanically isolate a particular interval within a wellbore. Operators frequently employ coiled tubing to convey and place bridge plugs and mechanical, hydraulic or inflatable packers.

Cleanout operations require a means of removing scale buildup or fill material that can threaten production by restricting flow through tubing or casing. One approach is to run CT into the well with a removal tool to wash away the material (above right). One example, the Blaster tool, is a rotating high-pressure jetting assembly that forcefully sprays solvents, acids or abrasive fluids to remove scale or clean downhole screens and perforations.

Coiled tubing technology also extends to well perforating operations. Shooting holes through tubing and casing to produce a well is generally achieved by downhole explosives deployed in special perforation guns. In many cases, perforating guns are run into a well on wireline. However, because wireline tools are dependent on gravity to reach the target zone, this approach may not be possible in horizontal or highly deviated wells. And formation pressure can work against wireline tools in underbalanced wells, pushing the guns uphole and kinking the cable or even sticking the guns.

For these wells, the guns can be conveyed downhole at the end of conventional jointed tubing or coiled tubing. Either of these is stronger and more rigid than wireline, providing greater load capacity for the tubing, which translates into substantially longer gun strings and higher-angle deployments. Compared with jointed tubing, the CT option may offer advantages in speed when it comes to tripping in and out of the hole.

**Fluid conveyance**—The capacity for circulating or injecting fluids makes CT especially suited for production kickoff, cleanout, cementing and stimulation applications.

Coiled tubing can play an important role in initiating production in a well. When drilling or workover fluids exert hydrostatic pressures that exceed formation pressure, reservoir fluids are prevented from entering the wellbore. Pumping nitrogen through the CT string and into the fluid column is a common method for kicking off production by lowering hydrostatic pressure within the wellbore (below).

After the CT string is run to depth, nitrogen gas is pumped through the string and into the fluid column in the well. Nitrogen reduces the density of the hydrostatic column. Once the hydrostatic pressure of the fluid column drops below reservoir pressure, the well can begin to flow. In some cases, the same effect can be gained by circulating a light liquid, such as diesel, instead of nitrogen gas.

---


---

Winter 2008/2009

---
The most common application for CT is the cleanout and removal of sand or debris that fills a wellbore. Fill material can seriously impede production by reducing the flow of oil or gas. It can also block the passage of slickline or wireline tools during well operations or prevent downhole sleeves and valves from opening or closing. Common sources of fill are sand or fine material produced from the reservoir, proppant materials used during hydraulic fracturing operations, organic scale and debris from workovers.

Fill removal typically involves circulating a cleanout fluid, such as water, brine or diesel, through a jet nozzle run on the end of the CT. As the fluids are circulated, they carry the debris to surface through the annulus between the CT string and the completion tubing. Sometimes, an acid or solvent is pumped to chemically break down the fill before it is circulated out of the wellbore. Gelled fluids may also be employed to provide greater solids-carrying capacity than water or diesel. The viscosity of gelled fluids slows the fall of particles, making these fluids highly effective in vertical and slightly deviated wells. In some cases, adding nitrogen increases a fluid's capacity to lift solids.

Operators often select coiled tubing as a conduit for pumping cement downhole. It can be used in cement squeezes to seal perforations or casing leaks, for primary or secondary zonal isolation and to set cement plugs for kickoff or abandonment operations. The squeeze technique plugs casing leaks or existing perforations by pumping specially designed cement slurry under pressure into these openings. A properly designed squeeze job causes the cement to fill the openings between the formation and the casing, forming a seal. Setting a cement plug involves circulating the cement slurry into position using CT and then withdrawing the CT string to a point above the top of cement. A slight squeeze pressure is applied if necessary, the cement is displaced by a tail slurry, and then the CT is pulled out of the hole.

Compared to a standard workover rig, the CT approach to cementing offers a range of advantages:

- There is no need to pull completion equipment.
- The operation can be conducted without killing the well.
- The cement can be placed accurately, thus reducing contamination of the slurry.

