



Supplemental Section A-1

Coiled Tubing

COILED TUBING

INTRODUCTION

A coiled tubing unit is a portable, hydraulically powered well intervention system designed to inject and retrieve a continuous string of tubing into larger production pipe or casing strings. The four basic components of the unit are a power source, a service reel, an injector/extractor and a control console. The tubing may range in sizes from 0.75 inches to 3.5 inches outside diameter (OD), although other sizes are sometimes manufactured for special applications.

The coiled tubing (CT) itself is a continuous string of flexible steel tubing that is wound onto a reel for transport and deployment. The unit is usually mounted on a trailer or a skid and is therefore easily transported to and from job locations. When rigged up over the wellhead, the tubing is injected into the well through a control head (stripper) that seals off the tubing and makes a pressure-tight connection, thereby permitting the unit to work on live wells. Modern day coiled tubing units, using sophisticated hydraulic systems integrated with computer software, are capable of performing a full range of well completion/workover operations. Some of the primary advantages and disadvantages of coiled tubing units are listed below.

ADVANTAGES

- Coiled tubing can be deployed and retrieved while continuously circulating fluids.
- Coiled tubing can work against well pressure. There is no need to kill the well.
- The body of the coiled tubing has no connections to make or break.
- CT units are highly mobile and compact.
- Formation damage is minimized when performing remedial work without killing the well.
- Completion tubulars can remain in place; the coiled tubing is inserted into the production tubing.
- CT can perform continuous well control operations with pipe in motion.

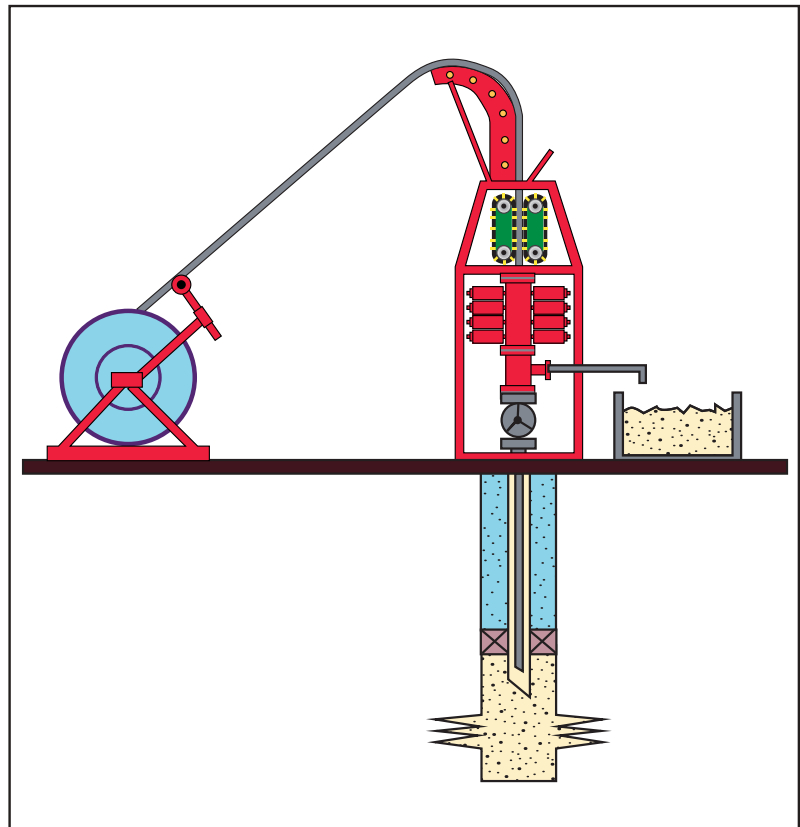


Figure a-1: Coiled Tubing in a Well

DISADVANTAGES

- CT is subjected to bend cycling, fatigue and requires frequent tubing replacement.
- Coiled tubing has a thinner wall thickness as compared to jointed tubing. This limits the tensile load strength of the tubing.
- The combination of bend cycle fatigue and thin wall dimensions results in reduced yield strength (burst and collapse limits) of coiled tubing relative to most jointed pipe.
- The length of CT that can be spooled onto a reel is limited due to height and weight which can in turn, cause transport concerns.
- Circulation rates through coiled tubing are low and circulating friction pressures high when compared to similar sizes of jointed tubing.



Figure a-2: Truck Mounted Coiled Tubing Unit



Figure a-3: Injection Head

SECTION 1: COILED TUBING UNITS

The main components that make up a complete CT unit can vary somewhat due to the fact that there are several manufacturers that design and build the individual components. Regardless of specific design, from the standpoint of function, all CT units are much the same. The following discussion addresses the primary components of the most common type of unit, equipped with a vertical, counter-rotating injector drive assembly.

The individual components of these units are:

- Prime Mover
- Service Reel
- Injector/Extractor
- Gooseneck
- Control Console
- Coiled Tubing String

PRIME MOVERS

Most coiled tubing units are powered by diesel engines driving multi-stage hydraulic pumps. The size of the prime mover assembly varies with the requirements of the hydraulic drive unit, which may range from a simple power take-off assembly on a bobtail land unit to self-contained offshore skid packages. Most hydraulic systems for the units are rated from 3,000 to 5,000 psi.

Most units use a minimum of five hydraulic circuits. Each circuit can be individually controlled; that is, both the circuit pressure and the direction of flow of hydraulic fluid can be monitored and adjusted by the operator.

The five basic hydraulic circuits are:

- The Main Power Circuit provides fluid power to operate the tubing injector/extractor, which deploys and retrieves the tubing from a well.
- The Pilot Circuit provides fluid power to the valve network that controls the primary components of the system.
- The Reel Power Circuit provides fluid power to operate the service reel and crane (on crane-equipped units).

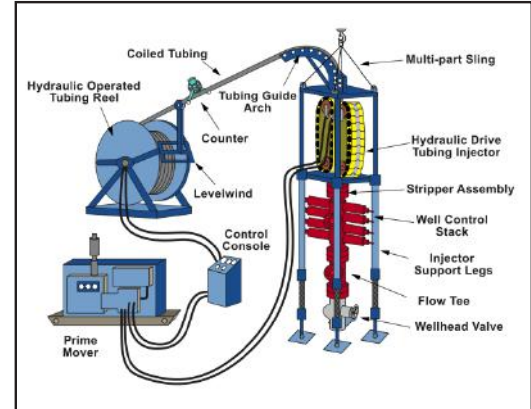


Figure a-4: Coiled Tubing SyStEM



Figure a-5: Coiled Tubing unit Prime Mover

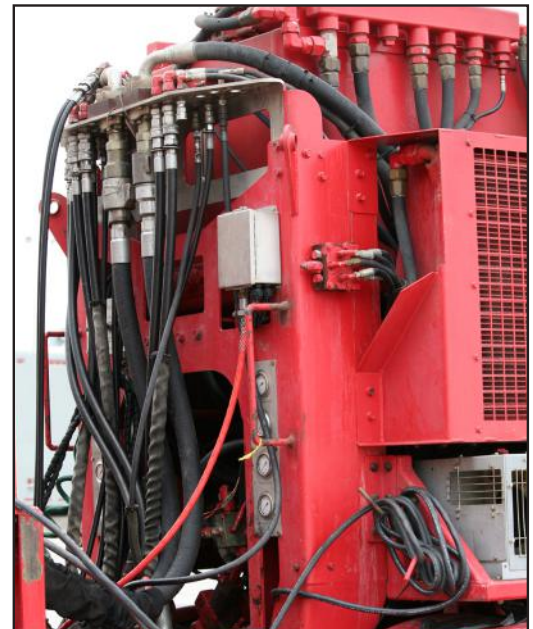


Figure a-6: Hydraulic CirCuTS on CT unit PoWer PaCk

- The BOP Power Circuit provides the fluid power to operate the blowout preventers. Similar to most drilling and workover rigs, the BOP circuit pressure is usually 3,000 psi. An accumulator is incorporated into the circuit to provide an emergency supply of pressurized fluid, should the power pack fail.
- An Auxiliary Circuit provides standby fluid power for emergencies and for the operation of non-standard accessories.

SERVICE REEL

The service reel serves as the coiled tubing storage mechanism during transport and as the spooling device during operations. The inboard end of the unit is connected to a high pressure rotating swivel joint mounted directly onto the reel shaft through a hollow segment of the shaft. The swivel joint is secured to a stationary section of piping which is further connected to the pumps (liquid or gas); therefore, the well can be circulated continuously while simultaneously moving the tubing within the well. A high pressure shutoff valve is provided between the tubing and the reel shaft for emergency. This valve isolates the tubing from surface pump lines.



Figure a-7: ServiCe reel

The high-pressure rotating swivel and piping must have a working pressure rating at least as high as the pressure rating stipulated in *API RP 5C7*. Special consideration is given to cases in which the swivel and piping may come in contact with wellbore fluids, and at least one shut-off valve should be incorporated between the pump and the high-pressure swivel. The swivel and associated piping must have a pressure rating at least as high as the internal yield pressure of the tubing, whichever meets the criteria for the specified job. The reel is provided with a mechanism that prevents the reel drum from accidental rotational movement in such a way that the reel support structure is secured during normal operations.

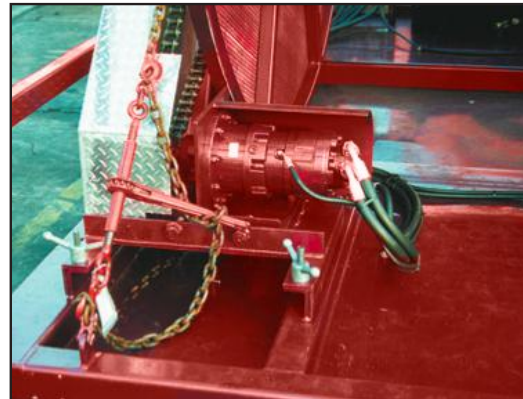


Figure a-8: reel Hydraulic drive MoT or

Some coiled tubing strings are used specifically for electric wireline services. In these cases, the wireline is run inside the coiled tubing and is terminated on the reel shaft at a pressure bulkhead as it exits the tubing. The multi-conductor cable runs from the pressure bulkhead to a rotating electric connection (collector ring) similar to those found on electric wireline units. The electric connection is located on the reel shaft, opposite the fluid rotating joint.

Service reel rotation is controlled by a hydraulic motor that can be mounted for direct drive on the reel shaft or operated by a chain-and sprocket drive assembly. This motor is used to maintain a constant pull on the tubing, thereby keeping it tightly wrapped on the reel. When injecting the tubing into a well, a slight backpressure is applied to the reel motor to allow the injector to pull the tubing off of the reel as well as to hold the tubing in tension between

the injector and reel. The tension provided by the reel on the coiled tubing between the reel and the injector is commonly called *reel back-tension*. When tubing is retrieved from the wellbore, the pressure to the reel motor is increased to allow the reel rotation to keep up with the extraction rate of the tubing injector. The reel drive system produces sufficient torque to provide the tension required to bend the tubing over the gooseneck and onto the reel. In addition, the reel drive system should generate enough torque to accelerate the reel drum from stop to maximum injector speed at an acceptable rate. The torque must be capable of handling a fully loaded reel drum when the tubing is full of working fluid.

The coiled tubing that is stored on the service reel has a potential for unwrapping or “springing” outward if the back-tension is released; therefore, the free end of the tubing must always be kept in tension. That presents no problem during normal operations because the reel back-tension prevents the reel from springing. However, when not in operation, the free end of the coiled tubing must be restrained.

REEL BRAKE

The reel package includes a hydraulically-activated braking system. The primary function of the *reel brake* is to stop drum rotation if the tubing accidentally parts between the reel and the injector, or to slow the reel if runaway conditions develop. Some units incorporate a device in their hydraulic power systems that imposes backpressure at the motor to slow the reel down. Other units employ a friction pad braking system that is hydraulically or mechanically applied on the outer diameter of the reel flange to aid in slowing the reel rotation. The reel brake is not intended to halt uncontrolled runaway tubing; it only offers resistance in order to slow reel rotation. If hydraulic pressure is lost, the brake can also be used to reduce the tendency of the tubing to spring free. When the reel is being transported, the braking system prevents the tubing from springing.

LEVEL WIND ASSEMBLY

The tubing is guided to the service reel by a *level wind assembly* that properly aligns it as it is wrapped onto, or spooled off of the reel. The level wind assembly spans the entire width of the service reel drum and can be raised to the height which will line the tubing up between the injector, the gooseneck and the reel. A mechanical depth counter is usually mounted on the level wind assembly. The counter incorporates a series of roller heels placed in contact with the tubing and has an arrangement of gears that mechanically measures the length of the tubing that passes through it. The level wind assembly must be strong enough to handle both the bending and side loads of the coiled tubing as it is deployed. The free end of the coiled tubing is

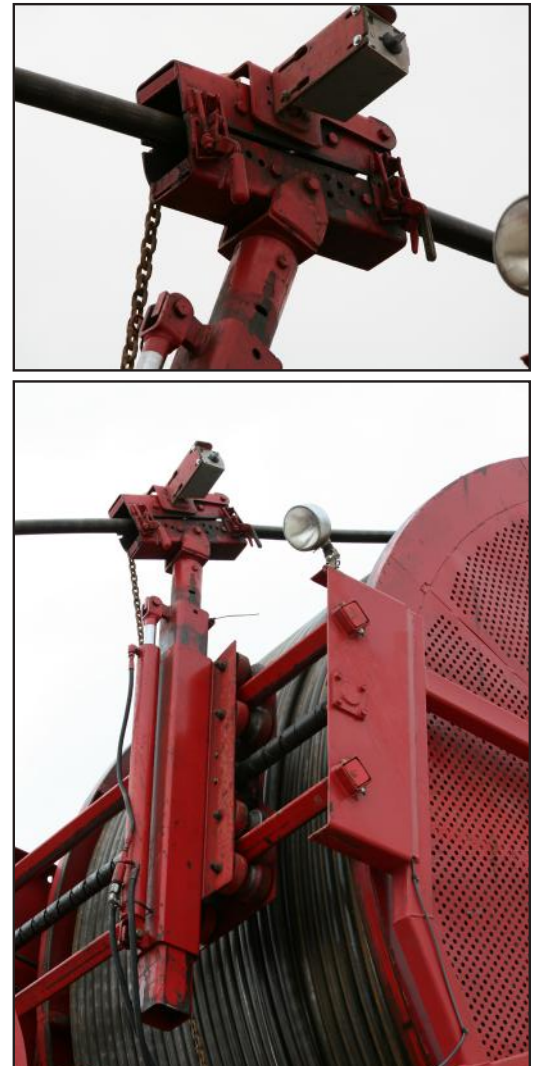


Figure a-9: level Wind aSSeMbly

usually clamped to the level wind assembly to prevent the coiled tubing from springing when it is being transported. The level wind assembly may also be equipped with a hydraulically or pneumatically operated clamp that can be manipulated to secure the coiled tubing at the cross-bar of the level wind assembly.

In many cases, the service reel is equipped with a system for lubricating the outside of the coiled tubing to prevent atmospheric corrosion and reduce the frictional loads encountered when deploying the tubing through the energized stripper assembly. The lubrication system must conform to all local and federal regulations. Sprayers that atomize lubricants onto the reel are not recommended for use with highly flammable materials.

TUBING INJECTOR/EXTRACTOR

Commonly called the *injector*, the injector/extractor supports the full weight of the tubing, plus any attached tools, while at the same time providing the force required to deploy and retrieve the tubing within the wellbore at varying speeds controlled by the operator.

There are several types of counter-rotating chain drive injectors. All injectors manipulate the continuous tubing string by using two opposing sprocket-drive traction chains, which are powered by counter-rotating hydraulic motors. The drive chains are fabricated with interlocking gripper blocks mounted between the chain links. The gripper blocks are designed to minimize damage to the coiled tubing and may be machined to fit the circumference of the tubing string or cast in a “V” shape to accommodate variable OD sizes of the tubing. The coiled tubing is loaded by opposing gripper blocks with sufficient force so that the resulting friction forces are greater than the axial tubing loads, tension or compression, but less than the force required to collapse the tubing. This applied force can be provided in one of three ways for vertical, counter-rotating chain drive injectors.

In two of the three cases, the gripper blocks are forced onto the tubing by hydraulically loading a series of rollers, either installed as sets of skates behind the chains, or integrated within the chains. In the case where the gripper block chain contains cam rollers, the rollers are loaded by flat, hydraulically-actuated support bars installed directly behind the chains. In another system, the back of the chain is flat and the rollers are contained in the support bars or skates installed behind the chains.



