ICoTA

International Coiled Tubing Association

presents

An Introduction to Coiled Tubing

History, Applications, and Benefits

ICoTA Mission

To enhance communication, gather technical expertise and promote safety, training competency and industry accepted practices within the coiled tubing industry.

The ICoTA website contains a wealth of additional Coiled Tubing information, including technical papers, the latest meeting notices, etc.

Please visit our website at: www.ICoTA.com

What is CT?

Coiled Tubing (CT) has been defined as any continuously-milled tubular product manufactured in lengths that require spooling onto a take-up reel, during the primary milling or manufacturing process. The tube is nominally straightened prior to being inserted into the wellbore and is recoiled for spooling back onto the reel. Tubing diameter normally ranges from 0.75 in. to 4 in., and single reel tubing lengths in excess of 30,000 ft. have been commercially manufactured. Common CT steels have yield strengths ranging from 55,000 PSI to 120,000 PSI.

Key Elements of a CT Unit

The coiled tubing unit is comprised of the complete set of equipment necessary to perform standard continuous-length tubing operations in the field. The unit consists of four basic elements:

- Reel - for storage and transport of the CT
- Injector Head - to provide the surface drive force to run and retrieve the CT
- Control Cabin - from which the equipment operator monitors and controls the CT
- Power Pack - to generate hydraulic and pneumatic power required to operate the CT unit

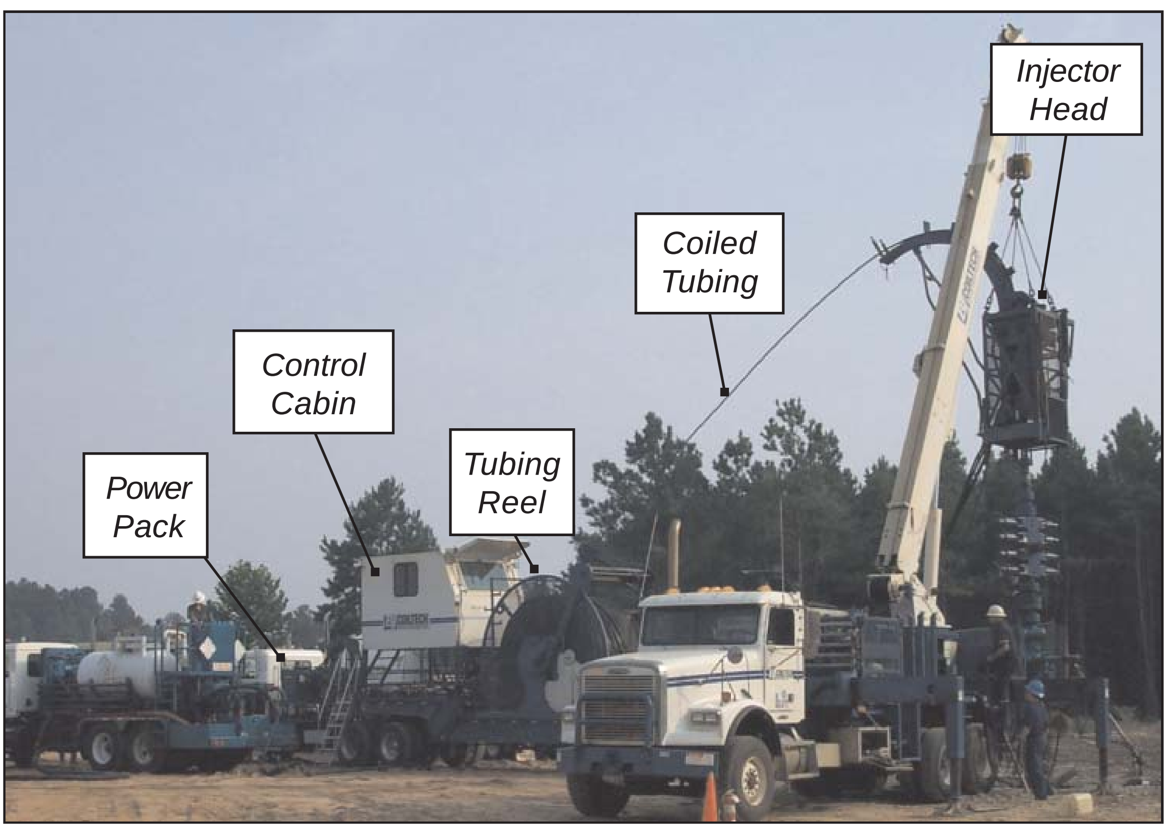

Figure 1: Trailer Mounted CT Unit and Crane

Detailed Photos of CT Unit Key Elements

Figure 2: Injector Head

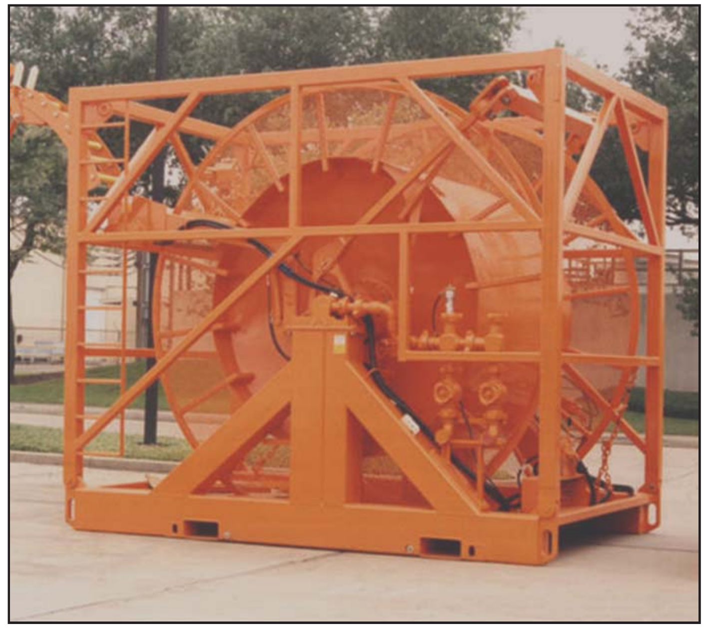

Figure 3: Reel

Figure 4: Control Cabin

Figure 5: Power Pack

Well Control Equipment

Proper well control equipment is another key component of CT operations, given that a majority of these operations are performed in the presence of surface wellhead pressure. Typical CT well control equipment consists of a BOP topped with a stripper (high pressure CT units have two strippers and additional BOP components). All components must be rated for the maximum wellhead pressure and temperature possible for the planned field operation.

The stripper (sometimes referred to as a packoff or stuffing box) provides the primary operational seal between pressurized wellbore fluids and the surface environment. It is physically located between the BOP and the injector head. The stripper provides a dynamic seal around the CT during tripping and a static seal around the CT when there is no movement. The latest style of stripper devices are designed with a side door, that permits easy access and replacement of the sealing elements, with the CT in place.