Treatment programs often use CT to convey stimulation fluids that boost production by restoring or improving the permeability of a reservoir. In a matrix treatment, fluids are pumped into a reservoir at a pressure below the formation fracture threshold (see “Options for High-Temperature Well Stimulation,” page 52). This technique pushes the fluids through the open pore spaces without initiating a fracture.

**Completion operations—CT** can facilitate the installation of production tubing and associated completion equipment. In certain wells, a string or section of CT remains in the borehole as a permanent part of the completion. CT completions can provide a low-cost approach for prolonging the life of old wells. Typical installations include velocity strings, tubing patches and through-tubing gravel packs (GPs).

For example, in some wells operators choose to permanently install CT as a velocity string inside existing production tubing. This approach is used when a reduction in the gas-to-liquid ratio of produced fluids or a decrease in bottomhole pressure causes a decline in production. A decrease in fluid flow velocity results as gas content declines, and the ensuing increase in fluid slippage causes the well to load up. The velocity string reduces the cross-sectional flow area of the tubular, thus yielding higher flow velocity for a given production rate and allowing fluids to be carried out of well.

Coiled tubing may serve both as a conveyance and a medium for patching production tubulars. A CT tubing patch can be positioned in a completion to cover mechanical damage or erosion in tubing, to permanently shut off a sliding sleeve, or to isolate perforations. Packers set at the top and bottom of the patch hold it in position and provide the seal between the existing completion and CT string.

Coiled tubing is often used in completion programs to convey tools, fluids and materials. Frequently, wells drilled in unconsolidated sands require the wire-mesh screen of a GP to prevent sand production. Common GP installations involve a washdown procedure.

First, the CT string is run to the GP depth, then gravel is pumped through the coiled tubing. The CT string is then retrieved to surface and a GP screen assembly is attached (left). As the cylindrical screen is run to the top of the gravel, fluid is pumped through the CT to agitate the gravel and allow the screen to settle into place across from the perforations. The CT string is then retrieved to surface. The GP keeps the sand in place while allowing formation fluids to flow. Should sanding begin later in the life of a non-GP well, coiled tubing offers a means of installing a through-tubing GP completion, in which GP screens are installed through the existing production tubing to maintain the original completion hardware.

### ACTive Sensors and Telemetry

The success of fill cleansouts, matrix stimulations, cementing jobs and other CT applications is closely linked with the ability to model and evaluate the behavior of downhole parameters such as temperature and pressure. In other applications such as perforating operations or installation of packers, tubing patches or whipstocks, the ability to accurately control depth is absolutely necessary. However, CT crews and operators often depend on indirect surface indicators to infer these critical parameters.

For conventional CT jobs, downhole pressure is often estimated from surface readings of pressure at the pump or wellhead. However, subtle pressure changes can be attenuated through thousands of feet of wellbore fluid before reaching surface. Thus, surface indicators may sometimes be misleading.
Tool depth is another critical parameter that may be subject to error or misinterpretation. For instance, accurate placement of gun strings is essential to the success of any perforating job. Poor depth control could mean a missed target or poor contact with the hydrocarbon interval or—even worse—perforating into a water zone.

In the past, a dedicated tie-in run was required for depth control. The CT was run in the hole with a memory gamma ray and casing collar locator (GR-CCL) tool to identify a known reference point in the well. Typical reference points included the bottom of the well, a known restriction, a distinctive piece of completion equipment or a short length of pipe called a pup joint. Reference points such as TD or a known restriction were found by tagging, or gingerly setting down on them. Others, such as pup joints or completion intervals, were located by the GR-CCL tool. Upon reaching the reference point, a mark was placed on the coiled tubing at surface to flag the amount of tubing that had been spooled off the reel. The CT GR-CCL was then pulled out of the hole, and perforating guns were installed.

However, other factors enter into the depth-tie-in process: the length of the interval from the downhole correlation point to the pay zone must be considered, along with a host of new details. Between the memory run and the perforating run, a change in tools will be accompanied by a significant change in bottomhole assembly (BHA) dimensions and weights, fluids, friction, debris and coiled tubing deformation. Any one or combination of factors could alter the placement of the downhole measure point with regard to the surface reference flag. Tubing-depth errors as high as 0.3% were not uncommon.