Figure a-10: griPPER bloCks



Figure a-11: Coiled Tubing injeCT or Head

A third type of chain loading design uses a dual-chain system in which an inner chain is used to support the normal force loading of the outer chain. Other injector designs include opposed counter-rotating chain block systems, arched-chain roller drive, single-chain opposed-gripper drive systems and a sheave-drive system.

Hydraulic cylinders are used to supply the traction pressure and subsequent force applied to the coiled tubing in all of these traction-loading systems. In addition, the chain-loading designs require an emergency system to maintain traction in case hydraulic pressure is lost. The backup system usually consists of an accumulator and a manual hydraulic pump located in the control cabin.

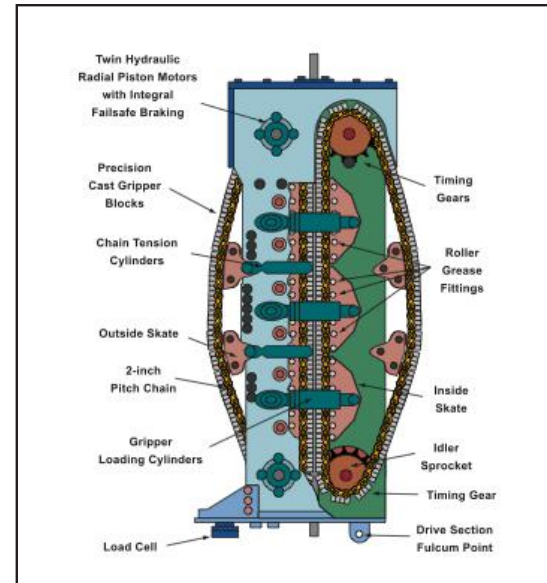


Figure a-12: CuT aWay vieW oF ST aCk loaded injeCT or

Over the course of time, loading reversals will cause the chain drive system to wear and stretch. In addition to hydraulically loading the gripper blocks onto the coiled tubing, the chain drive system must be equipped to apply tension to minimize slack in the chains. The chain tension must be increased when snubbing to avoid buckling the chain. Hydraulic motors are used to drive the gripper block chains over the chain drive sprockets. A hydraulic counterbalance system provides dynamic braking when hydraulic pressure is removed from the hydraulic motors. Many motors have built-in hydraulically-released brakes that automatically lock when hydraulic pressure is removed from the motor. In other cases, separate external mechanical brakes are used.

The injector must be stabilized in order to minimize bending loads on the BOP stack and the wellhead. It may be stabilized above the wellhead using telescoping legs or with a hydraulically-elevated load frame commonly called a *jackstand*. Telescoping legs are generally used in rig-ups where the height of the injector or the wellhead design does not permit the use of a jackstand. When telescoping legs are used, the top sections are inserted into the four slots located on the perimeter of the injector frame and then secured with pins at the required height. Footpads are placed beneath each leg to distribute the weight of the injector to the surface grade. The legs can be stiffened by tightening turnbuckles mounted beneath leg sections. Telescoping legs impose the weight and operating forces of the injector and BOP stack directly on the wellhead.

When an unobstructed surface is available, for example on offshore platforms, it is recommended that the injector be supported by a jackstand. Once the desired height is achieved, the four legs are pinned and secured in place. The base of the jackstand distributes the injector weight evenly around the perimeter of the stand. Jackstands provide greater safety and stability than telescoping legs, as well as latitude in releasing overhead crane support in non-critical service.

A mast or rig-type structure is used on some locations. On locations where a mast is required, care must be taken to minimize the axial load placed on the wellhead by the injector and the BOP stack. The injector should be secured

within the mast to minimize the motion of the injector during service. In all cases, the injector should be secured to the ground or a structure with at least one chain attached to the front of the frame facing the reel and two chains from the rear of the frame. The injector should never be secured at the wellhead or a production tree.

GOOSENECK (TUBING GUIDE ARCH)

The counter-rotating, opposed-chain injectors use a *tubing guide arch* (often called a *gooseneck*), which is located directly above the injector. The gooseneck supports the tubing through the entire bending radius (90 + degrees) and guides it from the reel into the injector chains. The gooseneck incorporates a series of rollers or pads along the arch to support the tubing and includes a series of upper rollers to center the tubing as it travels over the arch. The number, size, material and spacing of the rollers can vary significantly with different gooseneck designs. The radius of the gooseneck arch is defined as the radius of curvature of the centerline of the lower rollers.

API GOOSENECK RECOMMENDATIONS	
TUBING SIZE (INS.)	RADIUS (INS.)
1-1/4	48 - 72
1-1/2	48 - 72
1-3/4	72 - 96
2	72 - 96
2-3/8	90 -120
2-7/8	90 -120
3-1/2	96 -120

CONTROL CABIN

A coiled tubing unit is operated from a console situated within a weatherproof *control cabin*. The operator's console contains the controls and gauges used to function and monitor all of the components of the unit. The control cabin may be skid-mounted; for example, when working offshore, or it may be permanently mounted as with land units. The size of the cabin and the variety of controls on the operator's console may vary somewhat, depending on the specific unit requirements and equipment. The primary controls and gauges on the consoles common among all units are discussed below.



Figure a-13: Inside a Coiled Tubing unit

The reel and injector motors are activated by valves that determine the direction of tubing motion and operating speed. Also located on the console are the controls that regulate the drive chain, the stripper and the BOPs.



Figure a-14: MeCHaniCal dePTH Counter

WEIGHT INDICATOR

A weight indicator measures the tensile load in the coiled tubing just above the stripper. There is also an indicator which measures the compressive force (often referred to as negative weight) in the coiled tubing below the injector when the CT is being snubbed into a well. Beside the weight of the string, total load is affected by, 1) friction through the stripper, 2) reel back-tension, 3) fluid density (both inside and outside the coil) and 4) surface (wellhead, or annulus) pressure.

MEASURED DEPTH (MD)

Measured depth is the length of coiled tubing that is deployed through the injector. Measured depth readings may be significantly different from the actual depth of the coiled tubing in the well due to stretch, thermal expansion and mechanical elongation. Measured depth can be directly observed at several places on a coiled tubing unit using a friction wheel that contacts the tubing. It may also be obtained indirectly by measuring the rotation of the injector shafts. Measured depth is recorded as a function of time and in relation to the internal pressure applied to the coiled tubing string for use in tubing fatigue calculations (Section 2).

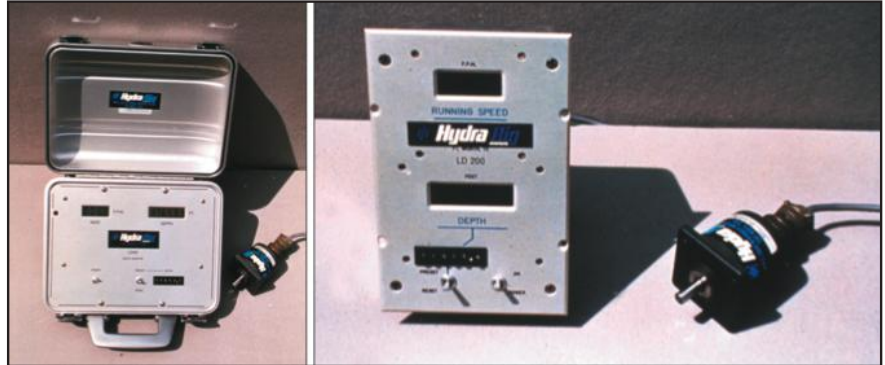


Figure a-15: eleCTriC dePTH CounTer & SPeed indiCa

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SPEED (RATE OF DEPLOYMENT)

Speed is calculated and recorded as the change in measured depth over a specified time.

CIRCULATING PRESSURE

Surface Pump pressure is monitored and displayed to the operator and is recorded for use in fatigue calculations (see Section 2).

WELLHEAD (ANNULUS) PRESSURE

The well pressure around the outside of the coiled tubing at the wellhead is monitored and displayed on the console. The pressure measurement systems for both the coiled tubing and wellhead pressures incorporate a method of preventing the well fluids from exhausting into the control cabin in the event of gauge failure.

Other controls and gauges that are monitored at the console include:

- Engine and power pack controls
- Separate pressure and adjustment for each hydraulic circuit
- Injector operating pressure and direction

- Reel back-tension
- Traction force applied to the coiled tubing by the injector
- Chain tension required for snubbing and/or taking up slack
- Stripper pressure
- Level wind assembly direction and reel direction
- Accumulator emergency engagement

HYDRAULIC CRANE



Figure a-16: Hydraulic Crane

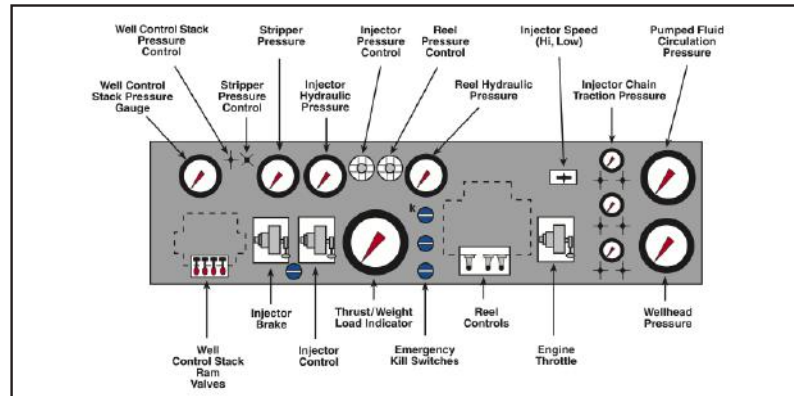


Figure a-17: baSiC Coiled Tubing unit

ConTrolS

A hydraulic crane is often incorporated into the unit package if lifting is not available at the location by other means. The function of the crane is to provide a means of lifting the injector to the Xmas tree as well as to provide support and stability. Free standing injector bases are used for crane-free applications after rigging up. These are used where overhead space, crane capacity or weight prohibits normal rig-up. The injector base may incorporate self-elevating hydraulic cylinders for height adjustment when rigging up and include hydraulic winches used for skidding the assembly across the location. When using a free standing injector base, with or without the support of a crane, jack legs should be extended and secured.

FLUID PUMP

The fluid pump has an intake located in or selected from the desired tanks. Fluid is drawn from the tank, through the pump, to the manifold and lines, where it may be mixed with nitrogen. It goes to the circulating swivel on the tubing reel where it connects to the tubing.

TANKS AND MIXING/STORING EQUIPMENT

Fluid tanks usually have two or three compartments but are available in other designs. The suctions of the tank may either be on the sides, several inches from the bottom, or cement-type tanks where the suction is on the bottom. Centrifugal pumps and a mixing hopper are often included, as well as a filtering unit.

ACCESSORIES AND SUPPORT EQUIPMENT

Some operations, such as coiled tubing drilling (CTD), require much the same type of equipment as found on a drilling rig. Multiple tanks, shale shakers and a mixing system may be used. Pressure control equipment may include mud/gas separators, degassers and more complex choke manifolds. Remote adjustable chokes are sometimes used for high pressure operations or where gas may be circulated from the well.

PRESSURE CONTROL EQUIPMENT

The pressure control equipment included on the majority of coiled tubing units consists of a hydraulically-operated stripper mounted at the base of the injector. The standard maximum working pressure rating of the stripper assembly is 10,000 psi. However, some of the newer stripper assemblies are designed for working pressures of up to 15,000 psi. Below the stripper, the most common BOP arrangement is a combination of four ram preventers called a *quad stack*. There may be one or more sets of rams rigged below the quad stack as the job requires. The quad stack and additional rams are generally rated for a minimum working pressure of 10,000 psi. There is high pressure BOP equipment available that is designed for 15,000 psi working pressure. API RP 16ST provides a guide for selecting the minimum pressure control equipment based on the operator's maximum anticipated surface pressure (MASP).

PRESSURE CATEGORIES FOR CT WELL CONTROL EQUIPMENT (API 16ST)			
Pressure Category (PC)	MAASP Range (psig)	*Minimum Rated Working Pressure (psig)	Minimum Number Barriers
PC - 0	0a	3,000	1
PC - 1	1 to 1,500	3,000	2
PC - 2	1,500 to 3,500	5,000	2
PC - 3	3,501 to 7,500	10,000	2
PC - 4	7,501 to 12,500	15,000	2
*Minimum working pressure of the stack shall be equal to or greater than the MOAP			
Note: Maximum Anticipated Working Pressure (MAWP) for a given piece of well control equipment is the highest calculated pressure that a given component will be subjected to during the execution of the prescribed service and/or during contingency service.			

STRIPPERS

The *stripper* is the primary pressure control barrier used in coiled tubing operations. It is positioned along the centerline of the tubing when the tubing is secured in the chain drive assembly. Strippers are annular preventers designed to provide a pressure-tight seal around the coiled tubing when running into or pulling out of a well with pressure at the surface. The seal is achieved by energizing the stripper packer inserts, forcing them against the tubing. The energizing force is hydraulically applied and controlled from the operator's console. The inserts are consumable elements and therefore may require changing during the operation. Stripper sealing elements are available in several different compounds depending on application (heat, pressure, fluid types, gas, etc.)

The most common compounds are listed below.

- *Urethane*: Tough and tolerates abuse. Perhaps the longest wearing compound. It has a wide operating temperature range, -40° to 200° F, but begins to deteriorate rapidly as temperature approaches its upper range.
- *Nitrile*: Most common. Good oil and water resistance, higher temperature range than urethane. Not as wear-resistant as urethane. Operating temperature range is 10° to 350° F.
- *Viton*: Resistant to most oil and gas well chemicals, good resistance to gas permeation. Not as wear resistant as Nitrile. Higher temperature operation range of 0° to 400° F.

There are three types of tubing strippers used in coiled tubing operations: 1) conventional strippers, 2) side-door strippers and 3) radial strippers. Strippers are attached to the lower structure of the injector/extractor assembly and are positioned below the lower gripping area of the chain with tubing guides or stripper guide extension. The guides (or extensions) prevent the work string from deviating from its proper path when well pressure exerts upward force on the tubing, thereby preventing tubular buckling. The most common types of strippers are discussed below.

CONVENTIONAL STRIPPER

Conventional strippers use an energizer, or hydraulic piston, below the sealing elements, which is hydraulically forced upward to make contact with the elements. The stripper sealing elements may be a single circular or two semi-circular elastomer components that fit together in the cylindrical bore of the stripper body, surrounding the work string. A taper on the end of the sealing element corresponds to a taper on the energizer. When force is exerted on the tapers, the elements are forced together creating a pressure-tight seal around the coiled tubing. In order to prevent extrusion at high pressures, the stripper is equipped with a hard Teflon® non-extrusion ring and a bronze bushing retainer that overlap the seam in the split cap. The sealing elements are retained by a cap that fits into the top of the stripper body, secured by two pins. Most conventional stripper assemblies are wellbore pressure energized which assists in forming an effective seal. Access to insert replacement is from the top, within the injector head frame. A greater distance is required between the stripper top and the gripping chains than other type of strippers, an important consideration for buckling when working against high well pressure.

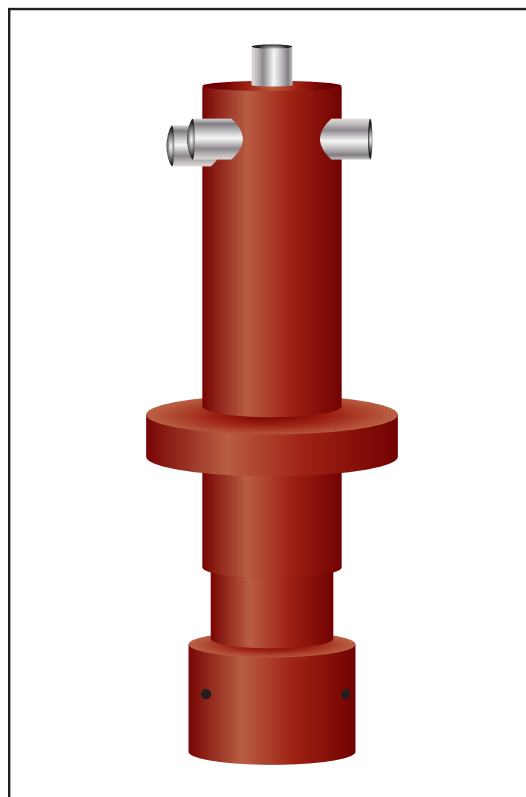


Figure a-18: Conventional STRIPPER

SIDE DOOR STRIPPER

The *side door stripper* was developed to permit easier access to the stripper packer arrangement. The seal elements may be removed through the open window below the injector, simplifying removal while the tubing is in place. Access to the stripper from above is not required, therefore the assembly can be mounted closer to the injector

head chains, which minimizes the chances of buckling between the chains and the stripper. Hydraulic pressure is applied from above the sealing elements.