The BOP is situated beneath the stripper, and can also be used to contain wellbore pressure. A CT BOP is designed specifically for CT operations. It consists of several pairs of rams, with each ram designed to perform a specific function. The number and type of ram pairs in a BOP are determined by the BOP configuration: single, double, or quad. A quad system is commonly used in most operations.

The four BOP rams, from top to bottom and their associated functions are:

- Blind ram - seals the wellbore when the CT is out of the BOP
- Shear ram - used to cut the CT
- Slip ram - supports the CT weight hanging below it (some are bi-directional and prevent the CT from moving upward)
- Pipe ram - seals around the hanging CT

Standard CT BOPs also contain two equalizing ports, one on each side of the sealing rams. It also has a side outlet between the slip and shear rams. This outlet can be used as a safety kill line. BOPs are available in a range of sizes, and normally follow the API flange sizes.

CT Benefits

While the initial development of coiled tubing was spurred by the desire to work on live wellbores, speed and economy have emerged as key advantages for application of CT. In addition, the relatively small footprint and short rig-up time make CT even more attractive for drilling and workover applications.

Some of the key benefits associated with the use of CT technology are as follows:

- Safe and efficient live well intervention
- Rapid mobilization and rig-up
- Ability to circulate while RIH/POOH
- Reduced trip time, resulting in less production downtime
- Reduced crew/personnel requirements
- Cost may be significantly reduced

Coiled tubing can also be fitted with internal electrical conductors or hydraulic conduits, which enables downhole communication and power functions to be established between the BHA and surface. In addition, modern CT strings provide sufficient rigidity and strength to be pushed/pulled through highly deviated or horizontal wellbores. This enables successful execution of downhole operations that would be impossible to perform with conventional wireline approaches, or would be cost prohibitive if performed by jointed-pipe.

CT Field Applications

The use of CT has continued to grow beyond the typical well cleanout and acid stimulation application. This growth can be attributed to a multitude of factors, including advances in CT technology and materials as well as the increased emphasis on wellbores containing a horizontal and/or highly-deviated section.

The CT application list (below) is provided as a "thought-provoker", to illustrate additional operations where CT could be of benefit in your future field work.

Growth Applications

- CT Drilling
- Fracturing
- Subsea
- Deeper Wells
- Pipeline/Flowline

Traditional Applications

- Well Unloading
- Cleanouts
- Acidizing/Stimulation
- Velocity Strings
- Fishing
- Tool Conveyance
- Well Logging (real-time & memory)
- Setting/Retrieving Plugs

History

The development of coiled tubing as we know it today dates back to the early 1960's, and it has become an integral component of many well service and workover applications. While well service/ workover applications still account for more than 75% of CT use, technical advancements have increased the utilization of CT in both drilling and completion applications.

The ability to perform remedial work on a live well was the key driver associated with the development of CT. To accomplish this feat, three technical challenges had to be overcome:

- A continuous conduit capable of being inserted into the wellbore (CT string).
- A means of running and retrieving the CT string into or out of the wellbore while under pressure (injector head).
- A device capable of providing a dynamic seal around the tubing string (stripper or packoff device).

CT Origin

Prior to the Allied invasion in 1944, British engineers developed and produced very long, continuous pipelines for transporting fuel from England to the European Continent to supply the Allied armies. The project was named operation "PLUTO", an acronym for "Pipe Lines Under The Ocean", and involved the fabrication and laying of several pipelines across the English Channel. The successful fabrication and spooling of continuous flexible pipeline provided the foundation for additional technical developments that eventually led to the tubing strings used today by the CT industry.

In 1962, the California Oil Company and Bowen Tools developed the first fully functional CT unit, for the purpose of washing out sand bridges in wells.

Early CT Equipment

The first injector heads operated on the principle of two vertical, contra-rotating chains. This design is still used in the majority of CT units today. The stripper was a simple, annular-type sealing device that could be hydraulically activated to seal around the tubing at relatively low wellhead pressures. The tubing string used for the initial trials was fabricated by butt-welding 50 ft. sections of 1 3/8 in. OD pipe into a 15,000 ft. string and spooling it onto a reel with a 9 ft. diameter core.

Evolution of CT Equipment

Throughout the late 1960's and into the 1970's, both Bowen Tools and Brown Oil Tools continued to improve their designs to accommodate CT up to 1 in. OD. By the mid-1970's, more than 200 of the original-design CT units were in service. By the late 1970's, several new equipment manufacturing companies (Uni-Flex Inc., Otis Engineering, and Hydra Rig Inc.) also started influencing improved injector head design.

CT strings were also undergoing significant improvements during this period. Through the late 1960's, CT services were dominated by tubing sizes of 1 in. and less, and relatively short string lengths. Tubing diameter and length were limited by the tubing mechanical properties and currently available manufacturing processes.

Early CT operations suffered many failures due to the inconsistent quality of the tubing and the numerous butt welds required to produce a suitable string length. However, by the late 1960's, tubing strings were being milled in much longer lengths with fewer butt welds per string. During this time, steel properties also improved. These changes and the associated improvement in CT string reliability contributed greatly to the continued growth of the CT industry.

Today it's common for CT strings to be constructed from continuously milled tubing that can be manufactured with no butt welds. In addition, CT diameters have continued to grow to keep pace with the strength requirements associated with new market applications. It's not unusual for CT diameters of up to 2 7/8 in. to be readily available for routine use.

Figure 6: Modern CT Equipment on a Land Location

It's clear the CT industry has continued to make technical advancements that have opened new market applications for the technology. This progress has served to make CT an even more appealing solution for its early market applications.

Figure 7: Inside the Control Cabin of a Modern CT Unit

Figure 8: CT Unit Rigged Down for Highway Transport

Photos of Various Offshore CT Operating Environments

Figure 9: CT Operations from a Liftboat

Figure 10: CT Operations from a Barge

Figure 11: CT Operations on an Offshore Platform

The Business

The coiled tubing industry continues to be one of the fastest growing segments of the oilfield services sector, and for good reason. CT growth has been driven by attractive economics, continual advances in technology, and utilization of CT to perform an ever-growing list of field operations. Coiled tubing today is a global, multi billion dollar industry in the mainstream of energy extraction technology.

The potential advantages associated with CT are typically driven by the fact that a workover rig (and associated cost) is not required, the rapid CT trip speed in and out of the well, and that CT operations are designed to be performed with pressure on the well. Eliminating the requirement to kill the well can be a significant factor in the decision to utilize CT for a particular field operation, as it reduces the risk of formation damage.

Growth of the CT Service Fleet

In August 2005, slightly more than 1,060 CT units were estimated to be available on a worldwide basis. The total number of working CT units is up sharply from the roughly 850 units reported in February 2001. At present, the International market accounts for the bulk of the currently available CT fleet with more than 556 units. Canada and the U.S. are estimated to contribute additional 254 and 253 units, respectively. These figures are currently increasing as indicated by reports of new rig orders.