The industry is quite aware of the potential for trouble caused by reliance on surface indicators. The range of problems is wide and varied:

- packers and plugs that are set off depth as a result of poor depth control
- perforating guns that are detonated off depth because of poor depth control
- guns that fail to fire owing to pressure discrepancies—discovered only after coiled tubing has been retrieved to surface
- wells that fail to perform as expected as a result of insufficient underbalance prior to perforating.

To address such issues, a special BHA was developed along with an advanced fiber-optic telemetry system and a surface control system for assessing downhole job performance. The ACTive monitoring system incorporates sensors inside the BHA to measure temperature, annulus pressure and CT pressure (right). Depth control is handled by a fully configurable casing collar locator, also carried in the BHA. The CCL is sensitive enough to detect collars at any logging speed and is capable of detecting flush-joint connections at logging speeds of 15 ft/min [4.6 m/min]. This sensitivity has also helped operators find other anomalies, such as perforations and casing defects.

Designated as the PTC (pressure, temperature, CCL), this BHA and associated telemetry system give operators access to fundamental information that might only be seen in surface measurements many seconds later—or not at all. Measurements made downhole, at the point of application, help CT crews more accurately control depth and respond to parameters as they change during the course of a treatment. The PTC assembly is made up beneath the CT head at the terminus of the CT string. It can be run with other CT tools such as a perforating gun, multilateral locator tool, inflatable packer and jetting tool, and it is designed to withstand high tensile loads, torque and pressure.

This tool has two distinct sections: the CT head, which provides a CT connector while housing the termination for the optical fiber, and a power supply for electronic components. The 2%-in. [5.4-cm] OD BHA comes with a built-in check valve. The minimum flow-through restriction is 0.688 in. [1.7 cm], which allows ball-operated tools to be run below the fiber-optic sub.

A rugged high-bandwidth fiber-optic telemetry system is placed inside the CT string to convey PTC measurements to surface. Optical fiber offers a number of advantages over other hard-wired transmission media. In contrast to electric wireline, glass fibers are used to carry signals in the form of light pulses, resulting in faster transmissions and immunity to electromagnetic interference. Certain wavelengths of these light pulses are sensitive to changes in temperature, and this characteristic is exploited to create an intrinsic sensor that measures temperatures along the length of the fiber (see “Downhole Temperatures from Optical Fiber,” page 34).

The ACTive configuration uses four optical fibers: Two strands are dedicated to the PTC, one is used for measuring temperature, and one strand is set aside as a spare. These strands are enclosed in a protective and flexible INCONEL steel carrier. The carrier and fibers are run through the CT reel to the head of the tool at the end of the CT string. The fiber-optic carrier, with an outer diameter of just 0.071 in. [1.8 mm], has a negligible impact on the CT internal cross section and so does not affect pumping rates. It is very lightweight, weighing nearly one-twentieth of an equivalent length of electric...
monocable wireline. The nickel-chromium alloy of the metal carrier has been tested extensively and has withstood temperatures up to 300°F [149°C] and corrosive acid treatments or harsh bottomhole conditions common to nitrogen kickoff or fill-cleanout jobs. This self-contained fiber-optic system imposes no additional footprint on standard CT packages.

A two-way communication module, mounted behind a pressure bulkhead on the CT reel, receives data from the PTC sensors via the fiber-optic system. The communication module also transmits commands downhole through the tool's fiber-optic bundle. At the surface, a communication bridge moves data securely and wirelessly between the communication module and a router in the CTU control cabin. A computer in the control cabin displays and monitors downhole job parameters, and can transmit commands back to the communication module and then down to the tool (above and next page). Using the ACTive BHA, telemetry and control system, the operator can monitor annular pressure to confirm efficient cleanouts, measure inflation- and differential-pressure across a packer, or confirm in real time that perforating guns have detonated successfully.

These downhole measurement capabilities have been put to the test around the world, across a wide range of applications.