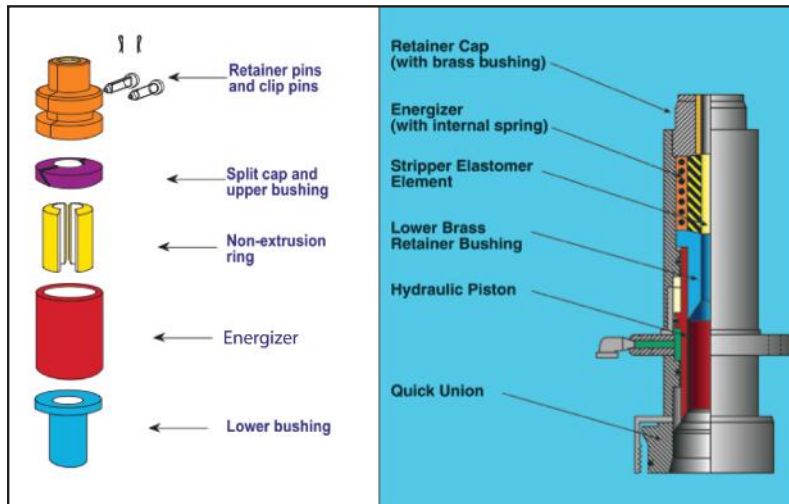


Figure a-19: STRiPPER & CoMPonenTS

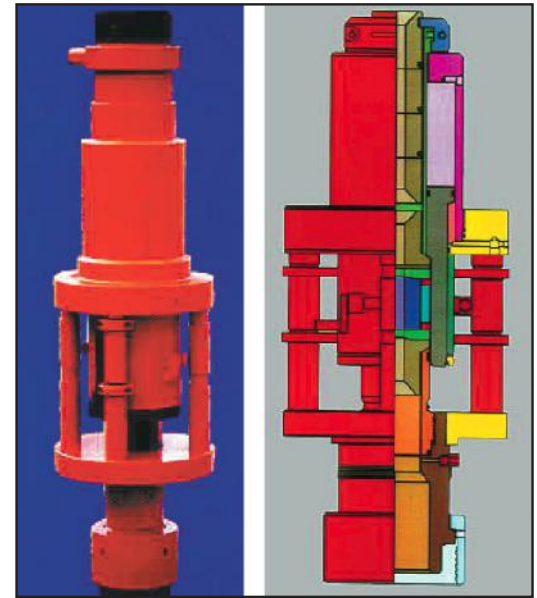


Figure a-20: Side door STRiPPER

RADIAL STRIPPER

Radial strippers are similar in design to pipe rams. Hydraulic fluid forces opposing rams around the coiled tubing to create the seal. The hydraulic actuator pistons also incorporate a visual indicator to indicate the piston's position and to indicate the degree of wear of the sealing elastomers¹. Since the actuators are horizontal, the overall height is reduced when compared to conventional or side-door strippers. The seal elements are changed from the open space below the injector. Radial strippers, have a larger sealing element than conventional or side-door strippers and they provide a longer working life.

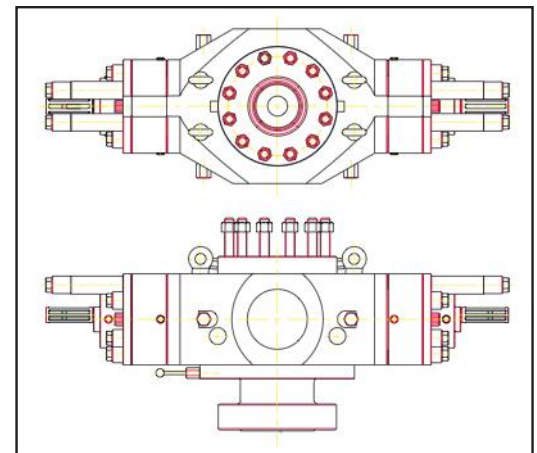


Figure a-21: radial STRiPPER

Strippers are sometimes run in tandem. They can be used simultaneously to distribute the pressure differential between the two, which may increase the service life of the elements. The upper stripper, whether of side door or conventional design, is usually mounted as usual. The lower stripper is mounted directly underneath. In this case the upper stripper is used as the primary packer. The lower stripper is not energized and kept in reserve. If the upper packer becomes worn, the lower can be energized to make the seal. The operation may continue or the upper packer replaced.

¹ A rubber-like synthetic polymer, as silicone rubber

ANNULAR PREVENTERS

On some jobs a small bore annular preventer is rigged up below the stripper(s) with a flow-cross and manual valve installed above the annular. The annular can be used as the “stripper” or, in other cases, used to provide flexibility to the current operation.

BOP STACKS

Although the stripper(s) provide the primary well control barrier, a second barrier is required for coiled tubing operations. Blowout preventers designed for coiled tubing units are available from several manufacturers. As the applications dictate, more BOPs may be added for enhanced safety, flexibility and operational requirements. These BOPs are available with 2 1/2” to 6 3/8” bores and with pressure ratings up to 15,000 psi in standard and H₂S trim.

THE QUAD STACK

The most common BOP stack used in coiled tubing operations is a compact series of four ram sets called a *quad stack* which is installed below the stripper assembly. The quad stack provides easy rig-up and a minimal vertical height.

Quad stack arrangement from top to bottom:

- Blind rams
- Cutter/shear rams
- Slip rams
- Pipe rams

The rams on the quad stack perform four functions, 1) sealing the open bore, 2) shearing the tubing, 3) supporting the sheared tubing and 4) sealing around pipe.

The *blind rams* are used to seal the wellbore off at the surface when well control is lost. The seal is made when the elements in the closed rams are compressed against each other. The tubing or other obstructions across the ram bonnets must be removed for the blind rams



Figure a-22: Quad ST aCk WITH boP below

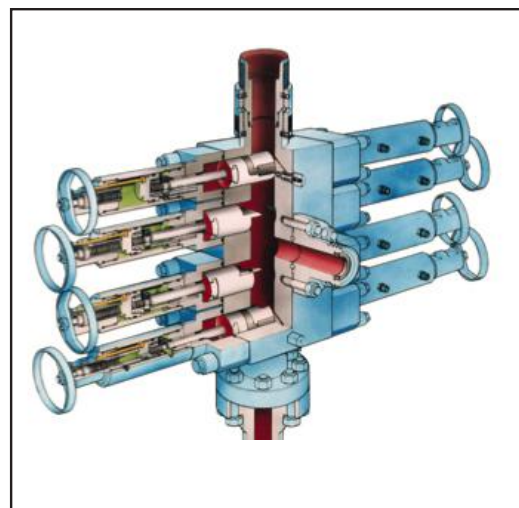


Figure a-23: raM rePlaCeMent in Quad ST aCk

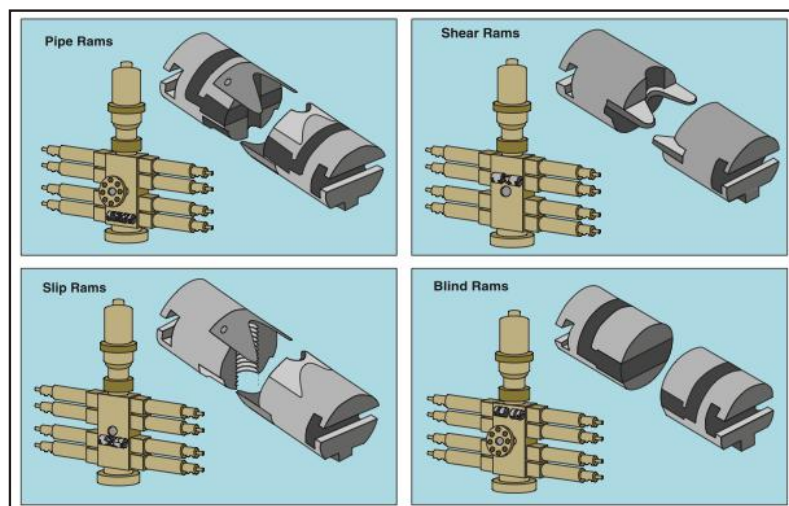


Figure a-24: PoSiTioning oF raM TyPeS WiTHin a Quad ST aCk

to work properly. It should be noted that the pressure seal on the blind ram assembly is designed to hold pressure only from below.

The tubing *cutter/shear rams* break, or otherwise shear the CT string if it gets stuck, or if it is necessary to cut the pipe and remove surface equipment from the well. As shearing blades are closed on the CT string, the forces imparted cause the tubing body to yield to the point of failure. Shear blades must be sized to the tubing in use and give a circumferential cut. If the cut is deformed in some way, it must be dressed to return to the proper geometry. Accessory hydraulic booster units or actuator units may be required, depending on tubing grade.

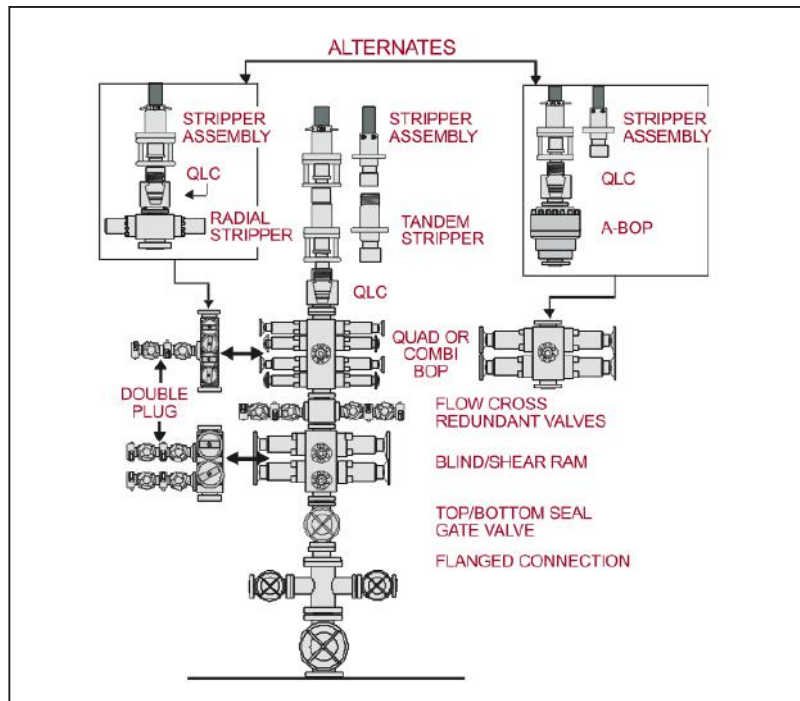


Figure a-25: High PreSSure boP oPTionS

The *slip rams* are equipped with bi-directional teeth that, when activated and closed, support the hanging weight of the pipe or, if wellbore forces are greater than the tubing weight, the bi-directional slip rams secure and prevent movement of the pipe, preventing it from being blown upward. The slip rams are equipped with guide sleeves which center the coiled tubing into the grooved recesses of the ram body as the slips are being closed.



Figure a-26: Slip ram inSerTS

The *pipe rams* are equipped with seals that are pre-formed to the specified OD of coiled tubing in service. When closed against the coiled tubing, pipe rams are used to isolate the wellbore annulus pressure below the rams. The pipe rams are also fitted with guide sleeves that center the coiled tubing into the recess as the rams are being closed. A kill line flange outlet is usually positioned directly below the shear rams and above the slip rams in the quad stack. A valve rated to maximum allowable working pressure (MAWP) of the BOP stack (usually 10,000 psi) is mounted onto the kill line flange. At least one additional through-bore, high pressure isolation valve is included from which a high pressure chicksan line is run to connect to the BOPs.



Figure a-27: PiPe raM WiTH guide

The kill line on the preventers is normally used to pump *into* a well. The flanged side outlet valve on the BOPs can be used to take returns or reverse-circulate fluid in an emergency. Taking returns through the kill line exposes

lower sets of rams and bonnets to solids or debris and is not recommended because it may adversely affect ram performance. When workover services require circulation of wellbore fluids to surface (spent acid, etc.), a separate flow-tee mounted directly below the Quad-ram BOP stack is recommended. The flow tee should be equipped with a high-pressure isolation valve rated to the same working pressure and NACE² classification as the Quad-ram stack. It is advisable to have BOPs installed below the circulating port to maintain control of the well in case the circulating port washes out.

The blind ram and pipe ram compartments on most preventer bodies are equipped with equalizing valves which, when activated, allow pressure to equalize within the ram body. This allows the differential pressure to equalize across the ram compartments prior to opening the rams. The union directly above the quad stack connects to the stripper assembly located on the bottom of the injector. The bottom connection on the quad stack may be a quick union or flange, depending on pressure and conditions.

Dual (combi) and even *triple ram* sets are sometimes installed below a quad stack for reasons of total stack height and/or weight. Blind/shear rams are often incorporated in one of the combi-unit's rams. A triple ram set is often combined with a single ram and spacer or a riser spool for running tools.

Conventional drilling/workover units use an independent hydraulic accumulator system to operate the BOPs. These systems store hydraulic fluid in a series of nitrogen pre-charged bottles. Most units use 3,000 psi systems and a bottle pre-charge pressure of 1,000 psi ($\pm 10\%$) which provides sufficient fluid to operate the preventers through a close/open/close cycle and still retain a minimum pressure of 1,200 psi.



Figure a-28: loWer kill line uSed For reTurnS

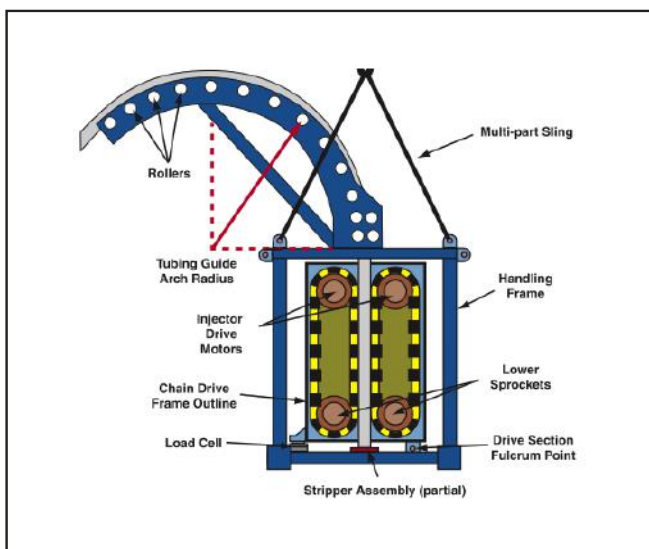


Figure a-29: baSe CoMPonenTS oF THE injeCT or aSSeMbly



Figure a-30: aCCuMula Tor SySTeM

The BOPs used by coiled tubing units are operated by a dedicated 3,000 psi hydraulic circuit; therefore they have no need for a fully independent accumulator system. However CT units do have several small (in comparison to drilling rigs) accumulator bottles that provide backup fluid to operate the BOPs in the event of a power failure. The nitrogen pre-charge pressure for the small CT bottles is usually maintained between 1,400 and 1,500 psi which provides sufficient power to meet the standard requirement of three complete close/open/close cycles of all ram components in use without requiring recharge fluids and pressure from the power drive unit.



Figure a-31: aCCuMula Tor SySTeM, TruCk MounTed



Figure a-32: leFT : MeCHaniCal dePTH CounTer, right



: vieW FroM inSide a Coiled Tubing uniT

SECTION 2: THE COILED TUBING STRING

MANUFACTURE

The manufacture of a coiled tubing string is a carefully controlled, multi-step process which begins with long ($\pm 3,500$ ft.) strips of steel cut to a width that will eventually form the circumference of the finished coil. The flat strips are then bias-welded³ end-to-end to form a continuous roll of sheet steel of specified length. After the welds have been cleaned and x-rayed, the flat coil is passed through a series of rollers, which work it into a tube. As the edges of the steel are pressed together, they are welded by a high frequency induction process. The now-formed tube is sized to outside diameter (OD) and roundness tolerances determined by the specifications. At various stages throughout the manufacturing processes, from flat steel to the finally formed tube, the CT is inspected and x-rayed and all inspections are documented to assure quality control. The tubing is precisely heated and cooled throughout the manufacturing process in order to achieve the desired ductility or other metallurgical results. When finished, the tubing is spooled onto a service reel or a transport drum and tested.

All manufactured spools of coiled tubing are given a unique identification number that is assigned at the time of their manufacture. Documentation for each spool of coiled tubing includes the OD of the tubing, the material grade, the wall thickness, the weld positions and the total length. Tractability of the coiled tubing product is maintained by the manufacturer throughout the entire manufacturing and testing process. The requirements of the purchaser often include tractability to the heat of steel.