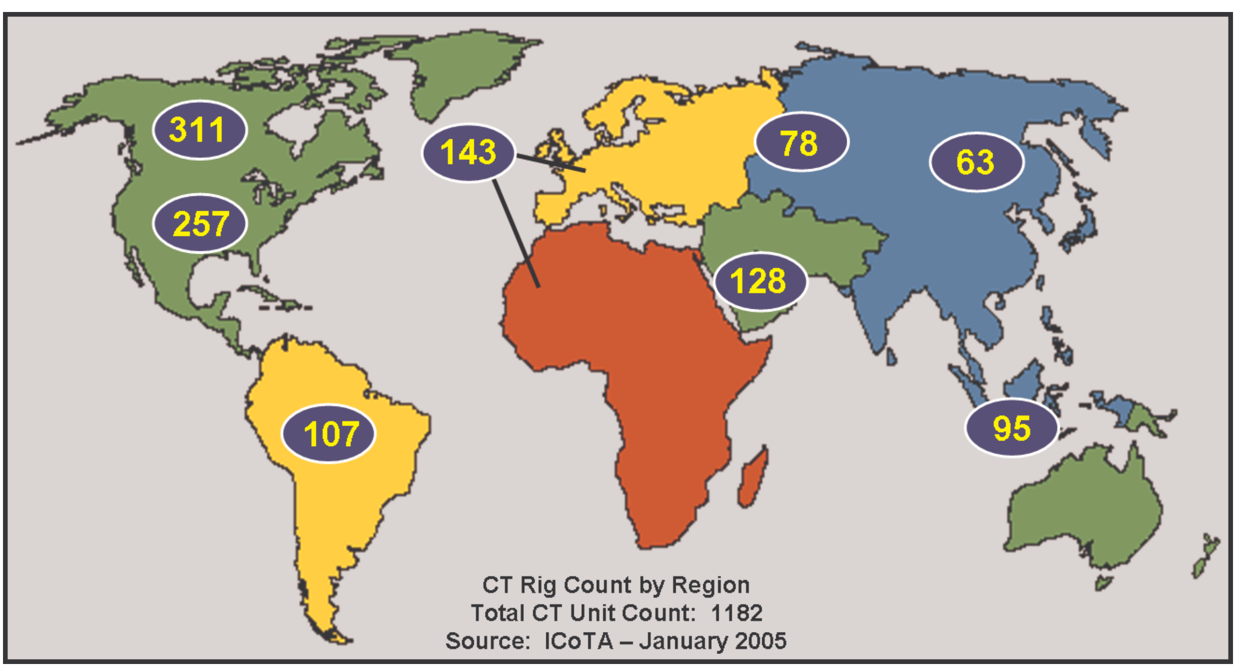

Figure 12: Global Distribution of CT Units

NEW CT MARKETS / FIELD APPLICATIONS

CT first established it's niche in the marketplace as a cost-effective well cleanout tool. In recent years, these conventional wellbore cleanouts and acid stimulation jobs accounted for more than three quarters of total CT revenue. However, CT use has continued to expand as it is adopted for use in additional field operations. Most recently, CT fracturing and drilling applications have emerged as two of the fastest growth areas. Revenue from these two CT applications has grown from almost zero 10 years ago, to approximately 15 percent in more recent times.

Figure 13: Truck Mounted 1 1/4in. CT Unit with Telescoping Hydra Lift for Fast Rigup

CT SERVICE PROVIDERS

The CT market is dominated by three large service companies, who control approximately 60% of the CT total marketplace. The market is also serviced by numerous smaller CT service providers. On a regional basis, there are typically more than 30 providers of CT in the International marketplace. Canada is serviced by more than 35 CT providers, and the U.S. by more than 25 companies.

The Tubing

The manufacture of CT involves multiple steps, and the following contains an overview of the key components involved in the manufacturing process.

- Raw Material for CT
- CT Manufacturing
- CT Mechanical Performance
- CT String Design
- CT Inspection Tools
- Repairs and Splicing
- Alternatives to Carbon Steel CT

Raw Material for CT

Virtually all CT in use today begins as large coils of low-alloy carbon-steel sheet. The coils can be up to 55 in. wide and weigh over 24 tons. The length of sheet in each coil depends upon the sheet thickness and ranges from 3,500 ft. for 0.087 in. gauge to 1,000 ft. for 0.250 in. gauge.

CT Manufacturing

At the end of 2003, two companies supplied all of the steel CT used by the petroleum industry. Quality Tubing, Inc. (QTI) and Precision Tube Technology (PTT) each have manufacturing facilities in Houston, TX. The first step in tube making is to slice flat strips from the roll of sheet steel, and this step is usually performed by a company specializing in this operation. The strip's thickness establishes the CT wall thickness and the strip's width determines the OD of the finished CT.

The steel strips are then shipped to a CT mill for the next step in the manufacturing process. The mill utilizes bias welds to splice the flat strips together to form a single continuous strip of the desired CT string length. The mechanical properties of the bias strip welds almost match the parent strip in the as-welded condition, and the profile of the weld evenly distributes stresses over a greater length of the CT. The CT mill then utilizes a series of rollers to gradually form the flat strip into a round tube. The final set of rollers forces the two edges of the strip together inside a high frequency induction welding machine that fuses the edges with a continuous longitudinal seam. This welding process does not use any filler material, but leaves behind a small bead of steel (weld flash) on both sides of the strip.

The mill removes the external bead with a scarfing tool to provide a smooth OD. The weld seam is then normalized using highly localized induction heating. Next, the weld seam is allowed to cool prior to water cooling. Full tube eddy current or weld seam ultrasonic inspection may also be performed, depending upon the mill setup. The tubing then passes through sizing rollers that reduce the tube OD slightly to maintain the specified manufacturing diameter tolerances. A full body stress relief treatment is then performed to impart the desired mechanical properties to the steel. Subsequent to the CT being wound on a shipping reel, the mill flushes any loose material from the finished CT string.

CT Mechanical Performance

The mechanical performance of CT is fundamentally different from all other tubular products used in the petroleum industry because CT is plastically deformed with normal use. Plastic deformation of material imparts fatigue on the CT string, and fatigue continues to accumulate over the life of the CT string, until such time as fatigue cracks develop, resulting in a CT string failure. [Plastic deformation can be described as deformation that remains after the load causing it is removed. Fatigue can be defined as failure under a repeated or otherwise varying load, which never reaches a level sufficient to cause failure in a single application.]

For standard CT operations, the tube is plastically deformed as the tube is straightened coming off the reel at point 1 as shown below in Figure 9 below. It is then bent at point 2 as it moves onto the guide arch, and is straightened again at point 3 as it travels to the injector and enters the wellbore. The CT string is then plastically deformed at the same three points during retrieval from the well.