**ACTive Perforating in Malaysia**

Talisman Malaysia Ltd. (TML) operates more than 130 wells in the South China Sea, where the company has gained extensive experience in perforating using CT conveyance. To carry out a CT perforation campaign, TML called for the ACTive system to ensure that perforations were shot on depth. TML set a maximum underbalance that would not exceed a safe formation drawdown to avoid the risk of collapsing the perforation tunnels. The company also anticipated a savings in rig time achieved by avoiding depth-tie-in runs.

---

Talisman’s experience, along with perforating records and production analysis, indicated that the higher the underbalance, the more effective the removal of perforation damage. However, in neighboring fields, guns had sanded in as a result of excessive drawdown. After evaluating core and log data, the TML reservoir group determined that a 1,000-psi [6.9-MPa] initial underbalance would be sufficient to remove perforation damage while avoiding failure of the perforation tunnels and fluid invasion beyond the new perforations. The group chose deep-penetrating charges to bypass drilling damage and increase effective wellbore radius.

TML planned to perforate several intervals that were just 2 to 3 m [7 to 10 ft] in length. A high degree of depth accuracy and a means to confirm gun detonation were therefore required. TML also wanted flexibility to use the CT for other applications such as fill cleanout, if necessary. Size and weight were also considerations because the job was to be performed without a rig; crane capacity on most of the platforms was only about 16 metric tons and deck space was limited.

TML’s plan called for displacing wellbore fluid with nitrogen to achieve the required underbalance of 1,000 psi in this 3,200-psi [22-MPa] reservoir. As nitrogen pumping progressed, ACTive real-time bottomhole pressure measurements prompted the operator to displace an additional 50 bbl [5.8 m³] of fluid from the well to achieve the desired underbalance. Real-time measurements following this additional displacement confirmed a bottomhole pressure of 1,000 psi.

^ Downhole pressure readings. This window is used to monitor downhole pressure conditions as they occur at different depths within a wellbore. ACTive downhole pressure data can be combined with user input regarding fluid types to obtain feedback on downhole pressure conditions. Although this display shows four zones, the operator can actually monitor up to six different depths at a time. The background of each dial changes color to represent real-time pressure conditions seen at a particular zone. While the dial presents a snapshot in time, a bar graph below each dial displays pressure conditions during the entire job. These readings can be easily referenced in real time during the job or can be saved for postjob analysis.
2,200 psi [15.2 MPa], thus signaling that 1,000-psi underbalance had been reached in accordance with the perforating design.

The CCL tool on the ACTive BHA helped to precisely position the guns at the zone to be perforated. During descent, the CCL detected short pup joints installed above the perforation zone. During the first run, a 10-m [33-ft] gun string was used to perforate a pay interval. With the guns on depth, nitrogen pulses were sent downhole via the annulus to the eFire-CT electronic firing head system. Upon receiving the correct sequence of pulses, the eFire-CT system detonated the guns. In the control cabin, the operator saw positive confirmation that the guns had fired as programmed: The ACTive sensor recorded an instantaneous increase in bottomhole pressure to 3,700 psi [25.5 MPa], accompanied by an increase in bottomhole temperature (left).

The coiled tubing was then retrieved to surface and the well was flowed to production. Following the perforation of a second, adjacent zone, production was established at 70 MMcf/d [1.98 million m³/d].

Openhole Stimulation in Canada
An operator in western Canada faced multiple challenges while planning matrix stimulation of a multilateral well in a mature gas field. This multilateral well consisted of openhole completions in two branches drilled in a naturally fractured dolomite formation. Along with methane, it produced 21% H₂S and 5% CO₂. Successful stimulation would hinge on three important factors:

- ability of the conveyance tools to enter each branch of the well
- proper functioning of the tools in a subhydrostatic environment
- effectiveness of the stimulation fluid in treating the formation.