Tapered strings of coiled tubing can be manufactured by changing the wall thickness of the tubing within the length of a spool while maintaining a constant outside diameter. This is done to increase the performance properties of the coiled tubing in selected sections while minimizing the total weight of the string.

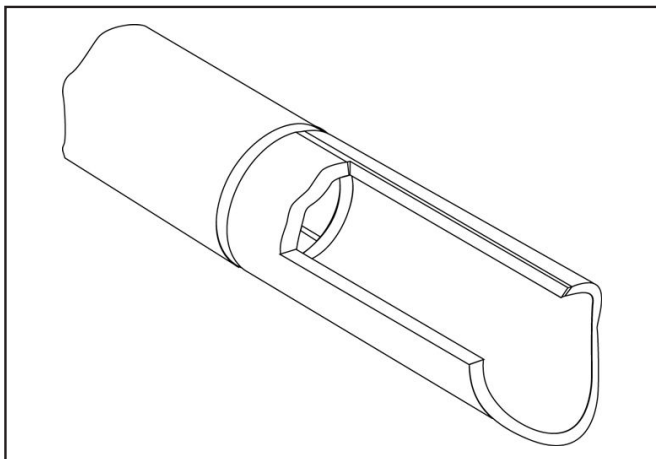


Figure a-33: buTT Weld

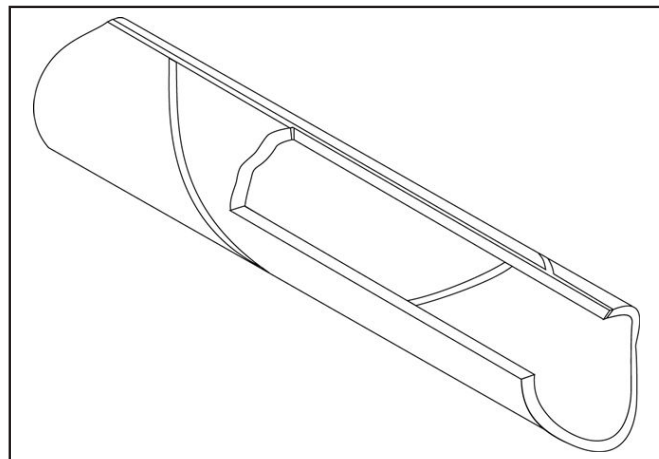


Figure a-34: bias Weld

³ Diagonally, across the width of the flat strip of steel.

Sometimes the CT manufacturing processes may require that a string be constructed by butt-welding sections of tube together. In this case, each butt-weld must be x-ray inspected to evaluate the quality of the weld. Note that the exterior surface of the weld is not dressed-off or disturbed in any way and may reduce the cycle life and yield strength several feet on either side of the weld.

WORKING LIFE OF COILED TUBING

Once put into service, the tubing stored on a service reel is deployed into the wellbore to the designated depth and then retrieved back onto the service reel for storage and transport to the next work location. A reel operations log should be kept on each reel. By documenting the length of tubing run, number of cycles, the type of job, where any damage was observed and the total feet run on the tubing, the tubing may be cut or taken out of service before failure on the job. If visible damage is noted, a de-rating factor of the overall tubing's strength should be applied. The working life of coiled tubing refers to the duration of service a continuous tubing string can deliver when subjected to the following effects which are discussed below:

- Bend cycle fatigue⁴
- Internal pressure loading
- Applied axial loading⁵
- Corrosion
- Mechanical damage

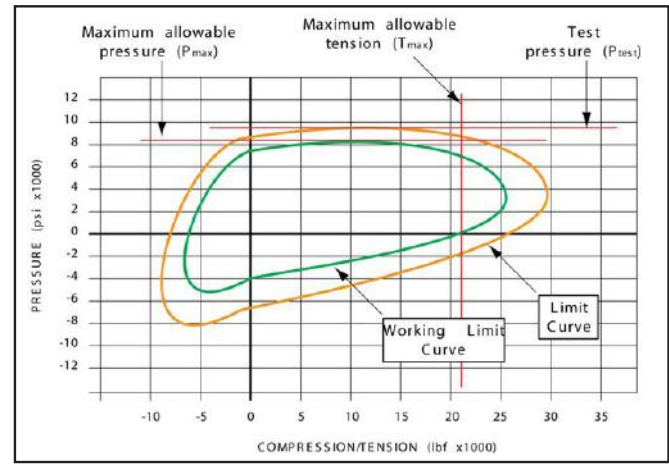


Figure a-35: Several Factors or Affects the Operational Limits of Coiled Tubing

All the effects listed above act on the coiled tubing to some degree during any CT service and each of them contributes to the eventual mechanical failure of the tubing. The decision as to when to retire a specific CT string is based on the current tubing condition plus a careful detailed analysis of its service history.

Many service operations impose compressive loads on a CT string as a result of the combined effects of wellhead pressure, the friction passing through the stripper and other related forces. If excessive compressive loads are imposed, pipe buckling at the surface can become a major concern. The buckling calculations used to determine buckling resistance for conventional jointed pipe cannot be used arbitrarily for CT. The forces required to induce buckling of coiled tubing depend upon the material characteristics of the tubing, tubing geometry (OD, wall thickness and ovality) and residual stresses within the tube. When the combination of bend-cycle fatigue and misalignment of axial forces are taken into account, the buckle resistance of coiled tubing must be de-rated relative to values calculated when using equations for conventional tubulars.

On operations in which minimal snubbing loads are anticipated, the unsupported tube length beneath the lowest gripper block and the top of the stripper is usually not an important concern. However, where large snubbing loads

⁴ The tendency of material to break under repeated cyclic loading at a stress considerably lower than the tensile strength indicated by static tests. Ref: A Dictionary for the Petroleum Industry (2nd ed.)

⁵ Pressure produced parallel to the CT when pushed against an obstruction or tight spot.

are anticipated, an anti-buckling guide tube should be incorporated into the injector mechanism in order to provide lateral support to the tube body. The guide can significantly increase the snub load limits of the tube. Compressive load analysis and assigning operational limits to the CT string are important components of coiled tubing well service design.

BEND CYCLE FATIGUE

Fatigue is considered the single major factor in determining the working life of coiled tubing. The deployment and retrieval of the continuous tubing string subjects the tubing to repeated bending and straightening events, referred to as *bend cycling*. The degree of strain imposed on the body of the tubing during the bend-cycling process is enormous; in many cases on the order of 2 to 3%. When the coiled tubing string is subjected to this type of fatigue cycling, stress/strain fluctuation failure may be adequately calculated using conventional multi-axial fatigue life computations. However, when the bend-cycling process is coupled with internal pressure loading, the prediction of fatigue life becomes difficult to calculate accurately. Numerous tests have confirmed that bend-cycling coiled tubing with internal pressure loading dramatically reduces the fatigue life of the pipe when compared to the cycle-life of unpressurized tubing. Essentially, there are no other applications outside of the coiled tubing industry involving steel alloys in which cyclic loading of this magnitude is intentionally imposed and still expected to survive the prescribed service life.

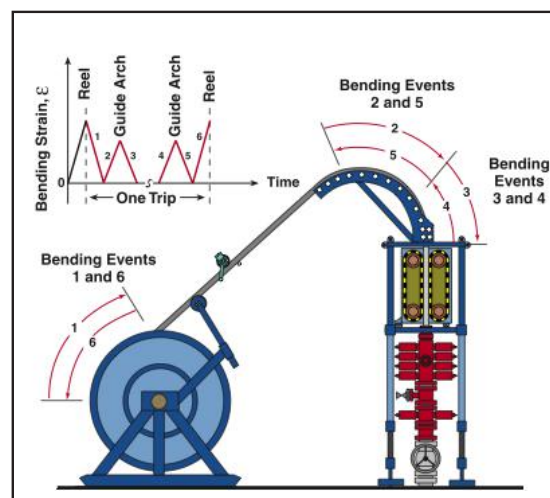


Figure a-36: bending events occurring during Coiled Tubing operation

Analyses of trends recorded from various coiled tubing fatigue tests suggest that bend-cycle events imposed on a given coiled tubing specimen with high internal pressure loading accumulate fatigue damage at a greater rate than bend-cycles imposed with low internal pressure loading. In addition, the magnitude of fatigue damage realized from a given bend-cycle event cannot be applied to working life predictions in any linear fashion. Evidence from a large volume of testing suggests that a given bend cycle load, applied later in the tube working life, causes greater fatigue damage than the equivalent bend-cycle load applied earlier in the working life of a tubing specimen. The diameter of coiled tubing tends to grow (balloon) when the tubing is subjected to plastic deformation due to bend-cycling with internal pressure loading.

DIAMETRICAL GROWTH

Even when internal pressure loading is well below the yield stress of the material, the tube body is subjected to hoop and radial stress, which causes the material to distort. This phenomenon is called diametral growth. The primary factors that influence *diametral growth* are the material properties of the tubing, the bend radius, the internal pressure loading and the coiled tubing geometry (OD and wall thickness).

The interaction with surface handling and pressure control equipment is a major concern for diametral growth. The injector gripper block loading on the coiled tubing has an impact on the tube geometry. The effect varies according to the magnitude of gripper block normal force and the block geometry, as well as the forces acting on the CT string.

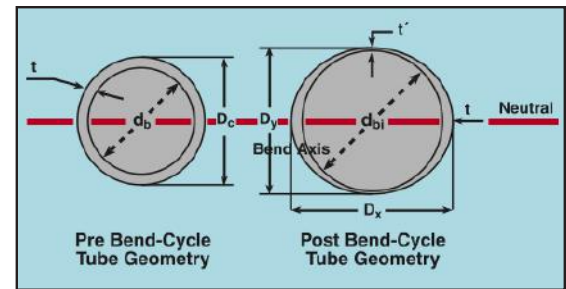


Figure a-37: geoMeTriC CHange To Tube diaMeTer
aS reSul T oF ovaliTy

Most conventional counter-rotating chain injectors have gripper blocks which are machined to fit the OD of the tubing in use. When the tubing experiences diametral growth, the increase in tube size creates a non-symmetrical loading condition. The normal force load is concentrated at the contact points on the edges of the gripper block. These focused stress concentrations induce damage to the tubing body, which results in additional tube deformation.

Diametral growth can cause damage to the tubing as it passes through the pressure control equipment. The stripper assembly contains brass bushings which prevent extrusion of the sealing elements. These bushings have an internal diameter (ID) which is slightly larger than the OD of the coiled tubing. If the actual coiled tubing diameter reaches or exceeds the internal diameter of the brass bushings, the coiled tubing will bind up within the bushings, resulting in damage to the surface of the tubing. If the coiled tubing can no longer pass through the stripper, it can damage the brass bushing. One consequence of diametral growth is the wall thickness of the tube is reduced somewhat. With the exception of thin-walled tubing, this does not have a significant effect on the overall working life of the tubing.

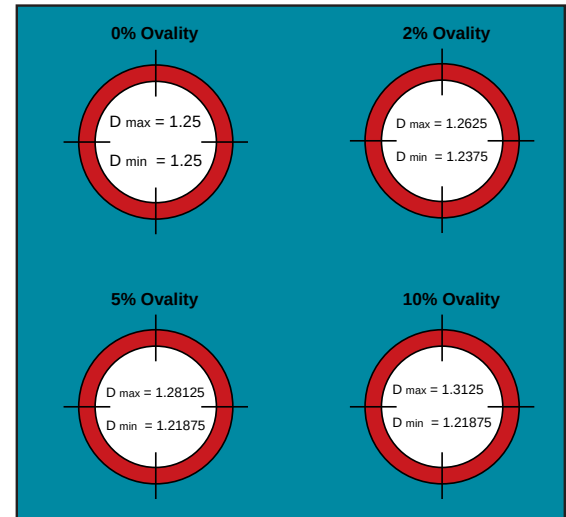


Figure a-38: exaMPleS oF geoMeTriC CHange To
Tube diaMeTer aS a reSul T oF ovaliTy Tubing
oPeRa TionS

With regard to diametral growth, bend-cycle fatigue testing has indicated:

- Diametral growth increases as internal pressure loading increases.
- The diametral growth of large diameter CT tends to be greater than that of smaller diameter coiled tubing.
- Coiled tubing with higher material yield strength is subject to less diametral growth than lower yield strength specimens.
- High internal pressures do not seriously limit the projected effective working life of CT when working through surface equipment tolerances that are designed for allowable diametral growth.

OVALITY

The cylindrical shape of coiled tubing tends to flatten into an ellipse, or oval shape, as the tubing is repeatedly deployed and retrieved over the gooseneck during normal operations. The term used to describe this change in shape is *ovality*. The oval shape becomes permanent and remains even when the tube returns to a straightened position.

Ovality significantly reduces the coiled tubing collapse pressure rating as compared to the collapse rating of the tubing when it was in its original round shape. Ovality may also adversely affect the pressure sealing capability as well as the interaction with gripping equipment. A commonly accepted practical limit for CT ovality is 5%.

DE-RATING COILED TUBING

It can be seen that accurately predicting the working life of the relatively thin-walled coiled tubing strings is a major industry goal for reasons of safety as well as economics. Three basic methods for downgrading the tubing service life have been used. Each method is briefly described below.

RUNNING FEET METHOD

The *Running Feet Method* entails recording the footage deployed on each individual job and adding it to the total accumulated footage on that particular coiled tubing string. A predetermined retirement life is developed by considering the total footage in light of variable factors such as the service environment, the type of service commonly performed and the local field history. Although simple to use, the Running Feet Method is not often used today.

The method has several serious limitations, some of which are listed below:

- The predetermined retirement life is based on experience with the same type of tubing performing the same type of service. No consideration is given to tubing degradation due to corrosive environments.
- The method focuses on the outside diameter of the coil. Wall thickness and metallurgical properties are not considered.
- The method provides no means of accounting for stresses imposed by variables such as internal pressure, changes in gooseneck or reel drum radii and no means of identifying weaker segments within the string.
- Data collected for a particular tubing string cannot be extrapolated for use by other strings of different diameters or other working conditions.

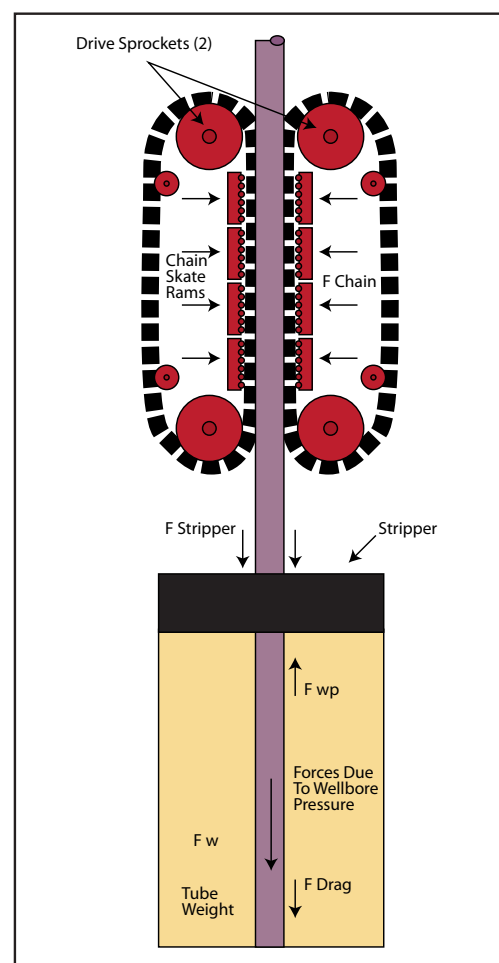


Figure a-39: From THE inject or inT o THE Well, Many ForCeS aCT on Coiled Tubing.

TRIP (EMPIRICAL) METHOD

The *Trip Method* was developed as an extension to the Running Feet Method and resulted in significant improvements in predicting the service life of coiled tubing. The method was developed by collecting data from numerous field tests and applying the data to previously projected tubing life models.

- The coiled tubing string is tested and data is collected in segments of the tubing. Then segments of the string which have accumulated more (or less) bending cycles are identified. Segments range from 100 to 500 feet. It can be seen that if shorter segments are chosen for data gathering, the accuracy of the bend cycle record is improved.
- Internal pressure loading is tracked and incorporated into the footage and bend cycle data.
- Data is collected from numerous tests using full service equipment (gooseneck, service reel injector, etc.).
- Analysis of data gathered during Trip Method tests has been used to identify trends so that curves could be constructed from which empirical data points were taken and incorporated into conventional fatigue life predictions. The Trip Method resulted in a great improvement over the Running Feet Method, but it does have limitations. The data for fatigue damage are generally different for each combination of coiled tubing material; that is, outside diameter, wall thickness and bending radius.
- Bend-cycle testing using full-scale equipment is required to obtain the fatigue data experimentally, which is expensive and time-consuming.
- The trip method does not incorporate tube body damage to the tubing as a result of well servicing operations (wear, interior/exterior corrosion, nicks, cuts or scarring).
- The test data obtained from bend-cycling machines will usually be at a constant internal pressure, whereas in the field, each section of the string has a different internal pressure at the point where bend-cycling occurs. The varying internal pressure loading at the point of bend-cycling requires a complicated recording and prediction procedure in order to provide a realistic working life prediction.