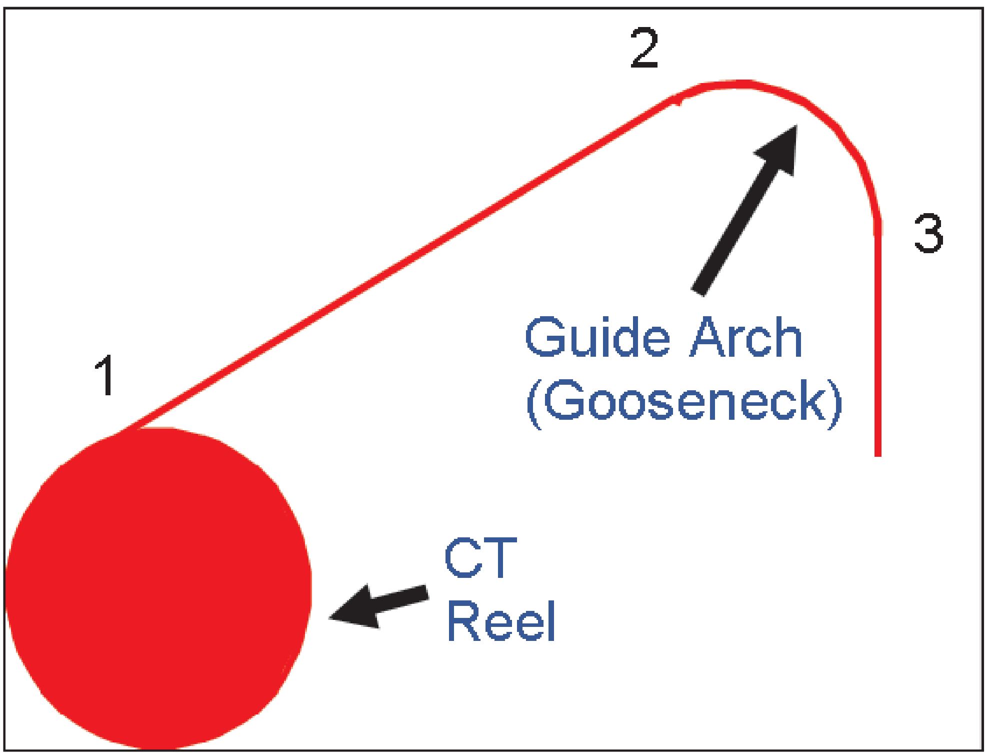

Figure 14: CT Plastic Deformation Points

CT service providers utilize sophisticated CT fatigue modeling software and field data acquisition systems to track the operating history of the CT string as it is utilized in the field. This operating history allows the CT string life to be monitored, and the string replaced prior to failure. Figure 15 contains a sample screen capture from a fatigue modeling software program, depicting the amount of CT life that has been spent during two downhole operations.

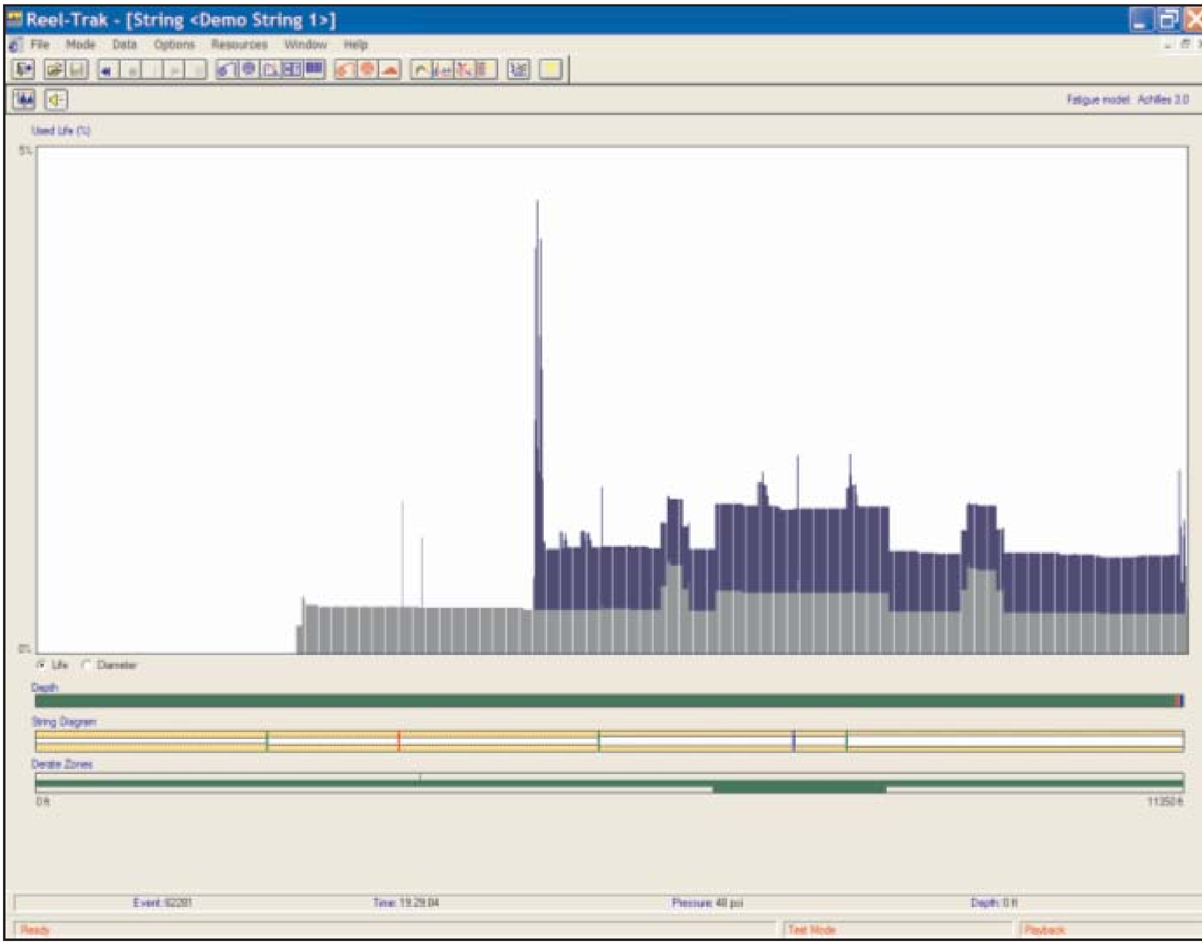

Figure 15: CT Fatigue Modeling Software

CT String Design

The length of CT on a reel varies depending on diameter. For comparison, a small reel may only be able to hold 4,000 ft. of 2 7/8 in. tubing, but may have a 15,000 ft. capacity if 1 1/2 in. tubing is spooled on it.

A properly sized CT string must have the following attributes for the planned operation:

- Enough mechanical strength to safely withstand the combination of forces imposed by the job
- Adequate stiffness to RIH to the required depth and/or push with the required force
- Light weight to reduce logistics problems and total cost
- Maximum possible working life

Optimizing the design of a CT string to simultaneously meet the criteria shown above for a given CT operation requires a sophisticated CT simulator and numerous iterations with proposed string designs. CT strings designed in this manner usually will contain multiple sections of differing wall thickness. Often called "tapered strings", the wall thickness does not necessarily taper smoothly from thick to thin (top to bottom). Instead, the wall thickness will vary according to the position in the string. However, the OD of the string will remain constant.