The subhydrostatic condition resulting from depletion of this mature reservoir limited its ability to support a full column of fluid, which is normally required when using downhole tools that depend on pressure-pulse telemetry. The ACTive matrix stimulation service—with its fiber-optic telemetry, CCL depth control, precise fluid-conveyance capabilities and downhole temperature and pressure measurements—was an ideal alternative. To guide its entry into the intended branch of the well, a multilateral reentry tool was attached to the crossover sub beneath the ACTive BHA.

The Discovery MLT multilateral tool consists of an orienting tool and a controllable bent sub. From the surface, the CT engineer can orient the tool azimuthally while controlling the angle of the bent sub to identify the window to each lateral in a multilateral well. Downhole pressure readings allow the engineer to confirm successful entry into the selected leg. After the lateral branch designated for stimulation was entered, depth correlation using the CCL aided in positioning the BHA for optimal stimulation.
Pretreatment distributed temperature sensor (DTS) data showed CT crews where to spot the stimulation acid and the diverting acid, while real-time bottomhole pressure readings provided feedback during the treatment. Once the initial treatment had been pumped, downhole temperature readings identified enhanced fluid-injection points and other zones that could be opened up further. Based on analysis of these downhole readings, the operator fine-tuned the divert and acidizing program and revised the pump schedule for the next stage. The changes allowed temporary diversion of fluid from the initially stimulated zones and provided better overall treatment of each branch of the multilateral (previous page, bottom left). A subsequent DTS survey confirmed that the treatment had successfully diverted the acid to stimulate the remaining targeted zones.

Reducing Water Cut in Saudi Arabia

In Saudi Arabia, the ACTive system was used to revive oil production in a horizontal well with a 60% water cut. The new well, an openhole completion, had been producing oil intermittently from a carbonate reservoir. Most of the water was produced from the toe of the well.

Saudi Aramco appreciated the complexity of water shutoff operations in this horizontal well. A lack of information about depth, bottomhole temperature and pressure could affect the reliability of high-expansion bridge plugs, cement-plug formulation and placement of isolation devices to shut off the water-producing zone. Saudi Aramco selected ACTive services to provide zonal isolation and reduce water cut without using a workover rig.

The operation deployed a through-tubing inflatable packer on CT, along with a cement plug, to isolate the water-producing zone from the rest of the horizontal wellbore. PTC temperature and pressure measurements obtained during the first run in the hole aided in formulation of a customized cement slurry program. The packer was set in place during the second run in the hole. Real-time readings from the PTC casing collar locator were used to confirm the bottom of casing in this openhole completion, and the packer setting depth was correlated from this point. After the packer was placed at the oil/water interface, a ball was dropped through the ACTive BHA to initiate setting and expansion of the packer. Specially formulated cement slurry was pumped on top of the packer during the third CT run (left). To restart production, nitrogen pumped in the hole displaced the kill fluids while CT crews monitored downhole pressures in real time.

Using the ACTive isolation service, Saudi Aramco was able to cut the operation time in half. Water cut decreased from 3,000 bbl/d [477 m³/d] to 1,500 bbl/d [239 m³/d], and oil production increased by 1,000 bbl/d [150 m³/d].

The Future Is Now

New measurement capabilities for fiber optics are the focus of several investigations and may come to enhance the array of tools available for CT applications. These measurements will provide advances in production logging capabilities and enable monitoring of operational parameters for improved BHA performance and longevity. Field experience is already leading to more sophisticated workflows and intuitive interpretation software to make the most of the downhole measurements.

Operators are realizing benefits in increased safety and efficiency obtained through monitoring downhole conditions. Further increases in safety and efficiency will come as more operators monitor these jobs from their own desks, maintaining their office schedules while reducing their exposure to travel and wellsite risk. This vision is already a reality in some areas. In Alaska, some BP staff monitor job progress by taking advantage of secure real-time data transmissions from the wellsite. A standard Web browser and Internet port connect experts from the BP Anchorage office to approximately 80% of the BP wellsites around Prudhoe Bay. Transmissions to the BP iCenter networked collaborative environment enable Anchorage-based engineers to view data and discuss options with rig personnel.

The popularity, and hence the capabilities, of fiber-optic coiled tubing will continue to grow as this technology expands into a broader range of applications.

— MV