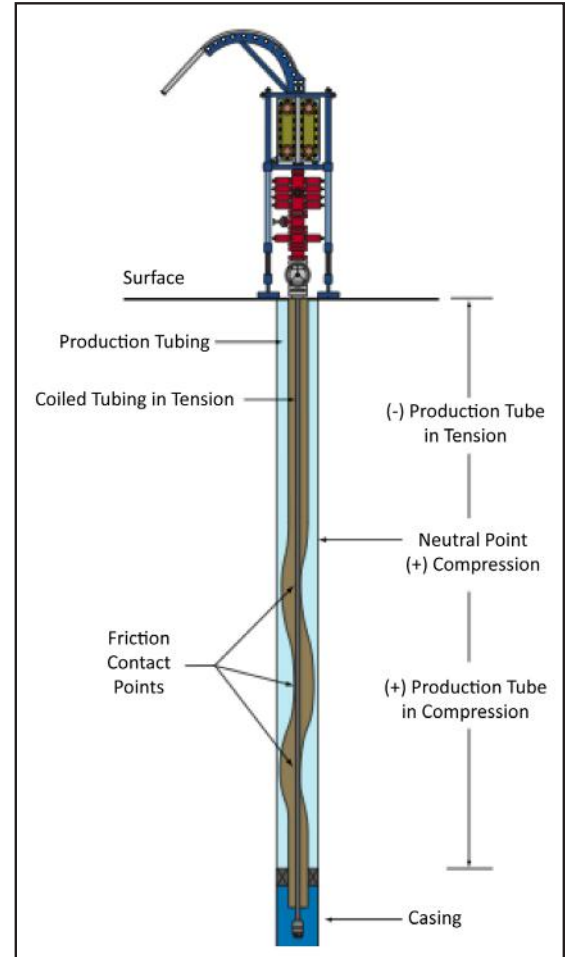


Figure a-40: Production Tubing May buckle due To Slack off Weight, Complicating The Coiled Tubing run.

THEORETICAL METHOD

The *Theoretical Method* for predicting tubing fatigue incorporates much the same approach as was developed in the Trip/Empirical method. Providing a theoretical prediction model based on the fundamental principles of fatigue with enhanced sensitivity placed on tube geometry, bending radii and tube material properties. However, the Theoretical Method does not incorporate tube body damage incurred as a result of field operations.

The theoretical modeling of fatigue involves use of plasticity algorithms and damage algorithms. The plasticity algorithm is used to estimate the instantaneous stress and strain condition of the coiled tube material for a specified bending radius and internal pressure loading. This requires input of the specific material properties. Although these methods are well-established, most laboratory testing is uni-axial, where the sample is loaded along a single axis, in contrast to coiled tubing loading, which is multi-axial.

The damage algorithm is used to quantify the reduction in working tube life (damage) caused by specific stress/strain conditions and ultimately add the damage for each bend-cycle in order to yield an overall value for fatigue life. The value of fatigue damage is usually expressed as a percentage of the predicted working life of a given tube and test condition.

Field operations are commonly performed with coiled tubing strings at internal pressures exceeding 10,000 psi. These services are considered to be job-specific and require specially designed heavy-wall coiled tubing strings. They result in early retirement of the string due to the dramatic effects of diametral growth. Since the internal pressure applied to the tubing will vary significantly over the service life of the pipe, accurate prediction of cycles-to-failure requires the use of sophisticated numerical models which rely on detailed onsite monitoring programs designed to evaluate all of the operating conditions of the pipe in service. Today's modern CT units monitor and feed fatigue data directly into complex computer software packages that are connected to the unit console within the control cabin. The advantages of using theoretical models include the greater accuracy of bend-cycle fatigue life prediction with the capability to predict fatigue life for variable loading conditions.

To summarize this discussion on coiled tubing fatigue, it can be said:

- The working life of the coiled tubing can be extended by increasing the bend radii of the tubing guide arch and reel core for a specified tube diameter size. The working life of a specified size of coiled tubing can be increased by selecting a tube with a thicker wall.
- The working life of the coiled tubing can be extended by increasing the material yield strength of the tube.
- As the OD size of the coiled tubing increases, the working life of the string decreases.

SECTION 3: PROCEDURES

PRE-JOB PLANNING

Coiled tubing units are designed to perform a wide variety of workover/well intervention operations on live wells and it is crucial that a detailed plan be developed prior to each job. The overall job plan actually consists of several integrated sub-plans that address the main objectives of the job as well as safety issues, including well control contingency planning. Planning starts when the operator contacts the CT contractor and briefly outlines the general requirements. At that time the contractor begins to gather the specific data that engineers and supervisors will use to develop a final job plan. The list below contains some of the more important information used when developing a complete operational plan.

- Location details, including information about adjacent wells and environmental concerns.
- Safe equipment handling issues, especially in transport, off-loading, rigging up and down.
- A general history of the object well, including the reservoir characteristics and production history.
- Anticipated formation pressure.
- The primary objectives of the job.
- Size and type of all wellhead connections.
- Details of surface controlled safety valves in place (ESD).
- Special hazards such as toxic or corrosive fluids (H₂S, CO₂, etc.).
- History of well problems such as corrosion, paraffin, etc.
- Type and dimensions of tools used in the completion.
- Detailed data concerning the production string, including de-rated strength values.
- Well profile including MD and TVD, as well as pertinent directional data.
- Perforation depths.
- Completion fluid characteristics and density.
- Surface pressures (flowing and static).
- Site evacuation plans.
- Pressure testing practices.
- Well control contingencies.

GENERAL RIG-UP PROCEDURES

Rig-up procedures will vary depending on what type of operation is to be performed. While rigging up, care must be taken not to damage BOP components, rings and ring grooves. All fittings and couplings must be free of trash and dirt before making them up. All lines that are to be subjected to pressure must be pressure-rated (Co-flex or steel lines, not rubber hoses). Flanged connections with targeted turns should always be used.

1. Check and record pressures on each casing and tubing string.
2. Close all valves on the Xmas tree. Count and label the number of turns required to close each valve on the tree and flow lines. Bleed pressure off below the crown (swab) valve.
3. Inspect the rings and grooves on the BOPs. Rings should be used one time only, then discarded. Install rings only in clean, dry grooves. The rig-up to the Xmas tree should be flange to flange, or flange to Bowen type connection. Threaded connections between the BOPs and tree should not be used.
4. Break flange fittings slowly and check for trapped pressure.
5. Make up the riser or spacer spools and the BOPs to the wellhead.
6. Secure and stabilize the BOP stack with a minimum of three chains or cable lines. If an excessively long lubricator is used, secure it with cables or lines every 35 feet.
7. Function-test the stack.
8. Slowly and carefully pick up the injector/extractor head assembly.
9. Check all connections and lines.
10. Rig-up the tool assembly on the coiled tubing.
11. Make up the injector/extractor assembly to the BOP assembly, stabilize it and secure it in place with lines and/or crane or the injector base.

CONTROL CABIN CHECKLIST

1. All control levers should be in the neutral, inactive or off positions on each console (control and auxiliary panel).
2. Start the power pack.
3. Check each gauge to insure the hydraulic system is properly pressurized.
4. Test hydraulic system to its full working pressure. Change out any bad control lines, hoses, connections and gauges.
5. Function test all controls for “hydraulic creep.”
6. Regulate the power pack to the proper speed/pressure for entering the well.
7. Regulate the pressure to the BOP stack.
8. Measure and record the distance from the top of the upper well or tubing valve (masters or full opening safety valve) to each component of the stack and injector.

SITE CHECKLIST

1. Rig-up the pump lines, standpipe lines, kelly hose, choke line, returns line, bleed-off lines, kill lines, etc. Secure all lines.
2. Locate and inspect all fire extinguisher equipment. Firefighting equipment should be easily accessible, in plain view and known to all personnel.
3. Test the communications network. Review alternate communication systems, such as hand signals.
4. Police the area for non-essential equipment. Keep walkways free and clear.
5. Review company and contractor safety requirements and procedures, including clothing, accessories and personal safety devices.
6. Evacuate non-essential personnel from the area.
7. Test the BOPs.

BOP TEST PROCEDURES

Before starting a job, the BOP stack must be tested to help ensure that it will hold up to the maximum anticipated pressures from the job. BOPs are usually checked out and tested at the maintenance facility of the contractor prior to shipment to the job site. Good practices, as well as most local regulatory agencies, require that all pressure control equipment be tested before a job begins, according to the following standards:

- The onsite tests include function-testing the preventers, followed by both low and high pressure tests.
- The low pressure test must be performed first and should be conducted at pressures between 200 and 300 psi.
- The high pressure test should be the lesser of the maximum expected surface pressure, minimum burst pressure of the well's tubing or the pressure rating of the BOP stack and associated well control equipment.
- The operating company may dictate test pressure.
- All pressure tests should be held for a sufficient period of time to demonstrate that the component is effectively holding pressure.
- The tests must be conducted using a fluid that will not cause pollution or harm personnel if a leak develops (i.e., water). Other fluids may be used if pollution or operator restrictions allow.
- The results of each individual test must be documented accurately.

Specifics of BOP testing vary with the type and number of components that are to be tested. The following procedure assumes a standard CT arrangement of: a stripper assembly, a quad stack (from the top: blind, cutter/shear, slip and pipe rams, an outlet (kill line) between rams #2 and #3, an outlet spool (return line) below ram #4 and a valve (lubricator or full opening safety valve) or kill spool below the outlet spool.



Figure a-41: boP on job SiTe

1. After installing and functioning the equipment, the indicator pins (if equipped) should be visually inspected.
2. Open all valves and rams.
3. Rig-up to pump into a wing valve (on Xmas tree) or pump in line (tubing or drillpipe).
4. Close the outer kill line (outer BOP outlet) valve.
5. Fill the stack with test fluid.
6. Close the blind rams.
7. Apply the appropriate pressures (low, then high). Record the pressures and bleed the pressure off.
8. Open the outer kill line valve.
9. Close the lubricator or full opening safety valve, then apply pressures as in step 7. Record the pressures from the kill spool and bleed off.
10. Open the blind rams.
11. Close the inner kill line valve and the outer (pump in or returns) valve on the outlet spool.
12. Make up a bottomhole assembly and run in to a point just above the lubricator/full opening safety valve.

13. Fill the stack with test fluid then close the stripper. Apply the appropriate pressures. Record pressures and bleed pressure off.
14. Close the inner outlet spool valve. Close the pipe rams. Open the lubricator or full opening safety valve (atmospheric pressure is now above pipe ram.) Open the stripper. Apply the appropriate pressures. Record pressures and bleed off.

Once the BOP test is complete, preparations can be made for injecting the coiled tubing into the well. Ensure that all inner and outer valves are in the proper position, close the stripper, pressure up to equalize to the shut in pressure of the well, then open the valve to the well.

ENTERING A LIVE WELL

One of the primary advantages of a coiled tubing unit is its ability to circulate as the tubing is run into or out of a live well. The relatively small inner diameter (ID) of coiled tubing results in much lower circulation rates than conventional drilling/workover rigs. Consequently friction pressure is correspondingly high.

The majority of tools used in CT work have been adapted from other well intervention applications and some specific tools have been developed exclusively for coiled tubing. Examples are rotary drills, impact drills and washover tools. The discussion below describes a typical coiled tubing work string and methods for injecting the string into a live well. It should be noted that due to the broad scope of coiled tubing work, the discussion is general and no attempt is made to cover the numerous alternate possibilities.

A connector or adapter is attached to the end of the coiled tubing, which serves as the base for attaching the various tools that will be run. Two check valves (BPVs), one above the other (sometimes a tandem unit), are attached to the connector. There are various BPV designs available: flappers, ball-and-spring mechanisms, etc. Ultimately, the choice depends on the particular operation, which can range from simply cleaning out sand to electric logging.

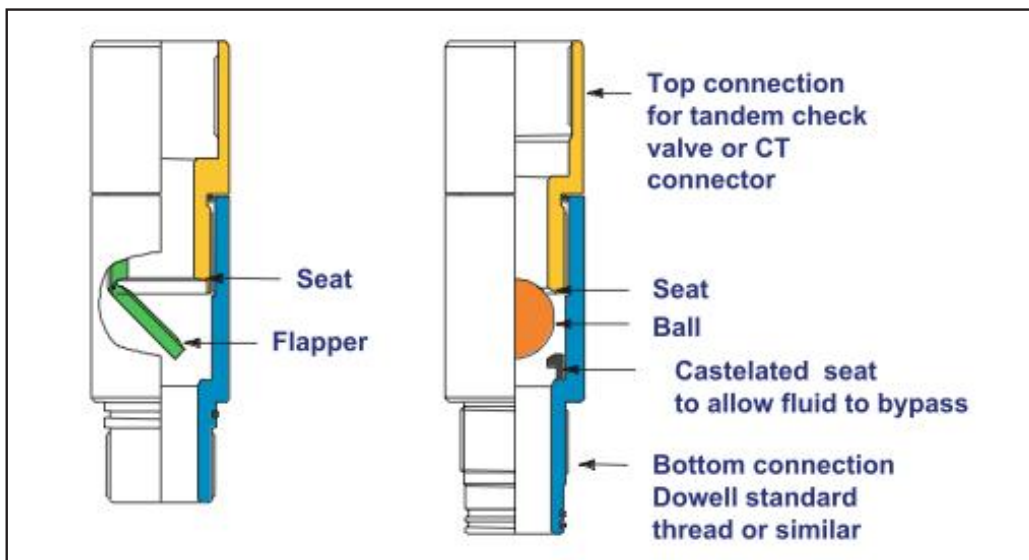


Figure a-42: CHecK valveS or baCkPreSSure valveS

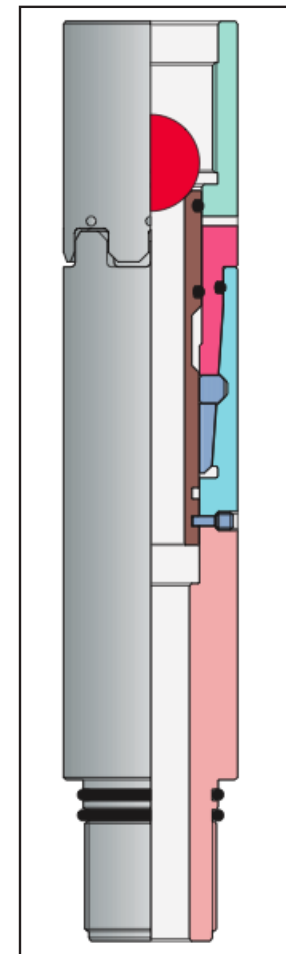


Figure a-43: releaSe joint

A release joint is connected immediately below the BPVs. As the name implies, the function of the release joint is to disconnect from the bottomhole assembly in the event it becomes stuck in the well. The lower portion of the release joint is designed in such a way that it can be reattached when attempting to recover the tool string if it becomes stuck. Depending on the type of release joint run, the toolstring may be released by shear force, pump pressure, pumping a ball or a combination of these forces. The majority of release joints for conventional CT applications are controlled and operated by pulling tension or by circulating pressure. A circulating or bypass port is often included in the release joint to allow flow into the annulus in case the flow rate of pumped fluid exceeds the rate necessary to operate downhole tools.

GENERAL JOB REQUIREMENTS

Depending on the type of job, job location, pressure and operator requirements, equipment and procedures to perform, the operation will vary. The basics for any operation are the coiled tubing unit and some type of pump. From this point equipment options include: return tanks with adjustable chokes, mixing tanks, blending tanks, cementing units, hot oil and treatment units, nitrogen pumping units and nitrogen tanks, downhole tools, fishing tools and wireline units. In many operations, circulating friction is a main consideration. Overcoming friction in the small ID of coiled tubing at pump rates necessary to effectively perform the job can dictate that the coiled tubing be cut or sized for the job. For example, on a 5,000 foot well, 5,800 to 6,000 feet of tubing may be specified by the operator.

Another area of concern is the anticipated or present wellhead pressure. In general, 10,000 psi is the maximum wellhead pressure that many coiled tubing units are rated for; however, there have been coiled tubing jobs performed at considerably higher pressures. Coiled tubing conveyed perforating guns and gas-lift work is routinely and safely done against pressure greater than 10,000 psi. Each well must be evaluated on a case-by-case basis.