The simplest method of designing a CT string considers only the wall thickness necessary at a given location for the required mechanical strength and the total weight of the string. This method assumes the open-ended CT string is hanging vertically in a fluid with the buoyed weight of the tubing being the only force acting on the string. Starting at the bottom of the string and working up, the designer selects the wall thickness at the top of each section that provides sufficient tensile force at that location.

CT Inspection Tools

In addition to the practical reason for determining whether CT can safely pass through the surface equipment and be gripped properly by the injector, real-time measurements of tubing geometry are crucial for avoiding disastrous failures. To determine the suitability of a CT string for proposed operation, one must determine if:

1. The stresses in the wall of the tubing caused by pressure and axial forces will exceed the yield stress of the material, and
2. The accumulated fatigue in any segment of the string will exceed a predetermined safe limit during the course of the operation.

Tubing geometry has a direct, significant effect on both issues.

Multiple tools capable of measuring external CT geometry have been used in the CT industry. These tools measure the tubing OD on several radials at a given cross section to determine the ovality and diameter of the CT. More recently, several "full-body" CT inspection tools, with the ability to detect tubing wall flaws as well as providing tubing wall thickness and geometry measurements, have been utilized. Real-time inspection systems are being used during offshore operations to assure total integrity of the coiled tubing.

Repairs and Splicing

The only acceptable method of repairing mechanical or corrosion damage to a CT string is to physically remove the bad section of tubing and rejoin the ends with a temporary or permanent splice.

A temporary splice consists of a mechanical connection that is formed with a tube-tube connector. This type of connection is typically not used for prolonged operations during a CT job, but rather as an emergency repair to allow the CT string to be pulled out of the hole.

However, connector technology continues to evolve and there are certain situations where connectors are used, such as to connect the tool string to the end of the CT. There are three general types of connectors, including the grapple, setscrew/dimple, and roll-on connector. Connector selection is based on the particular operation to be performed, as each type incorporates unique features that make it best-suited for a given application.

Only butt welds are possible for field welding repair of CT strings, with TIG welding being the preferred method for permanent repair of CT work strings. The low heat input and the slow deposition rate of this technique make it ideal for use with CT. The CT industry has three generally accepted TIG welding techniques:

- Manually, with hand-held tools
- Semi-automatically, with manual preparation with an automatic orbital welder
- Fully-automatically, with a robotic orbital welder

All three methods can produce high quality welds. However, even the best repair weld has no more than 50% of the fatigue life of the virgin tubing.

Addressing Offshore Weight and Space Limitations

CT operations on many offshore platforms are constrained by the lifting capacity of the crane, as well as deck loading and space limitations. A loaded CT reel is typically the heaviest component of the CT system. Various solutions to address this issue have been successfully implemented in the field, including:

1. Disassembling the CT equipment into the smallest, lightest lifts possible, and reassembling the equipment on the platform.
2. Cut the CT string into sections, spool the sections onto lightweight shipping reels, lift the reels onto the platform, then reconnect the sections on the platform.
3. Use a barge or jackup with a heavy-lift crane to hoist all of the CT equipment onto the platform
4. Lift the CT unit, minus the CT string, onto the platform. Then spool the CT string onto the work reel from a loaded reel on a floating vessel.
5. Install only the CT injector on the wellhead, leaving the CT reel and other CT unit components on a barge, workboat, or jackup, positioned alongside the platform.

The first four options can be applied where crane lift capacity is the controlling factor. Option 2 has been applied successfully numerous times in the North Sea, and requires high quality CT welding services to be available. Options 3-5 require more equipment and personnel versus that of typical CT operations, with an associated increase in the cost of the CT operation. Option 3 is rarely used, due to the high cost and scarcity of floating cranes.

Extending the CT Operating Envelope - Downhole Tractors

In some applications, such as wellbores with long horizontal sections, the inherit strength of the CT may not be adequate for the intended downhole task or CT lockup may prevent the CT string from being able to reach the desired depth.

In many cases, these issues can be overcome and the CT operation can be successfully completed with the addition of a downhole tractor to the CT string. A downhole tractor can pull or push on the end of the CT string, enabling it to successfully reach the target depth and/or be able to apply the required downhole force (e.g. operate a sliding sleeve).

Tractors are deployed on the downhole end of the CT string and are powered by hydraulic motors driven by the flow of fluid through the CT. Various tractor designs provide the ability to pull or push on the downhole end of the CT string, as directed by surface computer control systems. Some tractors can supply up to 11,000 lbs. of force to pull or push the CT string, and can operate at speeds of up to 30 feet per minute.

Alternatives to Carbon Steel CT

Conventional carbon steel CT is more than adequate to meet the needs of most field operations. However, some corrosive downhole environments dictate the use of improved CT materials. QT-16Cr is a relatively new corrosion resistant alloy (CRA) that was specifically developed for long term direct exposure to wet CO_2 environments. QT-16Cr was commercially introduced in early 2003, and more than 30 tubing strings were in service a year later. Much of the early application was for permanent installations as a velocity string in environments containing wet CO_2 and saline conditions. It has been installed to depths greater than 18,000 ft.

The commercial appeal of QT-16Cr goes beyond its favorable corrosion resistance characteristics. The material has also exhibited much improved abrasion resistance (approximately 1/4th the material loss vs. a well known 45 HRC low alloy steel) as well as demonstrating superior low cycle fatigue life when compared to it's equivalent in carbon steel. This data indicates the grade may be an excellent candidate for future CT work string applications.

HS-80-CRA is another CRA material being developed for use in downhole completion application in H_2S and CO_2 environments. This product is a lean duplex material that is laser welded. Early testing indicates it has very good corrosion characteristics in H_2S and/or CO_2 environments.

Another alternative to steel for manufacturing CT is a composite made of fibers embedded in a resin matrix. The fibers, usually glass and carbon, are wound around an extruded thermoplastic tube (pressure barrier) and saturated with a resin, such as epoxy. Heat or UV radiation is used to cure the resin as the tube moves along the assembly line. Composite CT can be manufactured with a wide range of performance characteristics by changing the mix of fibers, the orientation of their windings, and the resin matrix properties. The first commercial application for composite CT was three velocity strings deployed in The Netherlands in mid-1998.

The CT mills have also produced small quantities of CT made of titanium or stainless steel for highly corrosive environments, but the high cost of these materials has severely limited their use. Titanium was thoroughly explored for use in this application, but it is difficult to weld and costs approximately 10 times as much as carbon steel. As a result, only a handful of titanium strings have been manufactured.

Workover & Completion Applications

CT is routinely used as cost-effective solution for numerous workover applications. A key advantage of CT in this application is the ability to continuously circulate through the CT while utilizing CT pressure control equipment to treat a live well. This avoids potential formation damage associated with well killing operations. The ability to circulate with CT also enables the use of flow-activated or hydraulic tools.

Other key features of CT for workover applications include the inherent stiffness of the CT string. This rigidity allows access to highly deviated/horizontal wellbores, and the ability to apply significant tensile or compression forces downhole. In addition, CT permits much faster trip times as compared to jointed pipe operations.

Common CT Workover Applications

Some of the more common CT applications for workover operations are listed below.

Overview of Selected Workover Applications

Pumping Applications

- Removing sand or fill from a wellbore
- Fracturing/acidizing a formation
- Unloading a well with nitrogen
- Gravel packing
- Cutting tubulars with fluid
- Pumping slurry plugs
- Zone isolation (to control flow profiles
- Scale removal (hydraulic)
- Removal of wax, hydrocarbon, or hydrate plugs

Mechanical Applications

- Setting a plug or packer
- Fishing
- Perforating
- Logging
- Scale removal (mechanical)
- Cutting tubulars (mechanical)
- Sliding sleeve operation
- Running a completion
- Straddles for zonal isolation
- Drilling

Removing Sand or Fill from a Wellbore

The removal of sand or fill from a wellbore is the most common CT operation performed in the field. The process has several names, including sand washing, sand jetting, sand cleanout, and fill removal. The objective of this process is to remove an accumulation of solid particles in the wellbore. These materials will act to impede fluid flow and reduce well productivity. In many cases CT is the only viable means of removing fill from a wellbore. Fill includes materials such as formation sand or fines, proppant flowback or fracture operation screenout, and gravel-pack failures.

The typical procedure involved in this application is to circulate a fluid through the CT while slowly penetrating the fill with an appropriate jetting nozzle attached to the end of the CT string. This action causes the fill material to become entrained in the circulating fluid flow, and is subsequently transported out of the wellbore through the CT/production tubing annulus. Where consolidated fill is present, the procedure may require the assistance of a downhole motor and bit or impact drill.

An alternative fill removal approach is to pump down the CT/production tubing annulus and allow the returns to be transported to surface within the CT string. This procedure, called reverse circulation, can be very useful for removing large quantities of particulate, such as frac sand, from the wellbore. It may also be applied when a particular wellbore configuration precludes annular velocities sufficient to lift the fill material. Reverse circulation is suitable only for dead wells.

Unloading a Well with Nitrogen

The process of using CT to unload a well with nitrogen is a quick and cost-effective method used to regain sustained production. A typical field scenario consists of a wellbore that has developed a fluid column with sufficient hydrostatic pressure to prevent the reservoir fluid from flowing into the wellbore. Displacement of some of this wellbore fluid with nitrogen reduces the hydrostatic head, and this reduction of BHP allows the reservoir fluid to again flow naturally into the wellbore. If the wellbore conditions are suitable (pressure, fluid phase mixture and flow rate), production will continue after nitrogen pumping ceases.

There are numerous benefits associated with the use of CT for a nitrogen kickoff operation. The rate and depth of the nitrogen injection can be adjusted to fit a wide range of field conditions. The procedure also provides a ready source of uncontaminated production fluid samples (oil, formation water). And, the procedure is extremely simple from an operational standpoint, as only a small amount of equipment and a limited number of field personnel are necessary.

Fracturing / Acidizing a Formation

This CT application has experienced significant growth in recent years, and provides several advantages versus conventional formation treatment techniques. In particular, CT provides the ability to quickly move in and out of the hole (or be quickly repositioned) when fracturing multiple zones in a single well. CT also provides the ability to facture or accurately spot the treatment fluid to ensure complete coverage of the zone of interest. When used in conjunction with an appropriate diversion technique, more uniform treating of long target zones can be achieved. This is particularly important in horizontal wellbores. At the end of the formation treating operation, CT can be used to remove any sand plugs used in the treating process, and to lift the well to be placed on production.

One of the earlier concerns with CT fracturing was the erosion effects that occur when proppant is pumped during the fracturing operation and the resulting impact on CT string life. An ultrasonic thickness (UT) gauge is now used on location to measure CT thickness during the job. Data from these UT measurements can be used to adjust the CT fatigue models, and to accurately monitor remaining CT string life.

Drilling Applications

Coiled tubing drilling (CTD) has been utilized on a commercial basis for many years, and can provide significant economic benefits when applied in the proper field setting. In addition to potential cost advantages, CTD can provide the following additional benefits:

- Safe and efficient pressure control
- Faster tripping time (150+ ft/min)
- Smaller footprint and weight
- Faster rigup/rigdown
- Reduced environment impact
- Less personnel
- High speed telemetry (optional)

In general, CTD can be divided into two main categories consisting of directional and non-directional wells. Non-directional wells use a fairly conventional drilling assembly in conjunction with a downhole motor. Directional drilling requires the use of an orienting device to steer the well trajectory, per the well plan. CTD can then be further segmented into over-balance and under-balanced drilling applications.

Bit design and selection for CTD follows the same theory as is used in conventional rotary drilling. However, CTD generally uses higher bit speeds at lower weight on bit as a result of the structural differences in CT versus jointed pipe.

Non-Directional Wells

Non-directional wells represent the largest CTD application, and these are defined as a well that lacks downhole tools to control direction, inclination and/or azimuth. Much of the CTD work performed to date involved shallow gas well development in Canada, but it has also been used for shallow water injection wells and for "finishing" operations. A primary advantage that CTD provides in this application is the speed of the rig up/down operation, and the continuous rate of penetration (no delays to add stands of jointed pipe).

The majority of this CTD work has been performed with hole sizes less than 7 in., but hole sizes up to 13 3/4 in. have been successfully drilled. Much the same as in conventional drilling, drill collars can be used in low angle wells to control inclination build-up and apply weight on bit for CTD applications.

Directional Wells

This type of CTD application utilizes an orienting device in the bottomhole assembly (BHA) to control the wellbore trajectory as desired. CTD for this application can include new wells, extensions, side-tracks through existing completions, horizontal drainholes, or side-tracks where the completions are pulled. However, the primary use of CTD for directional wells is to directionally drill into new reservoir targets from existing wellbores.

Directional drilling with CT has some fundamental differences compared to conventional rotary drilling techniques. One of the basic differences is the need for an orienting device to control the well trajectory, since CT cannot rotate. Orienting devices control hole direction by rotating a bent housing to a particular orientation (toolface) or controls the side loading at the bit to push the assembly in a particular direction. This control over the BHA provides directional control for CTD applications.

A steering tool is used to measure inclination, azimuth, and tool face orientation. Two basic types of steering tools are used for directional drilling with CT. Electric steering tools are used in conjunction with a cable inside the CT to transmit data to surface. Mud pulse tools comprise the second type of steering device for CTD applications. Mud pulse steering tools transmit data to the surface by generating pressure pulses in the mud.

In addition to orientation and steering devices, some BHAs utilized for CTD are equipped with additional measurement tools, including gamma ray, casing collar locator, accelerometers (shock load measurements), pressure (internal and annulus) and weight on bit.