It is the rate at which coiled tubing can be injected and extracted that gives coiled tubing its greatest economical advantage over other types of well servicing units. The tubing is usually run slowly (30 to 60 ft/min) on its first run into a well. The injection rate is often increased on successive runs, depending on the well status and job progress.

TOOL INJECTION TECHNIQUES

The ideal condition to lower a tool string into a well is when the well is static or dead. In cases where there is a bridge or obstruction in the well, or in cases where the well is incapable of flowing, it may be possible to lower the string directly into the well, but the safest course of action would be to install the BOPs first, then lower the tool string. Although these wells are not flowing, they are dormant and have a potential to flow. They should be treated as though pressure or gas could vent at any time. From the time the crown valve is removed from the tree, until the BOP stack is installed, the personnel and equipment are vulnerable.

There are several ways to inject tools or a tool string against well pressure. Depending on the circumstances, the choice as to which method to use is usually limited. Each well must be judged on its own and the steps followed

to inject the tubing depend on the specific situation and equipment at hand. Most times the tool string will not pass through the stripper. One method used to insert the tool string into a live well is to have a wireline unit set a plug inside the tubing. If the plug can be set below the depth required for the work to be done, then pressure in the tubing can be bled off and the tool string run in.

A spacer spool can be used if the tool string is relatively short. In this case an extra BOP would be necessary. The crown or master valves on the tree are closed and then the tool string is run into the spacer spool until it is free and clear of the pipe ram in the BOP stack. The Xmas tree valves are then opened slowly and the tool string run in.



Figure a-44: a MaST TyPe Coiled Tubing unit

When the tool string is of moderate length, a lubricator with a riser pipe may be used. Special support arrangements have to be made in such a rig-up since the injector would be installed above the lubricator. The tool string can be made up and lowered into the lubricator, after which the injector is installed.

In cases where a relatively long tool string must be run into wells that are equipped with a surface controlled subsurface safety valve (SCSSV), the SCSSV may be closed, the pressure above it bled off, then the tool string run and the injector is installed.

SAMPLE PROCEDURE FOR INJECTING CT INTO A WELL

Procedures for tripping in and out of the well vary according to the type of operation being performed. The procedures listed below represent common practice for the majority of operations when the wellbore is full of fluid.

1. After the unit is rigged up and the BOPs tested, the tool string loaded in the riser/lubricator and the injector installed and secured, the unit is ready to run into the well.
2. Check to ensure coiled tubing is centered in the stripper.
3. Check buckling and buoyancy calculations, then set the main hydraulic pressure dump valve to 80% or less of the tensile strength of tubing.
4. Set the injection hydraulic pressure so that no more than the string weight can be set down.
5. Bring the power source on line and up to the required speed, checking for correct pressures and for leaks.
6. Apply enough pressure on the backup skates (inside chain tension) to hold the tubing in place.
7. Take the slack out of the chains by pressuring up on the outside chain tensioners.
8. Start pumping in order to load the tubing and establish returns.
9. Apply pressure to the stripper ($\pm 1,000$ psi).

10. If possible, pressure the BOP stack to the well the pressure and check to ensure that the tubing will be held in place against well pressure. Close the choke and wing valves on the Xmas tree.
11. Slowly open the master valves (lower first, then upper) or full opening safety valve, depending on the operation.
12. Place the injector valve in the "IN" position.
13. Adjust the stripper pressure so that the life of the stripper element is maximized, while at the same time a good seal is maintained.
14. Open the return line and establish circulation.
15. Run into the well slowly, increasing the injection speed to ± 60 ft/min while monitoring the weight and depth indicators.
16. Run the tubing in to about 200/300 feet, or just above the surface controlled subsurface safety valve (SCSSV, and stop.
17. Pick up the tubing in order to make sure the unit is functioning in the pipe out mode.
18. Begin running into the well at a safe and efficient rate. The rate will depend on the unit equipment, well conditions, the specific operation and the experience of the operator. Injection/extraction speed should be slowed when approaching any downhole restrictions or tools. If the tubing passes through a downhole tool or nipple, the pickup weight should be carefully checked.
19. When approximately 1,000 ft of tubing has been run in, pause and check the pick-up weight and set the weight indicator to the correct reading by comparing the actual weight against the calculated weight of the tubing at that depth.
20. Continue running into the well, pausing intermittently to verify the weight of the string and to adjust the skate pressure as necessary to prevent the tubing from slipping.

PULLING OUT OF A WELL

Once the job has been completed, the coiled tubing (in most cases) will be withdrawn from the well.

A general procedural checklist follows:

1. Lower hydraulic pressure to the injector motors to ± 400 psi.
2. Switch the injector IN/OUT valve to the OUT position.
3. Increase the reel tension as necessary to ensure that the tubing will spool efficiently onto the reel.
4. The majority of surface tubing failures occur when removing the tubing from a well; therefore, the CT should be pulled as smoothly as possible to minimize potential damage.
5. Monitor the weight indicator constantly to avoid exceeding the maximum tensile strength of the tubing.
6. Adjust the stripper pressure so as to wipe the tubing dry as it is pulled from the well.
7. Assume that the depth counter may be incorrect due to stretch. The string should be pulled carefully at a reduced rate as the end of the tubing approaches the surface.
8. When the end of the tubing nears the surface, reduce the skate pressure so that the stripper will hold the tubing as it enters the BOP stack, thus preventing it from being pulled into the injector.
9. Continue to pull the tubing until the end is just below the injector head.
10. Close the master valve on the tree (or full opening safety valve). Note: Long tool strings must be lubricated out. When closing the master valve, count the number of turns to ensure it is fully closed.
11. Bleed off the pressure trapped in the BOP stack.

RIG-DOWN CHECKLIST

Once the operation has been performed, the unit can be rigged down.

Note: There may be pressure trapped in the stack, between valves or in manifold.

1. If nitrogen has been used and the nitrogen unit is present, blow or displace the tubing with the tool string in the stack to minimize the transport weight.
2. Check to ensure that no pressure is trapped in the stack or between valves. Open the choke line, then open all stack valves and manifold lines.
3. Open the stripper.
4. Remove the tubing and spool it onto the reel. Secure the tubing and reel.
5. Rig-up the crane or lifting device to injector head. Remove and secure the injector/extractor.
6. Remove and secure the BOPs from wellhead.
7. Install the cap of the Xmas tree.
8. Rig down all equipment and prepare it for transport.

SECTION 4: COMMON COILED TUBING OPERATIONS

A detailed discussion of all the varied operations that can be performed by coiled tubing is beyond the scope of this text. General outlines of some of the most frequent CT operations are discussed below.

WASHING, CLEANING, CLEARING TUBING

Coiled tubing units are commonly used to clear or clean out production tubing that has been blocked due to accumulations of sand, scale or other debris. Paraffin and/or asphalts, which are contained in formation oil, often cause problems as they solidify in production tubing due to temperature changes. In these cases coiled tubing may be used to pump paraffin-dissolving solvents into producing oil wells.

ACIDIZING

Coiled tubing units are often used for acidizing or other selective zone chemical treatments. Although extensive work with acid will shorten the life of coiled tubing strings. Such work is carefully tracked nowadays so that the coil life can be de-rated with considerable accuracy. Depending on specific operations, acid can be applied in a variety of ways, including using foam, or sometimes nitrogen, to carry the chemicals to the zones.

Treatment zones are usually isolated with packers, either permanent or temporary packers, that can be set with coiled tubing. The formation pressure must be known accurately because if too much pressure is applied to the wellbore, large, deep fractures can occur, and the acid can bypass the intended zone. It is difficult to accurately determine the appropriate injection rate and maximum pumping pressure without using sophisticated computer software. After pumping the acid, the tubing should be completely flushed with the working fluid of the well. Once the tubing string is filled, it should be run to TD and the entire wellbore displaced. Returns are taken through a corrosion-resistant flow tee. Returns should *not* be routed through outlets on the quad stack.

FRACTURING

Formation fracturing with coiled tubing is most often done in short reservoir intervals. Although the small diameter tubing may limit pumping rates, this deficiency (as compared to conventional rigs) is overcome by the efficiency of which the coiled tubing can be deployed over several intervals in a relatively short time.

PERFORATING

Coiled tubing perforating techniques were developed to convey long, heavy tool strings into wells in which traditional wireline was not practical. Coiled tubing is used effectively in long-reach or highly deviated wells, or to convey a very long string of perforating tools.

SAND CONSOLIDATION (GRAVEL PACKING)

When running a long string of gravel pack screens or a slotted liner, a serious well control problem can develop because the check valves normally at the bottom of the CT provide no protection when a liner connection is made up at the surface. Wellbore pressure feeds directly up the string, making it virtually impossible to connect a liner joint or a screen section on a live well.

Even if the well has been previously killed, the personnel remain somewhat vulnerable to taking an influx while the slotted liner or screen sections are being made up on the end of a CT bottomhole assembly. Most operators are willing to accept this small level of risk after carefully ensuring that the well is dead before passing slotted liners or screens through the BOPs.

UNLOADING WELLS AND INITIATING PRODUCTION

In this process coiled tubing is run to a desired depth and nitrogen or lightweight foam is injected down the coiled tubing and back through the annular space of the production tubing, resulting in a reduction of hydrostatic pressure imposed on the formation to be produced, which allows the well to flow. Often several volume displacements are necessary for this to happen. The same principles are used to provide a pressure differential when perforating underbalanced.

CEMENTING AND SQUEEZING

Coiled tubing is used for several different types of remedial cement jobs. For instance:

- Squeezing a channel in a previously cemented zone
- Setting a kickoff plug for directional drilling
- Setting plugs used to abandon production zones
- Setting plugs to isolate production zones

Although cementing through coiled tubing is a common operation in certain areas, each job must be carefully planned so that the designed cement slurry allows sufficient thickening time, plus a safety margin, to complete the operation. The relatively small diameter tubing causes two important concerns that do not usually apply to conventional units that use larger pipe: 1) pumping rates are slow and the slurry must be retarded, and 2) high circulating friction can actually cause water to be squeezed out of the slurry as it is pumped. These effects can cause the cement to flash or harden, prematurely.

FISHING AND RUNNING TOOLS

There are two primary advantages of fishing with coiled tubing as compared to conventional wireline: 1) CT units have the ability to circulate while the fishing operation is in progress, and 2) the tensile strength of CT is much stronger than conventional wireline. Sand deposits and debris can be washed off the fishing neck. Circulating can also operate and power vibrating jars or impact hammers to apply relatively high upward impact forces on the fish without creating high stresses on the CT string.

TUBING CONVEYED LOGGING

Most conventional electric wireline work depends on gravity to pull the tools down into a well. However, gravity alone cannot pull tools to the desired depth in highly deviated (greater than $\pm 65^\circ$) wells. If the wireline and tools are conveyed using conventional tubing, it is difficult to slide the light tubing in wells that are deviated more than 26° . Since coiled tubing can be hydraulically injected into a well with great force, it has proven to be an extremely effective means of running logging and perforating tools into high angle wells.

The electric wireline can be inserted into the tubing in a number of ways. One method entails running the tubing into a test well of appropriate depth, then dropping the electric line down into the tubing and allowing it to fall due to gravity. Another method is to inject the wireline into a reel by using a special cyclone-type injection machine. It is also possible to purchase tubing that has been manufactured with the electric line inside. Regardless of the method chosen, excess wireline must be used because calculations have demonstrated that when the tubing is wound onto a reel, wireline length is approximately 1% longer than the length of the tubing due to the tubing wall thickness and the number of wraps on the reel.

A grapnel connector is used to connect the tubing to the tool string. A cable clamp sub assembly attaches the electric line cable to the upper tool string. This assembly allows circulation to the lower tool string. A swivel sub should be made up as part of the assembly. Finally, a barrier-type bulkhead adapter sub assembly seals against pressure from the tubing and the well. This is done to provide space for the conductor to pass. A rope socket attaches to the wireline heads. The spindle hub on the tubing reel is provided with the wireline.

When running tubing conveyed wireline, the length from the stripper to the blind ram length must be sufficient to cover the entire tool string that is to be used. This may require a long riser (60 feet or more) which complicates stabilizing the injector on top of the riser. An alternate method is to use a wireline unit and lubricator. The lubricator is installed on top of the coiled tubing stack, and then the tool string is run and hung off in the quad stack. In this case the end of the tool string is equipped with a deployment bar so that the pipe and slip rams will close, grip and form a seal. After the pipe and slip rams are closed, then the pressure in the lubricator can be released and the lubricator removed. The coiled tubing injector, with a short riser, is swung over the BOPs and then the coiled tubing is made up to the deployment bar. The riser/injector assembly is made up, the pressure equalized and the tubing deployed. The process is reversed when removing the tool string.

The cable clamp is designed to be weaker than the electric wireline in case the tubing becomes stuck. If tubing does become stuck, first the wireline is retrieved, followed by the tubing. The tubing should be reverse-circulated after two or three jobs, or after prolonged circulation, so the correct amount of wireline slack is maintained throughout the string. If this is not done on a regular basis, the necessary slack in the wireline will not be maintained, and the cable will pull out of the cable clamp at the bottom of the tubing.

SECTION 5: COMPLICATIONS

POWER PACK FAILURE

If the power pack should fail, the injector, the BOPs and the service reel will cease to function. The motor brake in the injector will stop and hold the tubing in place.

The following actions are required:

- Manually close and lock the slip rams and then the pipe rams.
- Chain the service reel to prevent the tubing from unspooling.
- Repair or replace the power pack (check that the BOP accumulators are fully charged before changing over).
- Equalize the pressure across the pipe rams; open the slip and pipe rams.
- Pick up the tubing and inspect the area around which the slip rams were set.

COILED TUBING COLLAPSE

Collapse of CT is the flattening of the tube due to the application of differential pressure (external to internal), with or without an axial tensile load. Collapsed CT inside the wellbore will not cause wellbore effluents to be released to the atmosphere; however, if the collapsed portion of the string is positioned across BOP stack or stripper, the change in tube body geometry will affect the performance of the pipe and slip rams. Usually a contingency plan is developed to deal with potential collapse problems. A method used to predict the width of a plastically-collapsed tube is shown in the following equation:

$$W_{COL} = .95 \times [D + .5708 \times D \times (1 - 2t/D)]$$

Where:

W_{COL} = is the predicted collapse width of coiled tube body (inches)

D = is the outside diameter of coiled tube body (inches)

t = is the wall thickness of coiled tube body (inches)

The predicted collapse width increases for a given CT string OD size when the wall thickness decreases. The following table illustrates examples of collapse width predictions and minimum stack bore sizes.

Example:

COLLAPSE WIDTH PREDICTIONS AND MINIMUM STACK BORE SIZE FOR CT

CT DIMENSIONS (INS.)	D/T RATIO	PREDICTED COLLAPSE WIDTH	MINIMUM BORE SIZE (BOP)
1.25 OD x 0.087 wall	14.4	1.771	2-9/16
1.5 OD x 0.095 wall	15.8	2.135	2-9/16
1.75 OD x 0.0109 wall	16.1	2.493	2-9/16
2.0 OD x 0.125 wall	16.0	2.849	3-1/16
2.375 OD x 0.145	16.4	3.387	4-1/16
2.875 OD x 0.156	18.4	4.121	5-1/8
3.5 OD x 0.203	17.2	5.003	5-1/8

RUNAWAY TUBING (DOWNHOLE)

A runaway condition can develop if the gripper blocks become fouled, or if there is too much weight and downward momentum. The tubing may pull through the chains even though the hydraulic pressure is shut off and the motor's brakes are engaged. Steps that can be taken to slow and stop pipe movement include increasing the traction pressure, increasing the stripper pressure to maximum and, if necessary, applying emergency traction pressure. Depending on company policy, applying reel brakes and/or closing slip rams may also be options. However, this action could cause the tubing to fail. The gripper blocks should be cleaned and the skate pressure adjusted before opening the slip rams.



Figure a-45: Use of a Crane is Integral To MoST Coiled Tubing Operation.

TUBING RUNAWAY (EJECTED)

When working against high wellhead pressure with little tubing in the well, it is possible that the upward forces are greater than the weight of the string. If the injector chains should fail to grip the tubing securely, the string will start to accelerate out of the well.

Suggested actions include:

- Close the slip rams.
- When the tubing stops, close the pipe rams.
- Evaluate the now-stable situation and determine the reason the injector control was lost.

REEL SKIDDING TO WELLHEAD

If the reel is not properly secured, or if it breaks loose from its binding for some reason, it may start to pull towards the wellhead. The commonly recommended procedure is to stop the injector and close the slip rams. Then let out enough excess tubing to skid the reel back to its proper position and secure it.