Wellbore Hydraulics and Wellbore Fluids

There are some key fluid design parameters to keep in mind for CTD applications versus traditional rotary drilling. For example, all CTD operations require the fluid to travel through the entire tubing string regardless of the current drilling depth. In addition, the frictional pressure loss for CT on the reel is considerably larger than for straight tubing. Thus, for optimum hydraulic performance, the drilling fluid must behave as a low viscosity fluid while inside the CT, and as a high viscosity fluid in the annulus (for efficient cuttings removal).

Another key difference associated with CTD is the absence of tubing rotation while drilling. Jointed pipe is rotated during conventional drilling operations, and this movement helps keep the drill cuttings suspended in the drilling fluid, so they can be lifted to surface. Since the tube doesn't rotate in CTD applications, hole cleaning can be more challenging in heavily deviated/horizontal applications. This effect is partially offset by the smaller cuttings produced with CTD (higher RPM, lower weight on bit). In addition, special visco-elastic fluids have been developed for CTD, that change their rheology according to the local shear rate, i.e., become more viscous in the annulus (lower shear rate) to improve cutting suspension.

Overbalanced CTD

As with conventional well drilling operations, the drilling fluid is used for controlling subsurface pressure and the CTD drilling fluid systems are typically smaller versions of conventional systems. Conventional well control principles apply except that the CT string limits the fluid flow rate and the frictional pressure loss varies with the ratio of tubing on/off the reel.

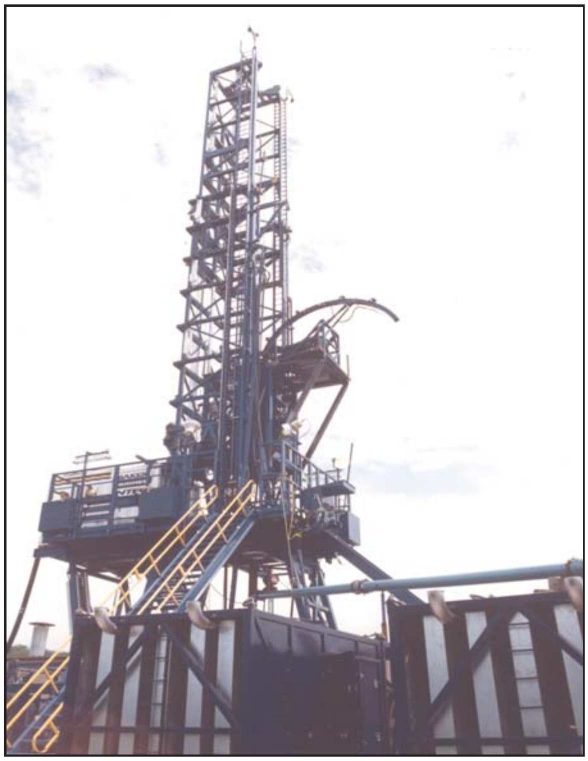

Figure 16: CT Drilling Unit Mast and Substructure for CT Sizes through 5 1/2 in.

UNDERBALANCED CTD

To date, most underbalanced CTD activity has been for re-entry operations, but new wells could also benefit from this approach. CTD is ideal for this underbalanced applications because of it's inherent well control system. In addition, underbalanced "finishing" is a variation of underbalanced drilling used extensively in Canada and gaining acceptance in other areas. For finishing operations, a conventional rig is used to drill to the top of the reservoir and casing is run. From this point, CTD is utilized to drill into the reservoir with underbalanced drilling techniques. This technique attempts to leverage the respective strengths of both drilling approaches. Conventional drilling can be faster (less expensive) in the large diameter, unproductive uphole drilling intervals, while underbalanced CTD is faster (less expensive) in the producing interval. CTD is also better suited to deal with the pressure/produced hydrocarbons from the productive interval.

Pipeline Applications

CT can be used as an effective tool for numerous pipeline applications, including:

- Transportation of inspection tools
- Removing organic deposits and hydrate plugs
- Removing sand or fill
- Placing a patch or liner to repair minor leaks
- Setting temporary plugs

Land

Land-based CT operations in pipelines are similar to CT operations in horizontal wellbores with a few notable exceptions. First, the injector head must supply all the force required to RIH with the CT. The lack of a vertical CT section means that none of the CT weight is available to push on the CT ahead of it. Second, the injector head must be oriented horizontally at the entrance to the pipeline. This requires a special mounting frame and an injector that will operate efficiently while lying on its side. Finally, the injector head will be required to snub the CT into the pipeline during the entire RIH operation, and thus the weight measuring device (weight cell) must be configured for accurate measurement of snubbing forces.

Offshore

CT operations in pipelines from an offshore platform are similar to operations in extended reach wellbores that kickoff at a shallow depth. The primary difference is that the path of the CT between the injector and the conduit on the sea floor may include several short radius bends. These bends impart a high drag force, and increase the snubbing force requirement on the CT injector. Since the injector may have to snub the CT into the pipeline during most of the RIH phase of the operation, the CT weight measuring device (weight cell) must be configured for accurate snubbing force measurement.

Limitations

Regardless of the operational environment (land vs. offshore), post-helical buckling lockup of the CT is typically the primary limiting factor for pipeline operations. Lockup limits both the CT's horizontal reach into the pipeline, as well as the maximum available force that can be transmitted by the CT.

In addition, the radial clearance between the CT and the pipeline conduit is usually much larger when compared to standard wellbore operations. This effectively reduces the downhole critical force required to helically buckle the CT. Also, oil pipelines typically have an internal coating of highly viscous oil or wax that significantly increases the CT sliding friction coefficient. This excessive drag against the CT can also reduce the length of CT that can be pushed into the pipeline prior to buckling.

Overcoming Pipeline Drag Limitations

A common approach to reducing CT drag in conventional operations is the use of liquid friction modifiers to reduce the coefficient of friction between the CT and wellbore. This technique can be used in pipeline operations, and may provide a sufficient operating window to perform the desired operation.

Another typical approach utilized to overcome CT drag in pipelines is the addition of "skates" to the CT string at regular intervals. A skate resembles a rigid centralizer or stabilizer, with a roller on the end of each arm (blade). The skates serve to support the CT and prevent it from dragging against the inside of the pipeline. This effectively converts the drag from sliding friction to rolling friction. It's not uncommon for this approach to reduce the effective friction coefficient by 75%, which allows the CT to be pushed much farther into the pipeline without experiencing lockup.

In addition to the use of skates, hydraulic "thrusters" can be used to successfully reach the desired length inside the pipeline. A thruster consists of jets aimed in a direction opposite to the desired CT movement direction. This action applies a tensile force to the CT, and act to literally pull the CT string along the pipeline. Providers of the thruster service claim that the combination of thrusters and skates can enable CT operations to be successfully performed in horizontal pipelines up to five miles from the injector head point.

Permanent Installations

There are multiple permanent CT installations that go beyond the pipeline applications discussed in the previous section. These applications include flowlines, velocity strings, and control lines. The largest market for composite CT is for flowline and pipeline installations. Velocity strings are the final resting place for many used CT strings. And, control lines are the largest market for small diameter CRA tubing.