SIZE (INCHES)	CROSS SECTIONAL	FREE POINT
OD X WALL THICKNESS	AREA (SQ IN)	CONSTANT
1.250 x 0.087	0.304	760.0
X 0.095	0.328	820.0
X 0.102	0.351	877.5
X 0.109	0.374	935.0
X 0.125	0.420	1,050.0
X 0.134	0.451	1,127.5
X 0.156	0.512	1,280.0
X 0.095	0.399	1,997.5
X 0.102	0.428	1,070.0
X 0.109	0.456	1,140.0
X 0.125	0.512	1,280.0
X 0.134	0.552	1,380.0
X 0.156	0.629	1,572.5
1.750 x 0.109	0.538	1,345.0
X 0.125	0.605	1,512.5
X 0.134	0.652	1,630.0
X 0.156	0.745	1,862.5
X 0.175	0.831	2,077.5
2.000 x 0.109	0.619	1,547.5
X 0.125	0.698	1,745.0
X 0.134	0.753	1,882.5
X 0.156	0.861	2,152.5
X 0.175	0.962	2,405.0
2.375 x 0.125	0.837	2,092.5
X 0.134	0.904	2,260.0
X 0.156	1.035	2,587.5
X 0.175	1.158	2,895.5
X 0.190	1.241	3,102.5

Figure a-46: exCerPT From Coiled Tubing STreTCH T able

STUCK TUBING

The most common cause of stuck coiled tubing occurs when the tubing hangs up on something downhole. Sometimes, in a highly deviated or crooked wellbore, the friction is too much to overcome. There are several techniques that can be tried if circulation is possible.

1. Friction-reducing fluid additives can be pumped throughout the well.
2. A pump cylinder can be crippled, causing abrupt pressure changes, thereby jarring the tubing.
3. Heavier (denser) fluid can be pumped throughout the well to increase the buoyant effect on the string.
4. Working the pipe may help, but special attention must be paid to tensile loading to avoid parting the string.

If it is not possible to circulate, carefully working the tubing to its minimum yield strength is the only option but if the free point can be determined, it will assist in the decision-making process. The free point is usually determined by wireline, but it may also be estimated by carefully pulling up on the string and measuring the pipe stretch. This technique requires pipe stretch tables from which a numerical constant is derived. The constant is then applied to the formula below.

$$L = \Delta L C_{FPC} \div FD$$

Where:

L = Minimum length of free pipe (ft)

ΔL = Stretch (ins)

C_{FPC} = Free point constant

FD = Pull force difference (1,000 lbs)

As an example, suppose a 10,000 foot string of 1.25-inch OD, 0.087-inch wall of coiled tubing were stuck.

1. The operator then pulls at least 500 lbs over the hanging weight of the tubing and places a reference mark on the tubing.
2. The pull is then increased in increments of 1,000 lbs over the original tubing weight. Assume 5,000 lbs.
3. Determine the pull force difference between the overpull weight and the original weight, and measure the stretch in inches. Assume 39 inches.
4. Find the free point constant from stretch tables. Assume 760.

$$L = \Delta L C_{FPC} \div FD$$

$$L = 39 \times 760 \div 5 = 5,928 \text{ feet}$$

COILED TUBING STRETCH TABLES			
OD	WALL THICKNESS	CROSS SECTION AREA (IN ²)	FREE POINT CONSTANT
1.25	0.087	0.304	760
1.25	0.095	0.328	820
1.25	0.102	0.351	877.5
1.25	0.109	0.374	935
1.25	0.125	0.420	1,050
1.25	0.134	0.451	1,127.5
1.25	0.156	0.512	1,280

WELL CONTROL CONSIDERATIONS

Well intervention operations in a live well do not usually employ well control methods in the classic sense. In fact, a primary advantage of coiled tubing is the ability to work safely against well pressure.

The operational goals are achieved, not by removing a formation influx, but by *controlling* well pressure with surface equipment. Defining a well control incident is simple with regard to conventional (overbalanced) operations. Any unexpected influx of formation fluid fits the definition of a “kick.” However, the definition does not always apply to operations in which formation pressure remains greater than the hydrostatic pressure provided by the working fluid. Usually well intervention work is conducted in a slightly underbalanced condition, and if surface pressures exceed a pre-determined value during the operation, a control issue may develop. Classic well control methods are designed to maintain bottomhole pressure⁶ (BHP) equal to or slightly greater than wellbore pressure until the formation influx is removed and the well is dead. The opposite is true in well intervention work where the job is designed to be accomplished while remaining in an underbalanced condition.

There are two primary reasons for killing a well with coiled tubing: 1) an emergency situation in which wellhead pressure is considered excessive or 2) the operational program called for killing the well before beginning the operation. In either case the best (safest) situation is to take steps to kill the well using one of the four commonly used kill methods discussed below. Three of the methods described entail circulating a well with returns to the surface. Each *circulating method* is based on the idea that when a well is secured, the total bottomhole pressure (BHP) is equal to formation pressure and therefore, if the BHP remains constant, no further influx can enter the well.

- The Bullhead Method
- The Lubricate and Bleed Method
- The Driller’s Method
- The Wait and Weight Method

⁶ Bottomhole pressure in the context of pressure control is the total of all pressures exerted on the bottom of a well; for example, hydrostatic pressure, wellhead pressure, friction pressure.

It is common to apply some type of safety margin when planning a well-killing operation. In the case of The Bullhead Method, the safety margin may be in the form of over-displacement to ensure that the well is dead. When using a circulating method, a safety margin is often applied to the circulating pressure in order to prevent a further influx from entering the well during the operation. It is not possible to assign a specific safety margin that would be appropriate for all kill operations. Operators must select and recommend safety margins only after considering known formation characteristics as well as the overall goal of the

pending operation. It should be noted that in well intervention work, excessive safety margins can damage the producing formation to the point of negating the primary objectives of the job. On the other hand, too little safety margin may place the safety of the personnel and the environment in jeopardy. If a well is permanently damaged or even lost, that is certainly serious, but it is nothing when compared to the potential tragedy of a blowout and fire.

Bullheading is accomplished by forcing formation fluids (usually gas) back into a formation by pumping into the annulus from the surface. It is the most common kill technique used by coiled tubing units prior to entering a live well. A kill weight fluid (KWF) is selected that will provide a column that exerts a hydrostatic pressure greater than the formation pressure after the well has been fully displaced. The KWF and pumping rate is calculated to avoid excessive surface pressure but still provide enough downhole pressure to exceed the formation fracture integrity pressure. In most cases the reservoir must be micro-fractured in order to achieve sufficient injected volume to kill the well. Care must be taken so as not to exceed the overburden stress in the rock which might lead to horizontal fractures.

The *Lubricate and Bleed Method* (L&B) is used to remove gas from a well and replace it with fluid to accomplish the kill. A calculated volume of KWF is pumped (lubricated) into the well in stages and allowed to fall through the gas. Gas pressure equivalent to the hydrostatic pressure of the volume of fluid pumped is bled off through an adjustable choke. A bleed-off schedule (including safety factors) is constructed and followed as a guide during the operation. As the pressure of the remaining gas approaches zero and the fluid in the well nears the surface, the well can be filled with the remainder of the kill fluid. The process is continued until the kill weight fluid fills the wellbore. Note: The BHP is not held *perfectly* constant during the L&B operation; it is allowed to vary under controlled conditions during each stage of the operation.

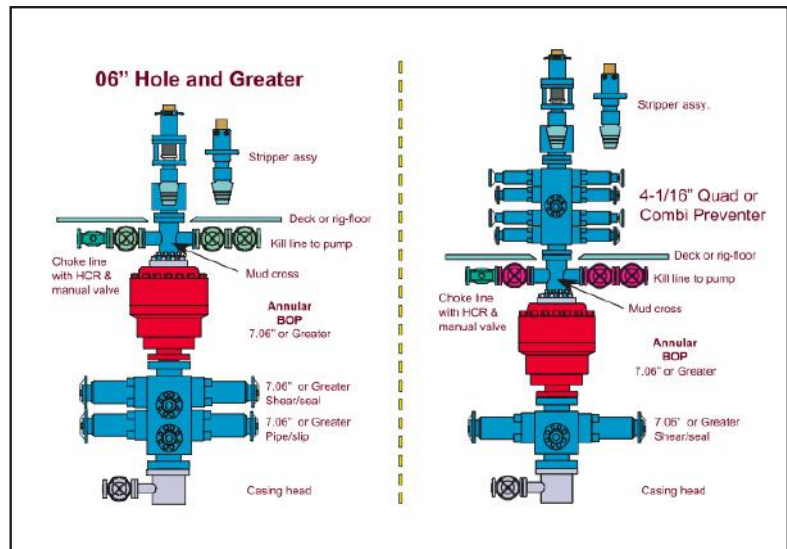


Figure a-47: rig-up and Circulation Options are Important Considerations

LUBRICATE & BLEED EXAMPLE

Assume a vertical well 9,445 feet deep with a packer set at 9,300 feet. Perforations begin at 9,310 feet and extend to bottom. The coiled tubing string is 2-3/8 in., 0.175 in wall thickness. It is further assumed that the well is secured (shut in). The check valves were opened by pressuring up the tubing in small increments until there was communication with the annulus. The shut in tubing pressure (SITP) was found to be 3,380 psi. Gas in the tubing is 0.12 psi/ft.

1. Determine the bottomhole pressure (BHP).

$$\text{BHP} = (0.12 \times 9,310) + 3,380 = 4,497 \text{ psi}$$

2. Determine the kill weight fluid density (KWF) with a 200 psi safety margin.

$$\text{KWF} = (4,497 + 200) \div 0.052 \div 9,310 = 9.7 \text{ ppg}$$

3. Determine capacity of the tubing (bbls/ft).

$$\text{ID} = \text{OD} - (2 \text{ wall})$$

$$\text{ID} = 2.375 - (2 \times 0.175) = 2.025 \text{ ins.}$$

$$\text{Capacity (bbls/ft)} = \text{ID}^2 \div 1029.4$$

$$2.025^2 \div 1,029.4 = 0.00398 \text{ bbls/ft}$$

4. Determine the hydrostatic pressure exerted by 1 barrel of kill fluid.

$$1 \div 0.00398 = 251 \text{ ft (per barrel kill fluid)}$$

$$9.7 \times 0.052 \times 251 = 126.6 \text{ psi}$$

5. Determine the volume of KWF equal to the 200 psi safety margin.

$$200 \div 126.6 = 1.58 \text{ bbls}$$

At this point a schedule can be constructed indicating the step-by-step process for the Lubricate & Bleed operation. The difference between the initial pressure and the pressure after bleeding gas during each step is called the *working margin*.

LUBRICATE & BLEED WORKSHEET

STEP	ACTIVITY	SAFETY MARGIN (PSI)	WORKING MARGIN (PSI)	VOLUME PUMPED (BBLs)	TOTAL VOLUME PUMPED (BBLs)	PRESSURE BLED	SITP (PSI)	BHP (PSI)
(psi)	SITP	0		0	0	0	3,380	4,497
(psi)	BHP	200		1.59	1.59	0	3,380	4,697
(psi)	Pump 2 bbls	200	252	2	3.59	0	3,380	4,949
3	Bleed Equiv. HP	200		0	3.59	252	3,128	4,697
4	Pump 2 bbls	200	252	2	5.59	0	3,128	4,949
5	Bleed Equiv. HP	200		0	5.59	252	2,876	4,697
6	Pump 2 bbls	200	252	2	7.59		2,876	4,949
7	Bleed Equiv. HP	200		0	7.59	252	2,624	4,697
8	Pump 2 bbls	200	252	2	9.59		2,624	4,949
9	Bleed Equiv. HP	200		0	9.59	252	2,372	4,697
10	Pump 2 bbls	200	252	2	11.59		2,372	4,949
11	Bleed Equiv. HP	200		0	11.59	252	2,120	4,697
12	Pump 2 bbls	200	252	2	13.59		2,120	4,949
13	Bleed Equiv. HP	200		0	13.59	252	1,868	4,697
14	Pump 2 bbls	200	252	2	15.59		1,868	4,949
15	Bleed Equiv. HP	200		0	15.59	252	1,616	4,697
16	Pump 2 bbls	200	252	2	17.59		1,616	4,949
17	Bleed Equiv. HP	200		0	17.59	252	1,364	4,697
18	Pump 2 bbls	200	252	2	19.59		1,364	4,949
19	Bleed Equiv. HP	200		0	19.59	252	1,112	4,697
20	Pump 2 bbls	200	252	2	21.59		1,112	4,949
21	Bleed Equiv. HP	200		0	21.59	252	860	4,697
22	Pump 2 bbls	200	252	2	23.59		860	4,949
23	Bleed Equiv. HP	200		0	23.59	252	608	4,697
24	Pump 2 bbls	200	252	2	25.59		608	4,949
25	Bleed Equiv. HP	200		0	25.59	252	356	4,697
26	Pump 2 bbls	200	252	2	27.59		356	4,949
27	Bleed Equiv. HP	200		0	27.59	252	104	4,697
28	Pump 2 bbls	200	252	0.8254	29.59		104	4,949
29	Bleed Equiv. HP	200		0	29.59	104	0	4,697

The *Driller's Method* involves two complete and separate circulations to kill an underbalanced well. The first circulation removes the influx out of the well; the second circulates heavier fluid throughout the wellbore. The Driller's Method is simple, direct and well-suited to coiled tubing operations. In order to kill a well by circulation methods, it is necessary that the end of the coiled tubing is positioned below the influx. That presents no significant problem for coiled tubing units since there are no tubular connections to be made up and because the unit is designed to inject (or retract) the tubing into live wells. Once the tubing is on bottom, or below the influx, the following steps outline the procedure for the first circulation.

- A slow circulating rate (SCR) is chosen and surface equipment is lined up to take returns thorough an adjustable choke at the choke manifold.
- The static (shut-in) wellhead pressure is noted.
- The choke is opened slightly and the pump is gradually brought up to the selected rate. During this time the choke operator maintains the wellhead pressure constant by choke manipulation.
- When the pump is at the selected rate and the wellhead pressure is at the original value, the circulating pressure, usually called the initial circulating pressure (ICP), is noted.
- From this point on throughout the circulation the ICP is maintained constant by choke manipulation.
- The ICP is actually the combination of the static shut-in tubing pressure (SITP) plus the pumping friction pressure; therefore, once established, the pump rate is not allowed to change. Once all the influx has been circulated out of the well, the pump can be shut down and the choke closed. At this time the well is not dead. Static or shut-in tubing pressure and shut-in wellhead pressure (SIWP) should be at approximately the same value.

If it is desired to kill the well with a second circulation, kill weight fluid (KWF) must be available before circulation begins. During the first circulation it was possible to control BHP with the circulating pressure because there was a consistent density fluid in both the tubing and the annulus. In the second circulation the fluid density in the tubing will constantly decrease until the tubing is displaced with kill fluid, after which time the annulus column will contain mixed densities until the kill mud arrives at the surface.

The steps for the second circulation are as follows:

- Start-up is exactly the same as in the first circulation: a constant wellhead pressure at the constant pump rate.
- Wellhead pressure is maintained constant as the kill fluid is pumped to the end of the string. During this time the tubing pressure will decrease steadily due to the increasing hydrostatic pressure inside the tubing string.
- When the tubing has been completely displaced with KWF and enters the annulus, the circulating pressure is noted.
- Circulation continues, holding the *tubing* (circulating pressure) constant until the annulus is displaced and the kill fluid returns to the surface.

The *Wait and Weight (W&W) Method* is considerably more complex than the Driller's Method and is rarely used in coiled tubing operations. This is especially true on highly deviated wells (more that 65°). The method is designed to kill a well in one circulation and requires either good fluid mixing equipment or an adequate supply of kill weight fluid (KWF) on location. The operation is planned ahead of time, usually with a job aid called a *killsheet*. Standard

killsheets, designed for use by conventional rigs in near-vertical wells, are fairly simple and can be completed manually in a short time. However electronic killsheets, in conjunction with computer programs, should be used for coiled tubing operations.

The complexity of the operation is due to several things:

- When circulation begins the circulating pressure will *increase* (if BHP is to be held constant) due to friction caused by pumping the KWF until the tubing on the reel is displaced. The increase is depth-dependent: the more tubing on the reel, the greater the friction.
- The pumping friction at a slow rate (without influx) should be known before the operation begins so that the initial circulating pressure (ICP) can be pre-determined.
- The ICP will not be attained until the kill fluid begins the vertical descent into the string.
- As the kill fluid is pumped down the tubing, the circulating pressure must be allowed to *decrease*, according to a pre-calculated schedule, until the kill fluid reaches the bottom of the string in order to compensate for the gain in hydrostatic pressure inside the tubing. The circulating pressure at that time is called the final circulating pressure (FCP) and is held constant until the well is completely displaced with kill fluid.

In order to better understand these limitations, consider a conventional drilling rig that has taken an influx while drilling overbalanced in a near-vertical well. Once the well is secured, the shut in tubing pressure (SITP) and the shut in wellhead pressure (SIWHP) are recorded. If the operator decides to kill the well using the W & W Method, four basic calculations are required: 1) kill fluid density (KWF), 2) initial circulating pressure (ICP), 3) final circulating pressure (FCP) and 4) the volume in the string, barrels or pump strokes (STB).

$$KWF(ppg) = (SITP \div 0.052 \div TVD) + OFD \text{ (original fluid density)}$$

$$ICP(psi) = SCP^7 + SITP$$

In overbalanced drilling SCP can be found as explained in the Driller's Method above or has been previously recorded.

$$FCP(psi) = SCP \times KWF \div OFW$$

$$STB(bbls) = ID^2 \div 1029.4 \times MD$$

Once this data is collected, a simple pressure/volume pumping schedule can be constructed by dividing the difference between the ICP and FCP into convenient volumetric check points to use as a guide when pumping the KWF from the surface to the end of the string (TVD).

⁷ SCP (Slow circulating pressure) is the circulating (friction) pressure at some pre-selected pumping rate when there is no influx in the well

The kill operation consists of these five steps:

1. The wellhead pressure is held at its shut-in value by means of choke adjustments as the pump is brought up to the selected kill rate.
2. When the kill rate is achieved, the choke operator adjusts the *circulating pressure* to ICP.
3. The circulating pressure is allowed to decrease according to the constructed schedule. The pump rate is not allowed to change.
4. When the string is filled with KWF, the circulating pressure should be the FCP.
5. The FCP is maintained until kill fluid is circulated throughout the well.

The procedure outline above is simple and direct on a drilling rig because the SCP is known or can be easily be determined by either: 1) pumping at a constant rate and pre-recording the pressure if the well is overbalanced, or 2) holding the wellhead pressure constant until the pump rate is achieved and recording the circulating pressure if the well is underbalanced. The SCP is the difference between the SITP and the recorded pressure.

This is not true with coiled tubing. An accurate ICP cannot be calculated unless the SCP is known. When a coiled tubing unit begins to pump the denser kill fluid (maintaining a constant wellhead pressure), the friction pressure at the selected pumping rate will increase until the fluid begins its vertical descent down the string. In other words there would actually be *two* initial circulating pressures. ICP1 when the pump was at the kill rate and ICP2 when the tubing on the reel had been displaced. The pumping schedule would start at ICP2 and end at FCP. There is no simple way to determine the friction increase as the tubing on the reel is displaced with kill fluid. It will depend on several factors, such as the ID of the tubing, the length of tubing on the reel, the density and flow properties of the fluids and the pumping rate. The only way that this pressure increase can be accurately predicted is by means of complex hydraulic calculations, well-suited for a computer but not for pencil and paper.

The operation becomes even more complicated in highly deviated wells. In a vertical well, the kill fluid causes the circulating pressure to decrease due to the increasing hydrostatic pressure and the increased friction pressure, both as a result of the heavier kill fluid. These two effects are practically simultaneous in vertical wells. However, in deviated wells they are not simultaneous. For example, a horizontal well would be theoretically dead when the kill fluid reached the horizontal point (HoP), but the friction would continue to increase until the entire string is displaced. Tracking bottomhole pressure and determining the correct circulating pressure as the kill fluid moved around the radius of curvature from vertical to horizontal is virtually impossible unless computers are used to plan and execute the operation.

SECTION 6: NITROGEN/COILED TUBING APPLICATIONS

Nitrogen is used extensively in coiled tubing operations all over the world. There are nitrogen generating units used in some areas where liquid nitrogen is not readily available for delivery. Most commonly, it is delivered to wellsite locations in large tanks in its liquid form.

Nitrogen has many applications in remedial activities, including:

- Unloading Wells
- Fracture Proppant Transport
- Sand Washing
- Dry Perforating
- Setting Packers



Figure a-48: a niTrogen uniT

Nitrogen handling equipment consists of:

- A storage vessel (cryogenic tank)
- Pumping system
- A gasifier (usually a heat exchanger)
- Controls necessary for operating the equipment

Although nitrogen is a chemically inert gas, liquid nitrogen and its conversion to gas can be extremely hazardous. Nitrogen is *cryogenic* material with a boiling point of approximately -320°F at atmospheric pressure. Liquid nitrogen is transported and stored in specially constructed stainless steel tanks capable of withstanding the extreme cold. The tanks are constructed with an inner tank enclosed in an outer shell tank. Insulation between the two tanks is provided by vacuum. The tanks have venting devices with gauges and rupture disks to prevent pressure buildup between the inner tank and the shell. Sudden jolts, vibration or shock could cause the supports between the tanks to break; therefore, extreme caution must be taken whenever the tanks are moved. Any significant spill of liquid nitrogen within the outer shell could cause the nitrogen to vaporize faster than it can be vented.

Working with liquid nitrogen presents a significant personnel hazard and requires approved personal protective equipment (PPE) to be worn at all times. No liquid nitrogen must be allowed to come into contact with the skin. Handling any material that converts from a liquid state to a large volume of gas requires adequate training and extreme caution. If a hose or a short section of pipe which contained liquid nitrogen were to be trapped by valves on either end, the combination of ambient air plus lack of insulation would cause a rapid pressure build-up within the vessel. Hoses and equipment used for linking the nitrogen tanks for liquid transfer must be managed according to strict safety standards. If liquid nitrogen is spilled on the ground in a low-lying area, a low oxygen environment can result. Also, if gaseous nitrogen is bled off too rapidly, the hazards of extreme noise and high velocity gas stream come into play.

Liquid nitrogen must be gasified before it is injected into coiled tubing for circulating downhole. The liquid is pumped into a gasifier unit by a high pressure pump designed for cryogenic operations. The nitrogen changes state and expands under controlled conditions, then is routed to a manifold for injection into the coiled tubing string.

A common coiled tubing/nitrogen operation is to inject the gas only (single phase injection). The gas is routed from the gasifier to the service reel and downhole to bring a well on line or to “unload the well.” This method of regaining or re-starting production is fast and; therefore, cost-effective. A well that has a fluid column exerting enough hydrostatic pressure to prevent the well from flowing can lighten the fluid column by injecting nitrogen, thus reducing bottomhole pressure to the point at which the reservoir fluids can flow naturally into the wellbore. The process is known as “kicking the well off.” In many cases the well will continue to flow even after nitrogen injection has stopped. An added benefit is the nitrogen provides a means to deliver an uncontaminated sample of formation fluid.

There are a variety of operations in which nitrogen gas is used. Sometimes wells are cleaned up or washed out with a mixture of nitrogen and liquid. Acids can be mixed with nitrogen to improve treatment efficiency. In other cases, treatment fluids can be atomized at the surface to enhance mixing the nitrogen with the liquid phase. An atomizing tee is installed where the gas stream and the liquid stream meet. The gas is used to agitate the liquid acid or treatment fluid as it is mixed with the gas. “Nitrofied” fluids contain less than 50% nitrogen in these mixtures.

In some cases it is better to create a foamed fluid to carry debris from the wellbore. Foams are extremely effective at carrying solids and will carry a higher load of solids per volume than any other fluid mixture. However, the efficiency of the foam is limited to a relatively narrow band of foam *quality*. Foam quality is defined as the ratio of the total gas volume per total volume of the mixture. The foam quality must be maintained throughout the wellbore to ensure stability of the foam and effective transport of the solids to the surface. Because the gas volume of the foam changes with wellbore pressure, the foam quality changes (increases) as the foam moves up the wellbore. When foams approach 100% quality, they become unstable and break down, losing solids transport effectiveness. A significant risk of sticking the string in the well exists if the foam system only transports the solids to another section of the wellbore before it breaks down.

SUMMARY

Coiled tubing and nitrogen units are easily transportable, rig-up in a short time and can perform a variety of remedial work in less time than conventional workover units due to their capability of operating against well pressure while at the same time circulating and moving the tubing within a well. Modern coiled tubing units employ sophisticated computer programs to track all phases of a job, including bend-cycle fatigue of the coiled tubing itself.

SECTION 7: PRACTICE CALCULATIONS

CALCULATING VOLUME AND CAPACITY

In order to calculate the total volume in a coiled tubing string, it is first necessary to determine the capacity. *Capacity* may be defined as the volume contained in a specific length of the cylinder; for example, barrels per foot, gallons per foot, etc. The formula below is commonly accepted as a means to determine tubular capacity in barrels per foot (bbls/ft).

$$\text{Cap} = \text{ID}^2 \div 1,029.4$$

Where:

Cap = Capacity, bbls/ft

ID = inside diameter, ins

1029.4 = a constant used to convert inches diameter to oilfield barrels per foot.

Although the dimensions of jointed pipe (drillpipe and tubing) are often given in inches as outside diameter (OD) and inside diameter (ID), coiled tubing is often described by OD and wall thickness. For example, OD 2.375 in, 0.156 wall. The ID is the difference between the OD and twice the wall thickness.

$$\text{ID} = \text{OD} - (2 \times W)$$

Where:

ID = inside diameter, in

OD = outside diameter, in

W = CT wall thickness

In the explanation above the ID of 2.375 in CT with a wall thickness of 0.156 in is calculated to be:

$$\text{ID} = 2.375 - (2 \times 0.156)$$

$$\text{ID} = 2.063 \text{ ins}$$

Therefore, the capacity of this tubing is $2.063^2 \div 1,029.4 = 0.0041344$ bbls/ft. It can be seen that this is a relatively small capacity. In fact, it is not usually practical to use bbls/ft in coiled tubing work because the entire volume of the coiled tubing must be pumped regardless of the working depth. A more practical way to determine the CT volume would be to express the capacity in bbls/1000 ft or perhaps according to the total length of tubing in use. For example, if there was a total of 15,000 ft of CT the calculation would be:

$$2.063^2 \div 1029.4 \times 15,000 = 62 \text{ bbls}$$

When coiled tubing is run into a well, the capacity of the space between the two cylinders, that is, between the CT and the casing, tubing or open hole, is the *annular capacity*. When solving for the annular capacity, it is necessary to find the difference between the *squares* of the diameters of the cylinders before applying the conversion factor.

$$\text{Annular capacity, bbls/ft} = (ID^2 - OD^2) \div 1,029.4$$

Where:

ID = inside diameter of the host cylinder (casing, tubing, etc.), inches

OD = outside diameter of coiled tubing (innermost pipe), inches

Example:

What is the annular capacity (bbls/ft) if 2.375-inch OD coiled tubing is injected into 4.5-inch OD drillpipe? The ID of the drillpipe is 3.563 ins.

$$\text{Annular capacity} = (3.563^2 - 2.375^2) \div 1,029.4$$

$$\text{Annular capacity} = 0.0068528 \text{ bbls/ft}$$

Once again, it can be seen that the annular capacity in the example is a very small number. Since coiled tubing can be moved within a well while pumping, it might be more practical to choose a working depth and apply that depth to the calculation. For instance, the 4.5-inch drillpipe might extend to 9,000 ft but the coiled tubing is working at a shallower depth of 8,250 ft. Therefore the annular volume at 8,250 ft is:

$$(3.563^2 - 2.375^2) \div 1,029.4 \times 8,250 = 56.54 \text{ bbls}$$

CALCULATING DISPLACEMENT

For the purpose of this discussion, *displacement* is the volume of fluid forced out of a well as the coiled tubing string is run in. It is true that when running in, well fluids can be forced into a formation or otherwise compressed, but those situations are ignored here.

Units that use jointed pipe as the work string speak of running in or pulling out of a well as “tripping wet” or “tripping dry.” If the pipe is “dry,” it simply means that it is open at both ends. There is no non-return valve (NRV) at the lower end, and the upper end is open at the surface. In other words, the pipe is empty. In this case the total displacement is the volume of steel deployed or retrieved. If the string is run or pulled “wet,” it means that the pipe is full of fluid. There is a considerable difference between the displacement of a dry string and a wet string; therefore, tracking the displacement of jointed pipe on trips is a major component of well control planning.

Making dry or wet trips is generally not applicable to coiled tubing operations. Deploying or retrieving a dry, or empty, string of CT could happen only in the rarest of circumstances. In such a situation there would be no NRV

at the lower end of the string, and at the upper end, the CT on the service reel would have to be empty and open to atmospheric pressure. It is possible to imagine a situation in which the CT had been sheared or otherwise parted near the surface and had been hung off in the slip rams, but this is very unlikely. For all practical purposes, it can be assumed that coiled tubing, whether being injected into or extracted out of a well, is full of fluid. In other words, the string is “wet.” The displacement of the coiled tubing can be found by:

$$\text{Displacement, bbls/ft} = \text{OD}^2 \div 1,029.4$$

Using the example above the displacement of 2.375-in CT is $2.375^2 \div 1,029.4 = 0.0054795$ bbl/ft

If 8,250 feet of CT were deployed the 45.2 bbls would be displaced from the well ($0.0054795 \times 8,250 = 45.2$ bbls).

CALCULATING A WATER CUSHION

When perforating casing below a production packer, a “water cushion” is sometimes used to create a pressure underbalance in the area to be perforated. The object of underbalanced perforating is to cause an immediate backflow of debris and mud solids through the new perforations. The debris falls to the bottom of the casing, thus allowing formation fluids to flow freely into the well. In order to calculate the length (height) of the water cushion, it is necessary to have a good estimate of the formation pressure.

$$\text{Water cushion, ft}^3 = (\text{FP} - \Delta\text{P}) \div \text{G}$$

Where:

FP = formation pressure, psi

ΔP = desired underbalance, psi

G = fluid gradient of cushion, psi/ft

Example:

It is desired to perforate the casing at a depth of 9,240 ft with an underbalance of 300 psi. The formation pressure is 3,960 psi. How many vertical feet of 9.3 ppg brine water are required to achieve the desired underbalance?

$$\text{G} = 9.3 \times 0.052 = 0.4836 \text{ psi/ft}$$

$$\text{Water cushion} = (3,960 - 300) \div 0.4836$$

$$\text{Water cushion} = 7,568 \text{ ft}$$

⁸ The water cushion solution is vertical feet since the object is to create a differential pressure.

CALCULATING BUOYANCY

An upward (buoyant) force is applied to an object when it is immersed in a fluid. The buoyant force is equal to the weight of the fluid that the object displaces. Several conditions affect buoyancy; for example, the air weight of the tubing, the density of the fluid in which the tubing is run, the length of tubing deployed and the density of the fluid inside the tubing (if any). The following discussion assumes a coiled tubing string with a NRV installed and the CT filled with fluid. The formula below is used to determine the buoyant weight of the string full of fluid (liquid).

$$B_w = (65.4 - FD) \div 65.4 \times T_w \times L$$

Where:

B_w = Buoyed weight, lbs

T_w = Pipe weight in air, pounds per foot, ppf

L = Length of tubing, ft

FD = Fluid density, ppg

65.4 = density of steel, ppg

Example:

Determine the buoyed weight of a string of 2 in, 0.156 wall, 3.08 ppf coiled tubing when 6,700 ft has been injected into a well in which the density of the working fluid is 13.2 ppg. The CT string is also filled with 13.2 ppg fluid.

$$B_w = (65.4 - 13.2) \div 65.4 \times 3.08 \times 6,700$$

$$B_w = 16,471 \text{ lbs}$$

The example above assumes that the fluid density in the well (13.2 ppg) is also the fluid inside the CT string. In coiled tubing work it is not uncommon to have one fluid inside the CT string and a different fluid in the CT annulus. The formula below can be used to determine the buoyed weight of the CT string when there is a difference between the fluid densities inside the CT and the fluid in the annulus.

$$B_w = L \times [TW - \{(OD^2 \times 0.0408 \times FD_1)\} + \{(ID^2 \times 0.0408 \times FD_2)\}]$$

Where:

FD_1 = Fluid density inside the coiled tubing.

FD_2 = Fluid density inside CT annulus

Example:

Using the data in the previous example, assume the fluid inside the CT is 11.2 ppg and that the fluid in the well remains 13.2 ppg.

$$ID = OD - (2 \times W)$$

$$ID = 2 - (2 \times 0.156)$$

$$ID = 1.688$$

$$B_w = L \times [\text{pipewt} - \{OD^2 \times 0.0408 \times MW_1\} + \{ID^2 \times 0.0408 \times MW_2\}]$$

$$B_w = 6,700 \times [3.08 - \{4 \times 0.0408 \times 13.2\} + \{2.849 \times 0.0408 \times 11.2\}]$$

$$6,700 \times [3.08 - 2.15 + 1.3]$$

$$6,700 \times 2.23$$

$$B_w = 14,941$$