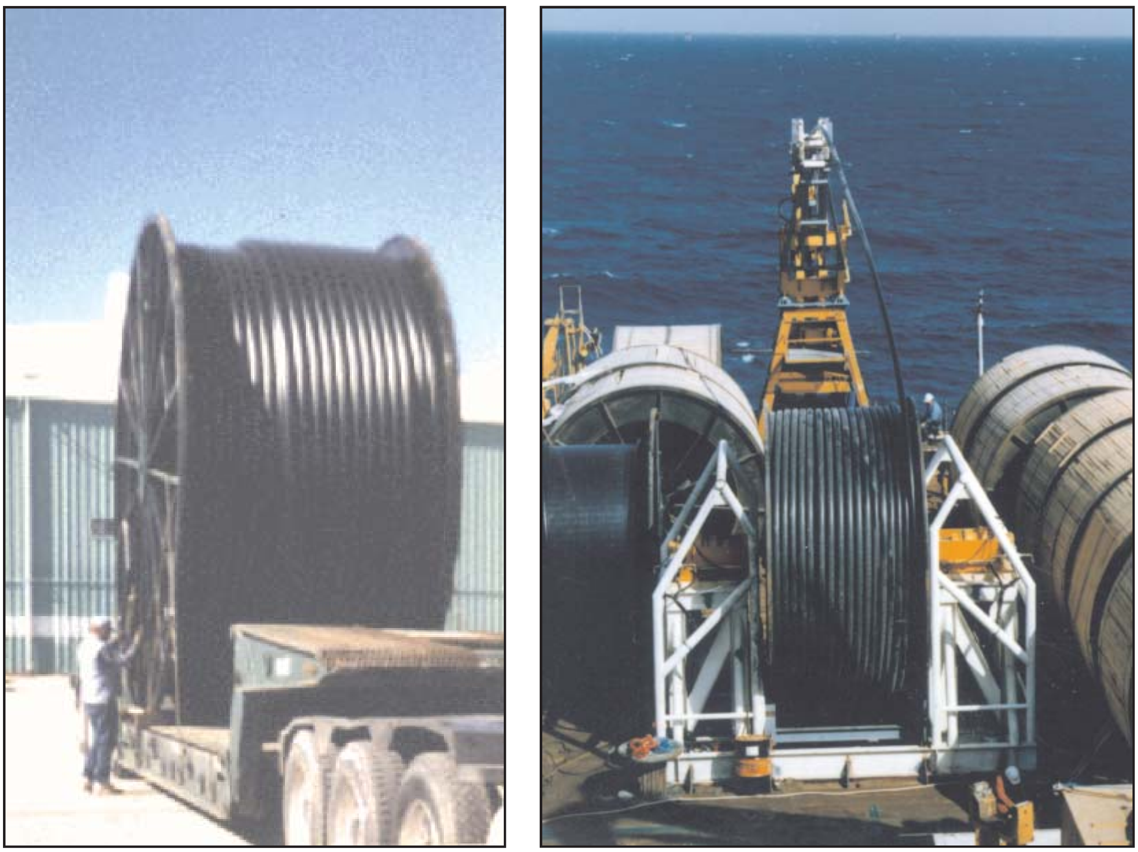

Figure 17: 4 1/2 in. Offshore Flowline in the Gulf of Suez

Offshore Flowlines

In permanent installations, CT may be used as a flowline between offshore structures. The CT installation costs in this application are normally much less than for conventional barge-lay installations of welded line pipe. Prior case studies have documented savings in excess of 50 percent. In addition, the lower internal surface roughness of CT flowlines provides for lower frictional pressure loss than equivalent size jointed pipe. A 15-20% reduction in pressure loss (pump horsepower) has been reported with CT flowlines. This provides additional economic benefit in the form of lower operating and maintenance costs.

The largest CT flowline installed through year 2000 is 4 1/2 in. OD. However, CT suppliers have produced short lengths of tubing up to 6 5/8 in. OD for this application.

Individual sections of flowline can be connected mechanically (use of slip-type connectors) or by welding, with the latter being more common. "Full bore" socket connections can be installed and inspected at the CT mill. During installation, the socket requires only a single weld and inspection for each new reel added to the flowline. This approach reduces installation time, and the full bore does not disrupt the flow or future pigging operations.

Velocity Strings

The use of velocity strings is a common practice, especially in depleted gas wells. The objective of this permanent installation is to decrease the available production surface area within the wellbore such that the produced gas has sufficient energy to carry any produced liquids to surface. Small diameter (OD < 2 in.) velocity strings are often constructed from used CT work strings. A downhole hydraulic simulator is often used to estimate the performance of the string over a range of expected operating conditions. This modeling can help design a velocity string that maximizes well production. However, for these depleted wells, the choice of CT size and installation hardware may be heavily dependent on the price/availability of used CT strings.

Control Lines

CT is often used as the hydraulic control line connection between production facilities and subsea equipment. Each installation typically requires multiple control lines. As a result, multiple lines are normally bundled into a single line (umbilical) to reduce installation costs and to make the system more robust. The DEEPSTAR joint industry project developed the CT umbilical control line shown in Figure 18. It consists of four separate 3/4 in. CT strings surrounded by insulation, and further protected by two layers of armor wire. Approximately 33,000 ft. of this control line was installed in the North Sea in 1995.

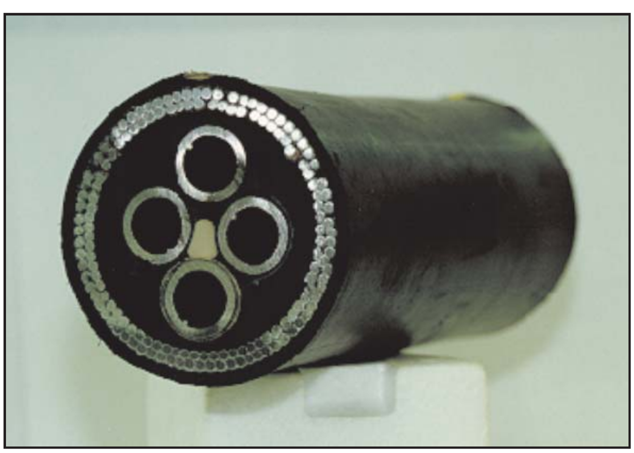

Figure 18 CT Control Line (Umbilical) Developed by DEEPSTAR

Nomenclature

BHA	Bottom Hole Assembly
BHP	Bottom Hole Pressure
BOP	Blowout Preventer
CRA	Corrosion Resistant Alloy
CT	Coiled Tubing
CTD	Coiled Tubing Drilling
ft.	Feet
ft/min	Feet per Minute
HRC	"Hardness" value, as determined by the Rockwell C hardness test
in.	Inch
OD	Outer Diameter
POOH	Pull Out Of the Hole
RIH	Run In Hole
TIG	Tungsten Inert Gas
UT	Ultrasonic Thickness

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